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MECG – Exhibit 400P
Greg R. Meyer
Direct Testimony
File Nos. ER-2022-0129 & ER-2022-0130

Issue: Revenue Requirement
Witness: Greg R. Meyer
Type of Exhibit: Direct Testimony
Sponsoring Parties: Midwest Energy Consumers Group
Case Nos.: ER-2022-0129 & ER-2022-0130
Date Testimony Prepared: June 8, 2022

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**
In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service	)	**Case No. ER-2022-0130**

Direct Testimony and Schedules of

Greg R. Meyer

On behalf of

Midwest Energy Consumers Group

REDACTED VERSION

June 8, 2022

BRUBAKER & ASSOCIATES, INC.

Project 11259 & 11260

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Greg R. Meyer

Greg R. Meyer, being first duly sworn, on his oath states:

1. My name is Greg R. Meyer. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Midwest Energy Consumers Group in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and schedules which were prepared in written form for introduction into evidence in the Missouri Public Service Commission, Case Nos. ER-2022-0129 & ER-2022-0130.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

Greg R Meyer

Greg R. Meyer

Subscribed and sworn to before me this 8th day of June, 2022.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2023
Commission # 15024862

Tammy S Klossner

Notary Public

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Direct Testimony of Greg R. Meyer

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal at Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Midwest Energy Consumers Group ("MECG").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony will address the following areas:

- The historic change in Evergy Metro ("Metro") formerly referred to as Kansas City Power & Light Company ("KCPL") and Evergy West ("West") formerly referred to as KCP&L Greater Missouri Operations ("GMO") overall rates as well as how those rates compare to the national average electric rates;
- The Metro and West earned returns;
- The adjustments necessary to reflect the retirement of the Sibley generating units;
- The request by Metro to change the Missouri/Kansas jurisdictional allocation factors;
- The request by Metro and West to establish a bad debt expense tracker;
- The request by Metro and West to establish a property tax tracker;
- The request by Metro and West to establish a storm reserve;
- The request by Metro to increase nuclear depreciation expense;
- The request by Metro to increase overtime labor expense;
- The request by Metro and West to increase property tax expense;
- The request by Metro and West to change rates to reflect a Federal Corporate Income Tax rate change; and
- A discussion of the Crossroads Energy Center and verification of cost exclusion from cost of service.

The fact that I do not address a particular issue in this testimony should not be interpreted as a tacit approval of a position taken by the Companies on that issue.

I. Metro and West Rates

Q HOW HAVE METRO/KCPL RATES CHANGED OVER THE PAST 15 YEARS?

A Metro/KCPL has had eight rate cases since January 2007. The dates of those increases and the magnitude of the increases are reflected in Table 1:

TABLE 1
Evergy Missouri Metro (Formerly Kansas City Power & Light Company)

Rate Case History
Dollars in Thousands

Case No.	Requested Base Rate Increase	Granted Base Rate Increase	Difference	Percent of Request Rejected	Date of Rate Change
ER-2006-0314	$55,800	$50,600	$5,200	9.32%	January 2007
ER-2007-0291	45,400	35,309	10,091	22.23%	January 2008
ER-2009-0089	101,500	95,000	6,500	6.40%	July 2009
ER-2010-0355	92,100	34,817	57,283	62.20%	May 2011
ER-2012-0174	105,700	67,391	38,309	36.24%	February 2013
ER-2014-0370	120,900	89,700	31,200	25.81%	September 2015
ER-2016-0285	90,100	32,500	57,600	63.93%	May 2017
ER-2018-0145	16,400	(21,100)	37,500	228.66%	November 2018

Source: S&P Global IQ

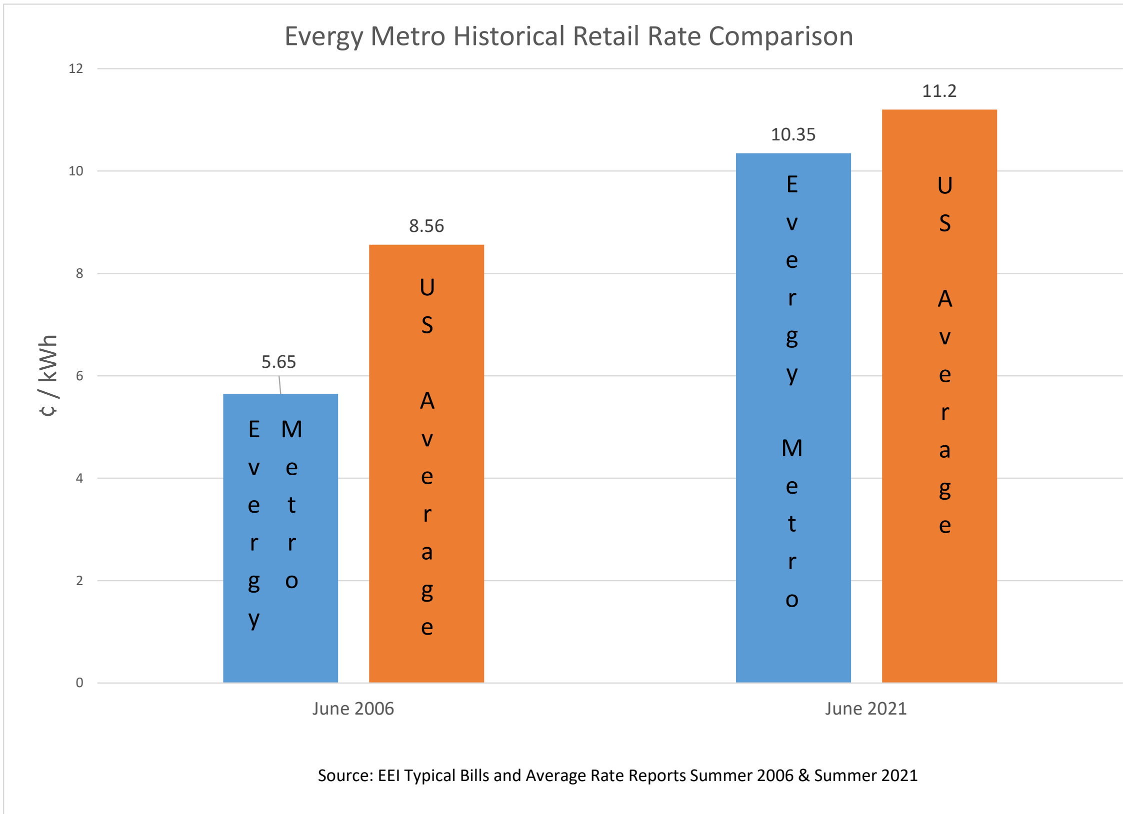
In those eight rate cases, Metro/KCPL requested rate increases totaling approximately $628 million. Metro/KCPL was authorized to raise rates by approximately $384 million, or about 61% of its request.

Q HOW COMPETITIVE ARE METRO'S RATES?

A According to Edison Electric Institute's ("EEI") Typical Bill and Average Rates Report, KCPL's average rate was 5.65 cents/kWh as of June 30, 2006. In contrast, the national average rate was 8.56 cents/kWh. Therefore, KCPL's average rate was 34% below the national average, or the national average rate was 51.5% above the KCPL average rate. In other words, KCPL's rates were very competitive within the United States at June 2006.

At June 30, 2021, Metro's average rate is 10.35 cents/kWh and the national average is 11.20 cents/kWh. Since 2006 Metro's/KCPL's average rate has increased 83%, the national average has increased by 31%. Metro's rates have declined in their comparative competitiveness with the national average; therefore, Metro must maintain strict cost controls. I have prepared Table 2 for ease of comparison.

TABLE 2



Q DO YOU HAVE SIMILAR INFORMATION FOR WEST/GMO?

A Yes. West/GMO has had seven rate cases since March 2006. The dates of those rate increases and the magnitude of the increases are reflected in Table 3.

TABLE 3
Evergy Missouri West (Formerly Kansas City Power & Light Company - Greater Missouri Operations)

Rate Case History
Dollars in Thousands

Case No.	Requested Base Rate Increase	Granted Base Rate Increase	Difference	Percent of Request Rejected	Date of Rate Change
ER-2005-0436 (L&P + MPS)	$78,600	$44,800	$33,800	43.0%	March 2006
ER-2007-0004 (L&P + MPS)	118,900	58,800	60,100	50.5%	June 2007
ER-2009-0090 (L&P + MPS)	83,110	63,000	20,110	24.2%	September 2009
ER-2010-0356 (L&P + MPS)	97,900	65,494	32,406	33.1%	July 2011
ER-2012-0175 (L&P + MPS)	83,500	47,942	35,558	42.6%	February 2013
ER-2016-0156 (L&P + MPS)	59,311	3,000	56,311	94.9%	February 2017
ER-2018-0146 (Consolidated Rates)	19,307	(24,000)	43,307	224.3%	November 2018

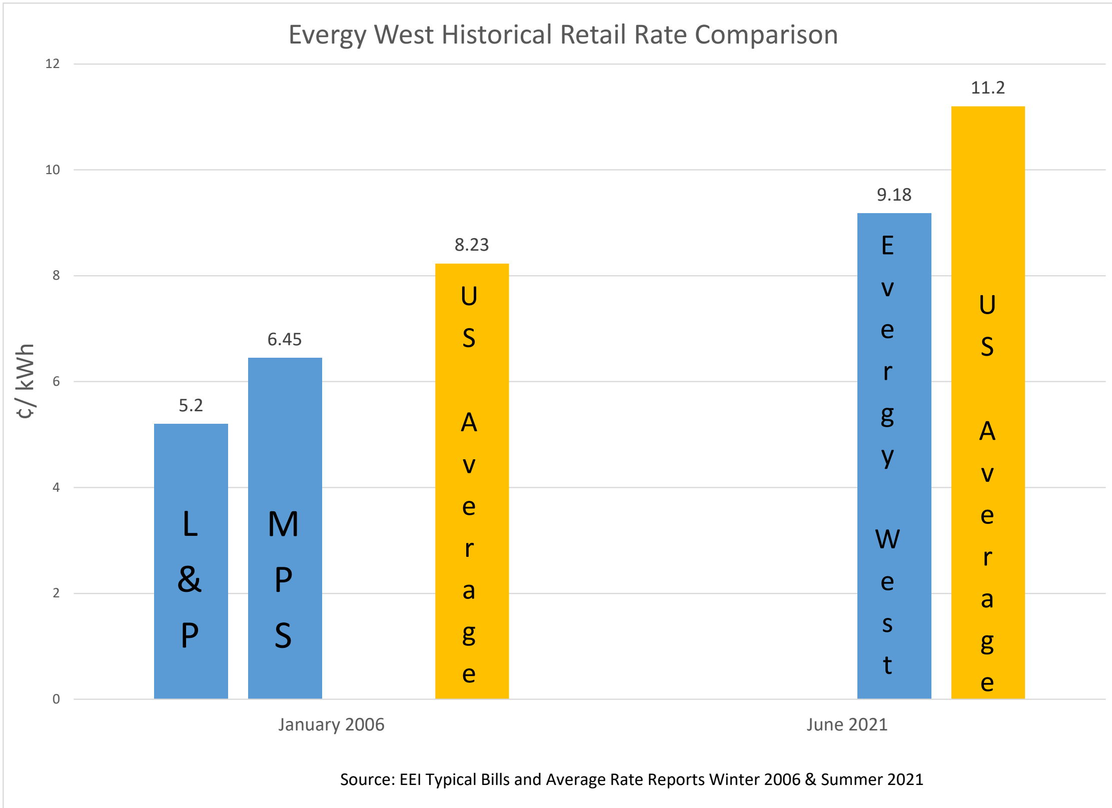
Source: S&P Global IQ

In those seven rate cases, West/GMO requested rate increases totaling approximately $541 million. West/GMO was authorized to raise rates by approximately $259 million, or about 48% of its request.

Q HOW DO WEST/GMO'S RATES COMPARE TO THE NATIONAL AVERAGE?

A On January 2006, GMO-MPS' average rate was 6.45 cents/kWh and the GMO-L&P's average rate was 5.20 cents/kWh. The national average rate on January 2006 was 8.23 cents/kWh. On June 30, 2021, the West average rate was 9.18 cents/kWh and the national average rate was 11.20 cents/kWh. I have prepared Table 4 for ease of comparison.

TABLE 4



1 **Q I NOTICED THAT YOU USED DIFFERENT TIME PERIODS FOR YOUR RATE COMPARISONS FOR THE METRO AND WEST OPERATIONS. PLEASE RESPOND.**

A I used the most recent reported EEI price data that occurred prior to the first rate order for both Metro and West operations. For example, Metro/KCPL had its first rate case decision in Table 1 on January 2007. Therefore, I used the EEI price comparison data for June 2006. Likewise, West/GMO had its first rate case reported on Table 3 on March 2006. Therefore, I used the January 2006 EEI price data.

II. Metro and West Earned Returns

Q HAVE YOU REVIEWED THE EARNED RETURNS OF THE METRO AND WEST OPERATIONS?

A Yes. I have reviewed the last eight quarters of surveillance reports filed with Metro and West's fuel adjustment clause filings.

Q WHAT WERE THE RESULTS OF YOUR REVIEW?

A I have prepared Confidential Table 5 that shows the recorded return on equity ("ROE") achieved by Metro and West during the last eight quarters.***

[redacted]***

III. Sibley Retirement

Q PLEASE DESCRIBE THE SIBLEY UNITS.

A The Sibley generating units were initially constructed by MPS.[1] Sibley Unit 1, completed in June 1960, had a capacity of 48 MW. Sibley Unit 2, completed in May 1962, had a capacity of 51 MW. Sibley Unit 3, built in 1969, had a capacity of 364 MW.

In 1991, MPS completed a major renovation of the Sibley units to extend the life of the units and to allow the units to burn low sulfur western coal. MPS sought and was granted an Accounting Authority Order ("AAO") to defer depreciation and the capital costs associated with this renovation project. The Commission found, "that [the Sibley projects] were extraordinary events and that depreciation expenses and carrying costs could be deferred to MPS's next rate case."[2]

In June 2017, Sibley Unit 1 was retired. On June 2, 2017, the Company announced it planned to retire the entire Sibley station by December 31, 2018; however, the retirement could be delayed by unforeseen circumstances such as the loss of other Evergy Missouri West generating facilities. As stated in the Company's announcement, the factors contributing to Sibley's retirement included: (1) the reduction in wholesale electricity market prices, (2) a reduction in the required reserve generating capacity, (3) a decline in near-term capacity needs, (4) the age of the Sibley plants, and (5) expected environmental compliance costs.

On September 5, 2018, Unit 3 suffered a forced outage as a result of turbine vibrations and ceased generating electricity at that time. After an investigation was conducted, Evergy Missouri West decided that rather than repair Unit 3 at an estimated

[1]MPS- Missouri Public Service Company.
[2]Report and Order, Case No. EO-91-358, 1 MoPSC 3d 200.211 (issued December 20, 1991).

cost of $2.21 million, the Sibley station would be retired roughly six weeks (November 2018) prior to its planned retirement date of December 31, 2018.

During the course of these events, Evergy was involved in rate cases, Case Nos. ER-2018-0145 and ER-2018-0146. Rates from those rate cases became effective December 6, 2018. Rates in those rate cases were based on revenues, costs, and investments as of a true-up date of June 30, 2018. Since the Sibley Units 2 and 3 were formally retired after the true-up date, Evergy's current rates would include costs, revenues, and investment associated with the Sibley units.

On April 23, 2019, the MECG and the Office of Public Counsel ("OPC") filed a complaint case seeking to capture through an AAO the capital and operating costs currently in Evergy's rates following the retirement of the Sibley generating units. The Commission granted the requests made by MECG and the OPC and ordered that Evergy begin recording to a regulatory liability the following:

- Return on the Sibley unit investments;
- Non-fuel operation and maintenance ("O&M") costs;
- Taxes, including accumulated deferred income taxes; and
- All other costs associated with the Sibley units and common plant.

Evergy has complied with the Commission Order and recorded a regulatory liability to capture the cost savings from the retirement of the Sibley units.

Q WHAT HAS EVERGY PROPOSED FOR THIS RATE CASE REGARDING THE SIBLEY RETIREMENT?

A Evergy has proposed to amortize the regulatory liability from the accumulation of non-fuel O&M expenses and labor costs over four years. Evergy has also requested that the unrecovered investment in the Sibley plants be amortized over 20 years.

Q DO YOU AGREE WITH THE EVERGY PROPOSAL?

A No. I do not believe Evergy has captured all of the costs savings from the retirement of the Sibley units. In addition, I believe the value of the unrecovered investment in the Sibley units is significantly understated.

Q LET'S BEGIN WITH THE REGULATORY LIABILITY. DO YOU BELIEVE EVERGY HAS UNDERSTATED THE VALUE OF THE REGULATORY LIABILITY?

A Yes. Evergy has included the non-fuel O&M and labor expenses in the amount to be amortized. However, Evergy excluded the return on the Sibley investments from the date of retirement. I believe that the return on the Sibley units should also be a component of the regulatory liability balance.

Q WHY DO YOU PROPOSE TO INCLUDE THE RETURN ON THE SIBLEY UNITS FROM THE DATE OF RETIREMENT?

A I do not think that ratepayers should provide a profit stream for investments that are no longer used and useful. There is no debate that in mid-November 2018, the Sibley units were retired and ceased operations. At that time, the Sibley units stopped producing energy for Evergy customers and as such were not used and useful. To require ratepayers to continue to provide a profit return on plants that are not used and useful is wrong. Therefore, the return on the Sibley units should be accumulated from the date of retirement until the date for new rates in this rate case and amortized to Evergy ratepayers.

Q DO YOU HAVE AN ESTIMATE OF THIS AMOUNT?

A Yes. Referring back to the Staff's Accounting Schedules from the last rate case, Case No. ER-2018-0146, the undepreciated balance for the Sibley units was approximately $300 million. A rate of return assuming a 9.5% Return on Equity ("ROE") would equate to a pre-tax rate of return of 8.576%.[3] Applying that rate of return to the undepreciated balance yields a return allowance of approximately $25.7 million.[4] Factoring that return over four years equates to a regulatory liability for return of approximately $102.9 million. I would propose that the $102.9 million be added to the regulatory liability balance estimated by Evergy for the recovery of non-fuel O&M and labor costs of $39.1 million that sums to a total regulatory liability of approximately $142 million.

Q HOW DO YOU PROPOSE TO ADDRESS THE $142 MILLION REGULATORY LIABILITY THAT YOU HAVE CALCULATED?

A I will provide my recommendation on how to address the regulatory liability after I have discussed all aspects of the Sibley units retirements.

Q TURNING YOUR ATTENTION TO THE UNDEPRECIATED BALANCE FOR THE SIBLEY UNITS, WHAT LEVEL OF UNDEPRECIATED INVESTMENT HAS EVERGY CLAIMED EXISTS AT RETIREMENT?

A Evergy claims the current undepreciated balance of the Sibley units is $104.2 million.

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[3]8.576%= 9.5% ROE*47.43% *1.313 + Long term debt of 5.06% * 52.57%.
[4]Undepreciated Sibley investment $299,947,216 * 8.576%.

Q PLEASE DESCRIBE YOUR CONCERNS WITH THE UNDEPRECIATED BALANCE FOR THE SIBLEY UNITS AS PROPOSED BY EVERGY.

A I believe the undepreciated balance proposed by Evergy is significantly understated. I have gone back to the Staff Accounting Schedules from the last rate case and pulled the plant-in-service and accumulated depreciation balances from those Accounting Schedules at June 30, 2018. At June 30, 2018, the Sibley units had an undepreciated balance of approximately $300 million. I then updated the accumulated depreciation reserve balances for the period of time between June 30, 2018 and the operation of law date in this case, December 6, 2022. Updating the accumulated depreciation reserve balances to December 6, 2022, yielded an adjusted undepreciated balance for the Sibley units of approximately $254 million.

Q HOW DO YOU RECONCILE THE DIFFERENCE BETWEEN THE $104.2 MILLION PROPOSED BY EVERGY AND THE $254 MILLION YOU CALCULATED?

A In the complaint case, Case No EC-2019-0200, Evergy witness John Spanos calculated an undepreciated investment balance of approximately $145.7 million for the Sibley units. Mr. Spanos stated that this balance was derived from a theoretical depreciation calculation. However, for purposes of the revenue requirement calculation, the Sibley units reserve balances were significantly less than those proposed by Mr. Spanos. To arrive at the current level proposed by Evergy, Mr. Spanos simply updated his analysis from the complaint case. However, those accumulated reserve balances are still significantly understated.

Q WHICH UNDEPRECIATED RESERVE BALANCE SHOULD THE COMMISSION RELY ON?

A I believe the Commission should rely on the reserve balances that were used by the Staff in Evergy's last rate case to set rates. Mr. Spanos' undepreciated reserve balance was calculated using a theoretical depreciation methodology that would not reflect the actual accumulated depreciation reserve balances used to set rates.

Evergy has reduced the accumulated depreciation reserve balances from other steam generating units to address the difference in the undepreciated value of the Sibley units at retirement. I have prepared Table 6 that shows the change in accumulated depreciation balances from the Staff's Accounting Schedules in the last rate case and the current accumulated depreciation balances proposed by Evergy in this rate case. I have also updated the Staff's accumulated reserve balances to reflect the estimated value of those reserves at December 2022.

TABLE 6

Comparison of Accumulated Depreciation Reserves

Generating Unit	Evergy Proposed ER-2022-0130	Staff Accounting ER-2018-0148	Updated thru December 2022	Difference
Jeffrey Energy	$59,681,925	$81,691,593	$94,505,412	$34,823,487
Lake Road	$31,539,649	$45,708,010	$52,945,349	$21,416,700
Iatan Common	$2,893,940	$13,023,044	$18,254,174	$15,360,234
Iatan 1	$37,320,128	$49,105,670	$57,700,940	$20,380,812
Iatan 2	$6,825,903	$50,491,803	$70,867,836	$64,041,933
			TOTAL	$156,023,166

As can be seen from Table 6, the reported accumulated depreciation balances proposed by Evergy in this case (Column 1) are significantly below the levels used by the Staff in Evergy's last rate case (Column 2). Generally, accumulated depreciation balances increase over time except for major plant retirements in that account. Major retirements have not occurred with these plants. Furthermore, when the total accumulated difference at December 2022 is added to the unrecovered Sibley investment proposed by Evergy, the total difference is very close to the estimated unrecovered Sibley investment I have calculated at December 2022.[5]

Q WHAT DO THESE CALCULATIONS SHOW?

A Evergy has decreased the accumulated depreciation reserve balances for the Jeffrey Energy Center, Iatan 1 and 2, and Lake Road generating units to account for a portion of the undepreciated balance from the Sibley unit retirements. By doing so, Evergy will recover a portion of the unrecovered investment from the Sibley retirements in depreciation expense over the life of those generating units. Evergy will also collect a rate of return on those plants' decreased levels of accumulated depreciation reserves as proposed by Evergy. As I have explained earlier, the MECG is opposed to allowing a rate of return on the undepreciated investment resulting from the Sibley retirements. If the Commission also determines that a rate of return on the undepreciated investment in Sibley should not be allowed, it would need to make sure the entire undepreciated balance is included in the unrecovered balance. Failure to do so will result in a portion, in this case approximately $156 million, being allowed a rate of return for generating units that are not used and useful.

[5]$156,023,166 + $100,042,783= $256,065,949 compared with MECG proposed unrecovered investment of $254,454,796.

Q PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENTS FOR THE SIBLEY RETIREMENTS.

A I propose the following adjustments to Evergy's revenue requirement:

- Amortize the unrecovered investment in the Sibley units of approximately $254 million over 20 years. Twenty years was proposed by Evergy in its rate case.
- No rate of return allowed on the 20-year amortization of the unrecovered investment.
- Amortize the regulatory liability including rate of return of $142 million over ten years. Evergy proposed to amortize the regulatory liability over four years, but the total liability was significantly smaller.

Q ARE THERE ANY OTHER ADJUSTMENTS THAT NEED TO BE MADE REGARDING THIS ISSUE?

A Yes. The accumulated depreciation reserves that Evergy reduced to capture some of the unrecovered investment from the Sibley retirements need to be reinstated and new depreciation rates should be calculated for the Jeffrey Energy Center, Iatan 1 and 2, and Lake Road generating units. Reinstating those accumulated reserves should lower depreciation expense for those units.

Q HAVE YOU ESTIMATED THE IMPACT ON DEPRECIATION FOR THIS ISSUE?

A Yes. I have estimated that Evergy's steam production deprecation expenses will decrease by approximately $6.8 million.

Q HOW DO YOU RESPOND TO THE ARGUMENT THAT WAITING 20 YEARS FOR THE RECOVERY OF THE UNDEPRECIATED BALANCE FROM THE SIBLEY RETIREMENTS IS DETRIMENTAL TO THE SHAREHOLDERS OF EVERGY?

A Evergy has the option to securitize the unrecovered investment from the Sibley retirements and would receive those funds much sooner than 20 years. There are options available to Evergy to lessen the impact to shareholders. However, as I have stated before, Evergy ratepayers should not be required to provide a profit stream for retired generating units that are no longer providing service and are not used and useful.

IV. Missouri/Kansas Jurisdictional Allocations

Q PLEASE EXPLAIN THE JURISDICTIONAL ALLOCATIONS FOR METRO'S OPERATIONS.

A Metro's certificated service territory includes operations in both Missouri and Kansas. In order to develop a Missouri cost of service, the investments in Metro's operations need to be allocated between Missouri and Kansas. In this case, Metro is proposing to average the allocation factors presently used in Missouri (4CP - Coincident Peak) and Kansas (12 CP).

Q WHAT IS YOUR INITIAL THOUGHT ABOUT METRO'S PROPOSED JURISDICTIONAL ALLOCATION PROPOSAL?

A Here we go again, this is Deja Vu from the early 1980s.

Q ON PAGE 9 IN THE DIRECT TESTIMONY OF EVERGY METRO WITNESS JOHN WOLFRAM, HE DESCRIBES THE PAST USE OF ALLOCATION FACTORS. PLEASE RESPOND.

A I have included that piece of Mr. Wolfram's direct testimony.

> **Q HOW HAS THE DEMAND ALLOCATOR BEEN ADDRESSED IN PREVIOUS RATE FILINGS?**
>
> A In Missouri, prior to 1983, the Company allocated jurisdictional demand costs using 1 CP. Since then, in eleven different rate proceedings between 1985 and 2018, and given the numerous different proposals by the Company, Commission Staff, and intervenors in those cases, all of the Commission orders (in settled cases and otherwise) have implemented a Demand allocator in Missouri based on 4 CP.
>
> In the Kansas jurisdiction, the Company used a 7 CP Demand allocator prior to 1983. Since then, in ten different rate proceedings between 1985 and 2018, and again given numerous proposals by parties to those cases, all of the Kansas Corporation Commission ("KCC") orders (in settled cases and otherwise) have implemented a Demand allocator based on 12 CP.

What is missing from Mr. Wolfram's testimony is the fact that KCPL advocated for a 4 CP demand allocator for both its Missouri and Kansas jurisdictions in a KCPL rate case, Case NO. ER-85-128 and EO-85-185. The Missouri Commission agreed to implement the 4 CP methodology as compared to the 1 CP demand allocator supported by the Commission Staff.

Q WHAT INFORMATION ARE YOU RELYING ON TO SUPPORT THE ARGUMENT THAT KCPL ADVOCATED FOR USE OF A 4 CP ALLOCATOR AS A MEANS OF COMPROMISE BETWEEN THE MISSOURI AND KANSAS JURISDICTIONS?

A I was personally involved in those rate cases as a member of the Commission Staff. In addition, in the Commission's Report and Order in Case Nos. ER-85-128 and EO-85-185, the Commission stated the following:

> The Company asserts that 4 CP is the appropriate allocation method since it represents a compromise position between what it views as two extremes: the 1 CP approach taken by the Missouri Staff and the 12 CP approach taken by the Kansas Corporation Commission Staff. In addition, Company argues that 4 CP better reflects the duration of the Company's summer peak load resulting in costs allocation stability. Finally, KCPL asserts that the 4 CP method allocates non-fuel production costs without the need to classify those costs as demand or energy related.

The record is clear that the Commission adopted the 4 CP allocation method as a means to establish some consistency between Missouri and Kansas jurisdictions. However, as described in the testimony above, when it came time for the Kansas jurisdiction to adopt a 4 CP allocator, that argument was rejected in favor of a 12 CP allocator that maximized the benefits to the Kansas jurisdiction.

Q DOES MR. WOLFRAM ADDRESS THE APPROPRIATENESS OF THE 12 CP ALLOCATION METHOD PRESENTLY BEING USED IN THE KANSAS JURISDICTION?

A Yes. On pages 11-12, Mr. Wolfram discusses the FERC on- and off-peak test. The results of that FERC test reveal that the 12 CP allocator is not the appropriate allocator when relying on the FERC test. Specifically, Mr. Wolfram states on page 12 of his direct testimony;

> **Q DID YOU APPLY THE THREE FERC TESTS IN THIS CASE?**
>
> A Yes. I performed the tests using the test period demand data to compare 12 CP to several other CP demand scenarios: 1 CP, 3 CP using June, July, and August; 3 CP using July, August and September; 4 CP; 6 CP; 8 CP and 10 CP. I performed these tests for each Company jurisdiction (Missouri, Kansas, and wholesale) as well as for total. The analysis and results are provided in Schedule JW-2.

Q WHAT DO THESE TEST RESULTS INDICATE?

A The test results indicate that using a more seasonal peak determination is more appropriate than using 12 CP for determining the Demand allocator.

Q ARE YOU AWARE OF OTHER DEMAND ALLOCATION TESTS PERFORMED REGARDING THE MISSOURI/KANSAS JURISDICTIONAL ALLOCATOR?

A Yes. In KCPL's 2006 Missouri rate case, Case No. ER-2006-0314, Staff witness Erin Maloney filed direct testimony in that case. Part of Ms. Maloney's responsibilities in her direct testimony was to perform the FERC tests that Mr. Wolfram performed in the current rate case. Based on Ms. Maloney's FERC tests she concluded the following on page 10:

> The result of the first test (28%) falls within the above-indicated 26%-31% range of results that led to FERC decisions adopting a 4 CP methodology. The result of the second test (76%) is well below the range suggesting a 12 CP methodology (81%-88%) and just slightly below the 78%-81% range of results in the FERC decisions adopting a 4 CP methodology. The result of the third test (57%) falls within the 55%-60% range for which the FERC issued decisions adopting a 4 CP methodology. These tests support the usage of the 4 CP method.

I have attached a copy of the direct testimony filed by Staff witness Maloney in Case No ER-2006-0314 as Schedule GRM-1.

The FERC tests have been performed twice, spanning a time period of approximately 16 years, and both times the results indicate that the use of a 12 CP cannot be justified.

Q DO YOU SUPPORT THE PROPOSAL BY EVERGY TO AVERAGE THE RESULTS OF THE 4 CP (MISSOURI ALLOCATOR) AND THE 12 CP (KANSAS ALLOCATOR) FOR PURPOSES OF ESTABLISHING THE MISSOURI/KANSAS ALLOCATOR?

A Absolutely not. It has been shown on at least two instances that the use of the 12 CP is not an appropriate demand allocator for Evergy. Essentially, what Evergy is proposing is to ignore the appropriateness of the allocator and just average those together with the **hope** that Kansas will also adopt the proposed methodology. The Commission has gone through this exercise previously and the result was a failure as the Kansas jurisdiction ignored the compromise. Furthermore, it is simply unacceptable to use a flawed allocation methodology to determine a demand allocator. Essentially, Evergy is asking this Commission to ignore its statutory duty to set just and reasonable rates by adopting an averaging calculation based on a flawed allocator. Just and reasonable rates cannot be achieved under this scenario. Therefore, MECG would propose to maintain the 4 CP methodology for this rate case.

Q DO YOU HAVE ANY SUGGESTIONS TO EVERGY CONSIDERING ITS CONCERNS WITH THE DEMAND ALLOCATOR?

A Yes. I would suggest that Evergy pursue the appropriate demand allocator in Kansas. It has been shown that the 4 CP allocator is the more appropriate demand allocator. Evergy needs to present compelling evidence to the KCC to convince them that the movement to the 4 CP will result in just and reasonable rates. Trying to get Missouri to buy into the use of a bad allocation methodology is hardly the answer to establishing just and reasonable rates. Missouri compromised before and it did not result in a comprehensive multi-jurisdictional allocator. The present Missouri demand allocator is proven and should be used for all jurisdictions for the Metro operations.

V. Bad Debt and Property Tax Trackers

Q IS EVERGY REQUESTING NEW TRACKERS IN THIS RATE CASE?

A Yes. Evergy is requesting Commission approval of a bad debt expense and property tax tracker in this rate case.

Q DO YOU SUPPORT THESE TRACKERS?

A No. I am opposed to the implementation of both trackers.

Q WHAT PERCENT OF TOTAL OPERATING EXPENSES DOES BAD DEBTS REPRESENT IN EVERGY'S CURRENT RATE CASE?

A For Metro's operations, bad debts expense represents 1.11% of the total operating expense that Metro is requesting in this rate case.[6] For West operations, bad debts expense represents 0.87% of total operating expenses that West is requesting in this rate case.[7] Clearly, both totals represent a very small portion of the operating expenses for Evergy.

Q IS THIS THE TRUE IMPACT THOUGH OF THE REQUESTS FOR THESE TRACKERS?

A No. The trackers would track cost differences between cost levels established in a rate case and actual expenses incurred. In almost all instances, the impacts to the expense will be much less than what was previously discussed. In other words, the change in bad debts will in all likelihood be significantly less than the 1.11% of expenses. This comparison was performed to highlight the insignificance of these expenses to the total

[6]$10,114,679 (bad debts) / $915,186,712 (total operating expenses) - Metro's cost of service.
[7]$6,003,109 (bad debts) / $690,511,190 (total operating expenses) - West's cost of service.

cost of service and highlight the insignificant change that would occur in total operating expenses from these trackers.

Q WHAT JUSTIFICATION DID EVERGY PROVIDE FOR THE NEED OF A BAD DEBT EXPENSE TRACKER?

A Evergy witness Darren Ives discusses the need for a bad debt expense tracker. Mr. Ives testifies that a bad debt expense tracker would lessen the exposure that the elevated accounts receivable balances remaining on Metro's books will result in significantly higher bad debt expense in future periods than will be established in rates in this rate case. In other words, Evergy needs a bad debt expense tracker if the higher accounts receivable balances translate into higher bad debt expenses in the future. I do not believe a tracker for bad debt expenses should be established in anticipation of a future event that may not occur. This request simply goes beyond the test year and true-up period in this rate case. The request also begs the question of a known and measurable event. Mr. Ives testimony clearly states that the tracker is needed for a potential situation in the future. There is nothing in his explanation that would qualify his request based on known and measurable situations. The bad debt tracker is being proposed on mere speculation of the future.

Q ARE YOU AWARE OF OTHER SPECIAL REGULATORY TOOLS THAT EVERGY HAS THAT PROTECTS SHAREHOLDERS FROM EARNING EROSION?

A Yes. MECG submitted Data Request No. 4-4 that asked Evergy to confirm the existence of certain special regulatory tools that it has available. Evergy confirmed it had the following special regulatory tools available:

- Fuel adjustment clause ("FAC") that allows it to collect increases in its fuel expense in between rate cases;

- Pension tracker that allows Evergy to track pension expenses to be recovered in Evergy's next rate case;
- Other Post Employment Benefits ("OPEB") tracker that allows Evergy to track OPEB expenses in between rate cases to be recovered in Evergy's next rate case;
- Evergy has elected to participate in PISA (Plant in Service Accounting) that allows deferral of 85% of plant investment costs in between rate cases. Specifically, PISA allows for the deferral of depreciation expenses and return on PISA qualified investment. The deferred balance is included in rates in Evergy's next rate case.
- Evergy West has a RESRAM (Renewable Energy Standard Rate Adjustment Mechanism) that allows rates to be changed outside of a rate case. Evergy Metro does not have a RESRAM, but has a tracking mechanism with deferral of costs for Metro that it can request recovery through amortization in a rate case.
- Evergy has the ability to change rates in between rate cases for the collection of Missouri Energy Efficiency Investment Act ("MEEIA") costs.
- Evergy has the ability to file for securitization of certain costs in between rate cases.
- Evergy is allowed to accrue AFUDC (Allowance for Funds Used During Construction) on plant construction projects.

These special regulatory tools available to Evergy would address a significant amount of Evergy's operating expenses and capital cost recovery.

Q DO YOU BELIEVE THAT A TRACKER OR RIDER INCENTS A UTILITY TO CONTROL COSTS?

A No, I do not. I believe a tracker reduces the Utility's incentive to control costs. The Commission shared my concern in its Order in Case No. ER-2014-0258, where the Commission stated:

> 8. Tracker mechanisms can be a useful tool in the correct circumstances, but they should be used sparingly because they can reduce the incentive of the utility to closely control its costs. (Report and Order, May 12, 2015, page 50, Footnote omitted)

Further, in the Commission Order addressing a storm tracker, the Commission stated:

> 8. By their nature, cost trackers tend to reduce a utility's incentive to aggressively control costs by ensuring that all costs will be recovered. Under a tracker, such costs would be subject to a prudence review, but a prudence review cannot control costs as efficiently as a strong economic incentive. (Report and Order, May 12, 2015, page 45, Footnote omitted).

Q PLEASE SUMMARIZE WHY YOU ARE OPPOSED TO THE BAD DEBT EXPENSE TRACKER.

A Evergy already has several special regulatory tools to protect itself from earnings erosion. A bad debt tracker is not necessary given the small fraction of costs that it would protect. By allowing a bad debt tracker, the Commission would be reversing its correctly stated position from its Order in Case No. ER-2014-0258. Furthermore, as Mr. Ives stated, the request for this bad debt expense tracker is more directed to future events that may not occur. The request for a bad debt expense tracker that is being proposed is not based on known and measurable events.

Q WHY IS EVERGY SEEKING A PROPERTY TAX TRACKER?

A Evergy witness Darren Ives discusses certain reasons why the Commission should adopt a property tax tracker. I have listed those reasons below:

- The Company expects to continue incurring significant regulatory lag due to increasing property taxes, which in turn impacts the Company's ability to earn returns reasonably close to the return authorized by this Commission.
- Property taxes determined by Missouri state assessors are a significant component of the Company's cost of service, and amounts assessed are out of the control of the Company to manage.

Q DO YOU RELY ON YOUR PREVIOUS ARGUMENTS AGAINST A BAD DEBT TRACKER AS REASONS WHY THE PROPERTY TAX TRACKER SHOULD BE DENIED?

A Yes, I do.

Q DO YOU HAVE ANY FURTHER COMMENTS ON THIS ISSUE?

A Yes. Mr. Ives cites the inability of Evergy to control the costs of property taxes. Although I would generally agree with Mr. Ives, I would point out that Evergy has the ability to appeal its property tax assessments. Therefore, if Evergy feels it is being overcharged property taxes, it is Evergy's duty to file tax appeals on behalf of its ratepayers.

I would also like to comment on the argument that these costs are uncontrollable and therefore need to be tracked. I have heard this argument on several occasions, especially in the area of fuel expense when utilities were seeking FACs. I would like to point out that there are solutions to the uncontrollable nature of expenses by planning rate case filings to capture those costs, or by structuring payment terms such that the cost fluctuations occur at a predictable interval.

Prior to passage of legislation allowing an FAC for electric utilities, Ameren Missouri negotiated fuel and transportation contracts so that the annual contract escalations would occur on about the same timeframe (January 1). In this way, Ameren Missouri was able to file rate cases to timely recover fuel cost escalations. Although it was claimed that fuel expense increases were outside the control of Ameren Missouri, Ameren Missouri was able to have the fuel cost increases occur such that it could timely file rate cases to recover those costs.

In the area of property taxes, Metro pays property taxes mainly in Missouri and Kansas. The Missouri payments of those property taxes are due before December 31 of the current year. Kansas property taxes are due on two payment dates, December 20 and May 10. If half of the Kansas taxes are not paid by December 20, then the whole amount is due at that point in time. For West's operations, property taxes are predominantly paid to Missouri. The statutory date (December 31) for payment of Missouri property taxes dates back to 1945 and the statutory dates for payment of Kansas property taxes dates back to 1876. Clearly, these tax payment dates have been known and measurable for many decades. The predominance of Evergy's property taxes are due in December. Evergy has the ability to file timely rate cases to seek any increases in its property taxes without the need for a tracker.

In summary, I want to emphasize that the uncontrollability of expenses should include an analysis if a utility has the ability to address those expense changes in a timely manner (e.g., Ameren Missouri fuel and transportation contracts) or if those expenses are due for payment such that timely rate case recovery is possible. However the overriding reason for the rejection for these proposed trackers is that they do not represent a material percentage of the operating expenses of Evergy.

VI. Storm Reserves

Q HAVE METRO AND WEST PROPOSED A STORM RESERVE FOR THIS RATE CASE?

A Yes. In addition to the property tax tracker and bad debt expense tracker, Evergy is also requesting a storm reserve. The storm reserve would be for collection of non-labor storm costs in excess of $200,000 per storm.

Q WHY HAVE YOU INCLUDED EVERGY'S REQUEST FOR A STROM RESERVE WITH THE PROPERTY TAX TRACKER AND BAD DEBT EXPENSE TRACKER?

A All of these special regulatory tools will essentially track expenses in between rate cases.

Q ARE YOU OPPOSED TO THE STORM RESERVE?

A Yes. The arguments against the storm reserve are very similar to the arguments I have previously stated for my opposition to the property tax tracker and bad debt expense tracker. Adopting a storm reserve would also be contrary to the Commission Order I quoted earlier emphasizing that trackers should be used sparingly.

Q PLEASE DESCRIBE HOW THE STORM RESERVE WOULD WORK.

A Ratepayers would be required to pay in advance for a reserve that is essentially a fund to address future storms. When a storm occurs, Evergy would simply draw down funds from the storm reserve to make the repairs necessary for repairing damage caused by the storm. Essentially, a storm reserve requires customers to pay for storm repairs in advance.

Q BESIDES THE ARGUMENTS YOU MADE EARLIER FOR YOUR OPPOSITION TO THE PROPERTY TAX TRACKER AND BAD DEBT EXPENSE TRACKER, DO YOU HAVE OTHER ARGUMENTS FOR YOUR OPPOSITION TO A STORM RESERVE?

A Yes. Evergy has not produced sufficient evidence to justify a storm reserve. I am aware of storm reserves in the states of Florida and Louisiana, where storm damage can reach hundreds of millions of dollars. However, in the Evergy service area, storm costs over $200,000 are not a major cost of service. I have prepared Table 7 that shows the frequency of storms from 2011-2021 for both Metro and West operations.

TABLE 7

Frequency of Storms
Over $200K - Non-Labor

Year	Metro	West
2011	0	0
2012	0	0
2013	3	1
2014	6	0
2015	3	0
2016	1	0
2017	3	0
2018	3	1
2019	4	3
2020	0	1
2021	5	6
Total	28	6

Table 7, above, highlights the infrequent nature of storms, especially for the West operations.

However, even more convincing is the cost impact from the individual storms. I have prepared Table 8 that shows the cost per storm for those reported storms.

TABLE 8

<u>Cost per Storm</u>

Cost Range	Metro	West
Over $1.5 Million	1	0
$1 Million to $1.5 Million	2	0
$500K - $1 Million	2	3*
$400K - $500K	3	0
$300K - $400K	7	2
$200K - $300K	13	1
Total	28	6

*These storm costs were between $500K and $600K

When the storm costs are broken down to the cost per storm, the history of storm costs shows that these storms are not creating a significant impact on the operations of either Metro or West. I would note that the total operating expenses from Metro operations is $915 million and $691 million for West operations. As Table 8, above, shows, the majority of the individual storms cost between $200K to $400K. These individual storm costs are not significant when compared to the total operating expenses of both Metro's and West's operations.

Q IN HIS DIRECT TESTIMONY, MR. KLOTE STATES THAT THE UTILITIES' FOCUS AND NUMBER ONE PRIORITY AT THE TIME OF SIGNIFICANT STORMS SHOULD BE IN RESTORING CUSTOMER SERVICES THAT HAVE BEEN IMPACTED BY OUTAGES. PLEASE RESPOND.

A I totally agree with Mr. Klote that service restoration should be the number one priority in addressing storm restoration efforts. However, a storm reserve would not lessen the time for storm restoration. MECG submitted Data Request No. 4-1 that asked if a storm reserve would lessen the time it takes to restore service. Evergy responded saying the proposed storm reserve would not lessen the time it takes to restore service for customers. I have attached as Schedule GRM-2 a copy of that data request and response.

Q DID MR. KLOTE PROVIDE OTHER REASONS WHY A STORM RESERVE SHOULD BE IMPLEMENTED?

A Yes. Mr. Klote stated that a storm reserve would be beneficial for both customers and shareholders by providing rate stability for customers and earning stability for shareholders. He also indicates that neither benefit is currently missing from the current operations of Metro and West. As I have previously discussed, the cost impact from storms is not a significant amount when compared to total operating expense. In addition, customer rate stability will not be adversely affected by continuing to pay for storms as they occur through the normal ratemaking process, where a certain level of storm costs are included in rates at each rate case. Similarly, the effect on shareholder earnings is minimal at best given the recent scale of storm costs on the operations of Metro and West.

Q ARE THERE ANY OTHER SPECIAL REGULATORY TOOLS AVAILABLE TO EVERGY IF STORM COSTS ARE EXCESSIVE IN A YEAR?

A Yes. Metro and West always have the option to file for an AAO to address storm costs if they feel the extraordinary nature of those costs would negatively impact its earnings. Mr. Klote recognizes that it has the opportunity seek an AAO for storm costs recovery. On page 39 of his direct testimony Mr. Klote states:

> The implementation of this reserve will be used to cover intermediate to large storms by using a $200,000 minimum storm level, but in the event a storm is very significant and impactful to Company operations this request does not preclude the Company from requesting an Accounting Authority Order if the magnitude of the storm warrants the request as has been done historically.

Q PLEASE SUMMARIZE MECG'S POSITION ON THE PROPOSED STORM TRACKER?

A MECG is opposed to implementing a storm reserve. A storm reserve is very similar in nature to a tracker and this Commission has expressly stated its concerns about excessive use of trackers. A storm reserve would require ratepayers to pay in advance for storms yet to occur. The best process to address storm cost recovery is through the normal ratemaking process wherein all relevant factors for Metro and West operations can be reviewed at the same time. Rate stability and earnings stability are not valid arguments for the storm reserve as the impact from storms has not been a significant event for Metro and West operations. Evergy already has enough special regulatory tools to protect its earnings base. In fact, if storms do cause a significant impact on its earnings, it can seek to use the special regulatory tool, an AAO if it meets the criteria.

VII. Nuclear Depreciation

Q DID METRO REQUEST THAT NUCLEAR DEPRECIATION EXPENSES BE INCREASED FOR THIS RATE CASE?

A Yes. Metro has requested that the Wolf Creek depreciation expense be increased by approximately $5.5 million or approximately 29%.

Q DO YOU SUPPORT THE INCREASE BEING PROPOSED BY METRO?

A No.

Q PLEASE PROVIDE YOUR RATIONALE FOR OPPOSING THE INCREASE IN WOLF CREEK DEPRECIATION EXPENSE.

A Wolf Creek generating unit is a vital aspect of the Metro generating fleet. Given its costs, the unit should operate as long as possible. In these times of significant retirements of coal units, a nuclear baseload unit becomes even more valuable to a utility.

Wolf Creek generating unit was designed identically to Ameren Missouri's Callaway nuclear generating plant with the one exception that Wolf Creek operates with a cooling pond and Callaway has a cooling tower. Ameren Missouri has already indicated its intentions to seek license extension when its operating license expires in 2044. Given Wolf Creek's operating history and the importance to the Evergy generation mix, there is no logical reason why Wolf Creek should also not seek license extension.

Q IF LICENSE EXTENSION IS SOUGHT, WHAT TIME PERIOD WOULD BE INVOLVED IN THE EXTENSION REQUEST AND WHAT WOULD THAT MEAN FOR DEPRECIATION EXPENSE?

A I would assume that another 20-year term would be sought for life extension. When life extension is granted, Wolf Creek would have another 20 years to recover depreciation expense on the generating unit.

Q YOU MENTIONED EARLIER WOLF CREEK'S OPERATING HISTORY. PLEASE EXPAND ON THAT STATEMENT.

A I have performed a comparison of the operating history of the Callaway and Wolf Creek generating units over the last ten years (2012-2021). Wolf Creek had a greater amount of net generation produced during the 10-year term despite having a lower operating capacity (1295 MW-Callaway, 1255 MW-Wolf Creek). Wolf Creek had a higher capacity factor over the 10-year period (81%-Callaway, 82.5%-Wolf Creek). Finally, Wolf Creek has a higher availability rate compared to Callaway (84%-Callaway, 85.2%-Wolf Creek).

Given the performance of Wolf Creek compared to Callaway and Ameren Missouri's announcement to seek life extension, it seems logical that Evergy will also seek life extension of Wolf Creek. Therefore, it is inappropriate at this time to request an increase in Wolf Creek depreciation expenses. Increasing Wolf Creek's depreciation expense at this time is simply premature and may require existing ratepayers to pay excessive depreciation charges. Therefore, I recommend that the existing Wolf Creek depreciation rates be used for Metro's cost of service.

VIII. Labor Expenses

Q DID EVERGY METRO AND WEST INCLUDE ANY PAYROLL EXPENSES IN ITS COST OF SERVICE FOR THE RECOVERY OF SEVERANCE PAYMENTS?

A No. MECG submitted Data Request Nos. 2-14 and 2-15 to verify that Metro and West cost of service calculations did not contain any expenses associated with severance payments. In response to MECG Data Request Nos. 2-14 and 2-15, Metro and West confirmed that no severance payments were included in cost of service.

Q WHY IS THE ELIMINATION OF SEVERANCE COSTS FROM COST OF SERVICE NECESSARY?

A An analysis would need to be performed to show that the savings in total payroll costs from an employee that no longer works for Evergy would not cover the costs of severance. In many instances, the labor savings from an employee no longer working for Evergy outweighs the severance costs paid to that employee. If severance costs are included in cost of service, ratepayers would end up paying for labor dollars that no longer exist and paying to sever the employee. Clearly, this situation would require ratepayers to pay excessive labor expenses.

Q IS THERE ANY OTHER ASPECT OF EVERGY'S LABOR ADJUSTMENT THAT CONCERNS MECG?

A Yes. In determining a normalized level of overtime, I feel that Metro and West have overstated the level of overtime dollars to be included in cost of service.

Q WHAT IS THE HISTORICAL LEVEL OF OVERTIME COSTS AND THE AMOUNTS INCLUDED IN METRO AND WEST'S COST OF SERVICE?

A I have prepared Table 9 that shows the historical levels of overtime dollars expensed by Metro. It should be noted that all payroll transactions are generated from the Metro operations. Labor costs are then allocated to the other operating division (West).

TABLE 9

Historical Levels of Overtime Dollars

Period	Overtime Dollars	Averages
2018	$32,507,021	4 Year - $31,872,695
2019	$31,294,180	3 Year - $31,991,239
2020	$29,791,656	2 Year - $31,844,769
2021	$33,897,882	
Rate Case	$34,808,110	

Clearly, the level of overtime dollars is excessive when compared with the historical levels of overtime. I would also note that the level of overtime dollars included in the rate case was developed from a three-year average of overtime dollars factored up by 2.5% each year to attempt to replicate current payroll dollars.

Q. ARE YOU IN AGREEMENT WITH FACTORING-UP OVERTIME DOLLARS?

A No. As can be seen from Table 9, the level of overtime dollars fluctuates slightly from year to year. There is no trend in overtime dollars. In fact, it could be argued that overtime dollars have stabilized at approximately $31.8 million per year.

Q WHAT IS YOUR PROPOSED LEVEL OF OVERTIME COSTS FOR COST OF SERVICE?

A I would propose that the total level of overtime costs be $31.9 million. This level would then need to be allocated to Metro and West operations. I would also propose that if my level of overtime dollars is not adopted by the Commission, that the Commission reject Evergy's factoring-up procedure to annualize overtime costs. Evergy has not provided any analysis why factoring-up overtime dollars is necessary in these circumstances.

Q DO YOU HAVE ANY OTHER CONCERNS WITH EVERGY'S PAYROLL ADJUSTMENT?

A Yes. Evergy calculated a pay increase of 2.5% for all base payroll dollars. From that total, Evergy adjusted payroll assigned to Joint Owners of approximately $17 million. The $17 million total was subtracted from the base payroll dollars that had already been escalated for the 2.5% payroll increase. Essentially, Evergy's base payroll assigned to Metro and West operations contain an escalation for payroll assigned to the Joint Owners. I disagree with this portion of the payroll annualization proposed by Evergy. I believe this lowers payroll expense by $400K-$500K.

Q DOES THIS CONCLUDE YOUR CONCERNS WITH EVERGY'S PAYROLL ADJUSTMENTS?

A Yes, it does.

IX. Property Tax Expense

Q WHAT LEVEL OF PROPERTY TAXES ARE INCLUDED IN EVERGY'S METRO AND WEST COST OF SERVICE CALCULATIONS?

A Evergy has proposed to include an estimated property tax level for payment due on December 31, 2022. Evergy has proposed to include an estimated property tax level that is a full seven months beyond the true-up period of May 31, 2022. This is clearly not a known and measurable change to set just and reasonable rates.

Q WHAT WOULD YOU PROPOSE TO INCLUDE AS PROPERTY TAX EXPENSE IN THIS RATE CASE? PLEASE PROVIDE YOUR JUSTIFICATION.

A I would propose that the actual property taxes paid on December 31, 2021 be used to set rates in the Metro and West rate cases. These levels of property taxes have been paid and are known and measurable in the context of this rate case. As I have previously stated, property taxes are due and payable for the most part in December every year (December 31 for Missouri and December 20 for Kansas). If property taxes represent such a large expense to Evergy, it should have timed its rate case to better reflect more current property taxes. Asking for increased property taxes due seven months beyond the true-up in this case does not reflect an all-relevant factor review of operations by Evergy and, therefore, Evergy's adjustment should be denied. Furthermore, the historical increases in property taxes claimed by Evergy have been paid by Evergy and it still has earned its authorized rate of return.

X. Federal Income Tax

Q DID EVERGY REQUEST THAT EACH OF ITS COST OF SERVICE FILINGS REFLECT ANY KNOWN FEDERAL CORPORATE INCOME TAX RATE CHANGE?

A Yes. Evergy witness Melissa K. Hardesty filed direct testimony in both the Metro and West rate cases. In that testimony, on page 10, Ms. Hardesty requested that:

> …if Congress does enact new legislation that would increase or decrease the federal corporate tax rate before the true-up period in this case, the company requests that any impact of the rate change when enacted and any amortization of any new deficient or excess deferred taxes generated be included as an adjustment in this case.

Q DO YOU AGREE WITH THE POSITION ADVOCATED BY MS. HARDESTY?

A I would agree that if a Federal Corporate Income Tax rate change would occur before the true-up in this rate case, that the effect of that tax rate change on the current income tax payable needs to be included in the true-up cost of service calculations. I am not in support of Ms. Hardesty's position that all possible effects need to be addressed in these rate cases. The effects on Accumulated Deferred Income Taxes may not require immediate rate relief and could be addressed during future rate cases. In the context of this issue, it is simply too early to address the ramifications from a Federal Corporate Income Tax rate change until the entire tax legislation is known and measurable.

XI. Crossroads Energy Center ("Crossroads")

Q PLEASE DESCRIBE CROSSROADS.

A Crossroads is a generating station located in Clarksville, Mississippi over 500 miles from the West service area. Crossroads is a peaking unit consisting of four combustion turbines. Crossroads is located in the Midcontinent Independent System Operator ("MISO") footprint, while the West service area is located in the Southwest Power Pool ("SPP") footprint.

Q WHAT IS THE RELEVANCE OF CROSSROADS BEING LOCATED IN A DIFFERENT REGIONAL TRANSMISSION ORGANIZATION ("RTO") THAN THE WEST SERVICE AREA?

A RTOs typically provide two types of transmission service: (1) network service; and (2) point-to-point service. Network service allows the purchaser to transmit energy anywhere within the RTO. Thus, if Crossroads was located in SPP, that energy could be delivered to the West service area within SPP through network service. Since

Crossroads is located in MISO, West is required to purchase point-to-point service from MISO to get the energy from Crossroads to the SPP footprint.

Q HAS THE COMMISSION PREVIOUSLY ADDRESSED THE RECOVERY OF TRANSMISSION COSTS ASSOCIATED WITH CROSSROADS?

A Yes. GMO first sought to include Crossroads' transmission costs in its 2010 rate case, Case No. ER-2020-0356. In that case, the Commission held that:

> It is not just and reasonable to require ratepayers to pay for the added transmission costs of electricity generated so far away in a transmission constricted location. Thus the Commission will exclude the excessive transmission costs from recovery in rates. (Report and Order, Case No. ER-2010-0356, page 87).

In GMO's 2012 case, GMO again sought recovery of the transmission costs from Crossroads. In that case, the Commission made the following decision:

> GMO asks the Commission to depart from the previous rulings and include in MPS rates the costs of transmitting power from Crossroads to MPS territory but it has not carried its burden of proof on that claim…. The high cost of transmission is not outweighed by lower fuel costs in Mississippi…
>
> …. Therefore the Commission concludes that including the Crossroads transmission costs does not support safe and adequate service at just and reasonable rates, and the Commission will deny those costs. (Report and Order, Case No. ER-2012-0175, pages 58-59)

In Case No. ER-2016-0156, GMO once again sought recovery of Crossroads' transmission costs. In that case though, GMO entered into a settlement that explicitly disallowed all transmission costs associated with Crossroads.

> The costs and revenues in GMO's FAC will not include transmission costs associated with Crossroads Energy Center and will be consistent with those in Kansas City Power & Light Company's current FAC, with two exceptions. (Non-Unanimous Stipulation and Agreement, Case No. ER-2016-0156, page 13).

Q IN THE CURRENT CASE, HAS WEST PROPOSED RECOVERY OF THE CROSSROADS TRANSMISSION EXPENSES IN ITS COST OF SERVICE?

A No. West has proposed adjustment CS-45 to remove the test year transmission expenses for Crossroads.

Q HAVE YOU COMPARED THE DISALLOWED AMOUNT TO PREVIOUS RATE CASE DISALLOWANCES AND PAST YEARS CROSSROADS' TRANSMISSION EXPENSES?

A Yes. I have compared the disallowed transmission expenses projected from January-May 2022 data to the historical disallowances from previous rate cases and the transmission expense totals recorded annually for 2019-2021. The proposed disallowance of the Crossroads transmission expenses appear reasonable for this rate case.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

<u>Qualifications of Greg R. Meyer</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and investigations, including staffing decisions, and in the development of staff positions in which the Auditing Department was assigned. I served as Lead Auditor and/or Case Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Florida, Idaho, Illinois, Indiana, Iowa, Maryland, Missouri, New Mexico, Utah, Washington, Wisconsin and Wyoming. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. In addition, I have filed testimony at the Federal Energy Regulatory Commission ("FERC"). These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

Exhibit No.:	
Issues:	System Energy Losses Demand and Energy Jurisdictional Allocation
Witness:	Erin L. Maloney
Sponsoring Party:	MO PSC Staff
Type of Exhibit:	Direct Testimony
Case No.:	ER-2006-0314
Date Testimony Prepared:	August 8, 2006

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

ERIN L. MALONEY

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

Jefferson City, Missouri
August 2006

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan	)))))	Case No. ER-2006-0314

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the following Direct Testimony in question and answer form, consisting of 11 pages of Direct Testimony to be presented in the above case, that the answers in the following Direct Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

E. L. Maloney
Erin L. Maloney

Subscribed and sworn to before me this 7th day of August, 2006.

ROSEMARIE RIEDL
MY COMMISSION EXPIRES June 1, 2009
NOTARY SEAL
#05509538
COLE COUNTY
NOTARY PUBLIC, STATE OF MISSOURI

Rosemarie Riedl
Notary Public

My commission expires June 1, 2009

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DIRECT TESTIMONY

OF

ERIN L. MALONEY

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2006-0314

DIRECT TESTIMONY

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KANSAS CITY POWER AND LIGHT COMPANY

CASE NO. ER-2006-0314

Q. Please state your name and business address.

A. Erin L. Maloney, P.O. Box 360, Jefferson City, Missouri, 65102.

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

A. I am employed by the Missouri Public Service Commission (Commission) as a Utility Engineering Specialist II in the Energy Department of the Utility Operations Division.

Q. Please describe your educational and work background.

A. I graduated from the University of Nevada - Las Vegas with a Bachelor of Science degree in Mechanical Engineering in June 1992. From August 1995 through November 2002, I was employed by Electronic Data Systems of Kansas City, Missouri, as a System Engineer. In January 2005, I joined the Commission Staff (Staff) as a Utility Engineering Specialist I.

Q. Have you previously filed testimony before the Commission?

A. Yes. I filed testimony on reliability in Case No. ER-2005-0436 and I filed testimony on system losses and jurisdictional allocation in Case No. ER-2006-0315.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to present information and make recommendations on the following three issues:

(1) System Energy Losses

(2) Jurisdictional Demand Allocation

(3) Jurisdictional Energy Allocation

EXECUTIVE SUMMARY

Q. Please summarize your analysis, results, and recommendations.

A. **(1) System Energy Losses**

I calculated the total company system energy losses to be 5.32% of the total electrical system inputs (i.e., Net System Input or NSI) for the test year using the methods described in this testimony. I then compared my results to the overall system loss calculated in Kansas City Power and Light Company's (KCP&L or Company) most recent loss study (5.34%). I reviewed and verified the Company's loss study and I recommend that Staff adopt the system and class load losses determined in that study.

(2) & (3) Demand and Energy Jurisdictional Allocation

I calculated the jurisdictional allocation factors for demand using a Four Coincident Peak (4 CP) methodology. The calculated demand factors are as shown in the Table 1. Table 1 also shows the jurisdictional allocation factors for energy. The energy allocation factors were calculated after applying adjustments for large customer annualization, weather normalization, and customer growth.

Table 1 Demand and Energy Jurisdictional Allocation Factors

	Missouri Retail	Kansas Retail	Wholesale
Demand	**.5346**	**.4573**	**.0082**
Energy	**.5668**	**.4243**	**.0089**

SYSTEM ENERGY LOSS FACTOR

Q. What is the result of your system energy loss factor calculation?

A. As shown on Schedule 1, attached to this Direct Testimony, the calculated overall system energy loss factor is 0.0532 while the loss factor resulting from KCP&L's loss study was 0.0534. Staff is recommending that the Company's loss study results including the class load loss factors be adopted.

Q. What is the 'System Energy Loss Factor'?

A. The system energy loss factor is the ratio of system energy losses to Net System Input (NSI):

System Energy Loss Factor = System Energy Losses ÷ NSI

Q. What are system energy losses?

A. System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) in the utility's system between the generating sources and the customers' meters. In addition, small, fractional amounts of energy either stolen (diversion) or not metered are included as system energy losses.

Q. Why is it important to determine system energy losses?

A. The utility must know how much energy is being lost in the system in order to plan enough generation to meet forecasted peak load demands while compensating for losses.

Q. How are system losses determined?

A. The overall system losses are the difference between the metered inputs to the electrical system and the metered outputs to the electrical system. The inputs to the electrical system are the net generation, net interchange of energy, and any inadvertent flow and can be expressed mathematically as:

NSI = Net Generation + Net Interchange + Inadvertent Flows

The outputs of the system, also known as NSI, are the energy sold, energy used by the company, and the system energy losses. This can be expressed mathematically as:

NSI = Total Sales + Company Use + System Energy Losses

Q. How are 'Total Sales' and 'Company Use' output values determined?

A. Total Sales includes all of the Company's retail and wholesale sales of energy. Company Use is the electricity consumed at the Company's non-generation facilities, such as its corporate office building in Kansas City, Missouri. Total Sales data was provided by KCP&L in response to Staff Data Request No. 182. Company Use data was provided by KCP&L in response to Staff Data Request No. 183.

Q. How are the inputs to the electrical system determined?

A. As noted earlier, the inputs to the Company's electrical system are the sum of KCP&L's net generation, net interchange, and any inadvertent flows. Net interchange is the difference between interchange purchases and off-system sales. Net generation is the total energy output of each generating station minus the energy consumed internally to enable its production. The output of each generating station is monitored continuously, as is the net of off-system purchases and sales. The information I used was obtained from data supplied by KCP&L in response to Staff Data Request Nos. 184 and 74. The difference between scheduled and actual flows on a system is termed inadvertent interchange. This information was provided on a monthly basis in KCP&L's response to Staff Data Request No. 189.

Q. Why are you recommending that the system and class load losses determined in the Company's loss study be used?

A. The study uses the same method to calculate the overall system losses as I did. The study then goes on to determine losses at the transmission, substation, distribution primary, and distribution secondary service levels using engineering methods and estimates. I was able to verify the KCP&L control area as well as the electrical equipment which makes up the KCP&L system used in the study. Next, I verified the soundness of the engineering methods used to determine loss factors at the various service levels. These various service levels ultimately define the various classes.

Q. Are there additional advantages to using the class load loss factors resulting from the Company's study?

A. Yes. Using class load losses is a more accurate depiction of the actual energy losses occurring at the various voltage levels at the transmission, substation, and distribution primary and secondary service levels (classes).

JURISDICTIONAL ALLOCATION

Q. Please define the phrase "jurisdictional allocation".

A. For purposes of this testimony, jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri retail operations, Kansas retail operations and Wholesale operations. The particular allocation factor applied is dependent upon the types of costs being allocated.

DEMAND ALLOCATION FACTORS

Q. What are the demand allocation factors that you are recommending be used in this case?

A. As shown on Schedule 2 attached to this direct testimony, the calculated demand allocation factors for the test year are as follows:

Missouri Retail	**.5346**
Kansas Retail	**.4573**
Wholesale	**.0082**

Q. What is the definition of demand?

A. Demand refers to the rate at which electric energy is delivered to or by a system, generally expressed in kilowatts (kW) or megawatts (MW), either at an instant in time or averaged over a designated interval of time that is typically one hour or less.

Q. What types of costs are allocated on the basis of demand?

A. Capital costs associated with generation and transmission plant and certain operational and maintenance expenses are allocated on this basis. This is appropriate for these expenditures because generation and transmission are planned, designed and constructed to meet anticipated demand.

Q. What methodology did the Staff use to determine the demand allocation?

A. A methodology known as the four coincident peak (4 CP) methodology was used.

Q. What is meant by the four coincident peak methodology?

A. The term coincident peak refers to the load of each jurisdiction that coincides with the hour of the Company's overall system peak. A 4 CP methodology refers to utilizing the recorded peaks in each of the four (4) peak summer months of the selected test year.

Q. Why use peak demand as the basis for allocations?

A. Peak demand is the largest electric load requirement occurring on a utility's system within a specified period of time (e.g., day, month, season, or year). Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.

Q. Please describe the procedure for calculating the jurisdictional demand allocation factors using the 4 CP methodology.

A. The allocation factor for each jurisdiction was determined using the following process:

a) The peak hourly loads in the summer months of June, July, August, and September of calendar year 2005 for each jurisdiction were identified and summed.

b) The total peak hourly loads for the summer months of June, July, August, and September of calendar year 2005 were summed for all jurisdictions.

c) The sum for the summer months calculated in (a) was divided by the total sum calculated in (b) for each jurisdiction. This resulted in the allocation factor for each jurisdiction. The sum of the demand allocation factors across all jurisdictions equals one.

Q. How was the decision made to recommend using the 4 CP method?

A. The 4 CP methodology is appropriate for a utility, such as KCP&L, where the monthly peak demands during the non-summer months are significantly below the summer monthly peak demands. The lower demand in the non-summer months will have little or no influence on the capacity planning process and it would not be rational to consider all twelve monthly peaks in a jurisdictional allocation methodology when there are such significant statistical variations in the monthly seasonal peaks.

Q. Is there additional support for the position that a 4 CP methodology is appropriate in this case?

A. Yes. In various cases, the Federal Energy Regulatory Commission (FERC) has, among other things, used a number of tests as a guide in its determination of an appropriate demand methodology. These tests are arithmetical calculations whose results I compared to specific ranges determined from prior FERC decisions which suggest which methodology is more appropriate. Attached to this testimony as Schedule 3 is an excerpt (Chapter 5) from a publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers," Third Edition (1994), authored by Michael E. Small. As this excerpt shows, FERC has used these tests to support its adoption of a 4 CP methodology in a number of cases.

Q. Please describe the FERC tests you used in your selection of a CP methodology.

A. The following tests included in the aforementioned guidelines (attached as Schedule 3) were used.

<u>Test 1</u> - Computes the difference between the following two percentages:

a) The average of the monthly system peaks during the reported peak period as a percentage of the annual peak, and

b) The average of the system peaks during the remainder of the test period as a percentage of the annual peak.

For calculated differences that fell between 18% and 19%, the FERC typically adopted a 12 CP methodology. For differences that fell between 26% and 31%, the FERC typically adopted a 4 CP methodology.

Test 2 - The average of the twelve monthly peaks in the reporting period as a percentage of the annual peak. When the resulting percentage fell between 81% and 88%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 78% and 81%, the FERC typically adopted a 4 CP methodology.

Test 3 - The lowest monthly peak as a percentage of the annual peak.

When the resulting percentage fell between 66% and 81%, the FERC typically adopted a 12 CP methodology. When the resulting percentage fell between 55% and 60%, the FERC typically adopted a 4 CP methodology.

Q. Did you apply these FERC tests to the KCP&L data?

A. Yes. As illustrated on Schedule 4, the following percentages using the demands recorded for the twelve-month period ending December 31, 2005 were calculated:

Test 1 - 28%

Test 2 - 76%

Test 3 - 57%

Q. Please discuss the significance of these results.

A. The result of the first test (28%) falls within the above-indicated 26%-31% range of results that led to FERC decisions adopting a 4 CP methodology. The result of the second test (76%) is well below the range suggesting a 12 CP methodology (81%-88%) and just slightly below the 78%-81% range of results in FERC decisions adopting a 4 CP methodology. The result of the third test (57%) falls within the 55%-60% range for which the FERC issued decisions adopting a 4 CP methodology. These tests support the usage of the 4 CP method.

Q. Which Staff witness used your jurisdictional demand allocation factors?

A. I provided these jurisdictional demand allocation factors to Staff witness Phil Williams.

ENERGY ALLOCATION FACTORS

Q. What energy allocation factors are you recommending be used in this case?

A. The factors are shown in Schedule 5 and repeated here.

Missouri Retail	**0.5668**
Kansas Retail	**0.4243**
Wholesale	**0.0089**

Q. What types of costs were allocated on the basis of energy?

A. Variable expenses, such as fuel and certain operational and maintenance (O&M) costs, are allocated to the jurisdictions based on energy consumption.

Q. How did you calculate the energy allocation factors?

A. The energy allocation factor for an individual jurisdiction is the ratio of the adjusted annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total adjusted kWh usage in all jurisdictions. The sum of the energy allocation factors across jurisdictions equals one.

Q. What adjustments were made to these kWhs?

A. The Staff made the following adjustments to be consistent with the net system hourly loads used in determining normalized fuel costs:

a. Normalization Adjustment

b. Annualization Adjustment

c. Customer Growth Adjustment

d. Wholesale Weather Adjustment

Q. Did you calculate these adjustments?

A. No. Staff witness Shawn E. Lange supplied adjustments a., b., and d. Please refer to Mr. Lange's testimony for a summary of these adjustments. Staff witness Kim Bolin provided the customer growth adjustment. Please see Ms. Bolin's testimony for a further explanation of this adjustment. These were the same adjustments used in calculating current revenues and the hourly loads input into the fuel and purchased power production cost run.

Q. Which Staff witness used your jurisdictional energy allocation factors?

A. I provided these jurisdictional energy allocation factors to Staff witness Phil Williams.

Q. Does this conclude your prepared Direct Testimony?

A. Yes, it does.

Schedule 1

Calculation of System Losses in MWh

NSI = Total Sales + Company Use + System Losses
NSI = Net Generation + Net Interchange + Inadvertent Flows
Total Sales + Company Use + System Losses = Net Generation + Net Interchange + Inadvertent Flows

Solving for System Losses:
System Losses = Net Generation + Net Interchange + Inadvertent Flows - Total Sales - Company Use

	Net Generation	Net Interchange (Off System Purchases - Off System Sales)	Inadvertent Flows	Total Sales to Ultimate Consumers	Company Use	Calculated System Losses	System Loss Factor = System Losses/NSI*
Source:	DR # 184	Ferc Form 1 and Reported 3190 Data	DR # 189	DR # 182	DR # 183		
	19,613,154.00	**-3,683,286.00**	**251.19**	**15,061,052.00**	**23,611.00**	**845,456.19**	**5.322%**

* NSI data source is DR # 30

KCP&L 2005		Jurisdictional Demand Allocation Factors
4CP Totals		
MO Retail	7100.9	0.5346
KS Retail	6073.9	0.4573
Wholesale	108.3	0.0082
LOAD	13283.1	

A Guide To FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers

Third Edition

Michael E. Small

Edison Electric Institute
WASHINGTON, DC

SCHEDULE 3-1

Chapter Five—Functionalization, Classification, and Allocation

In allocating costs to a particular class of customers, there are three major steps (if all cost of service issues have been resolved): (1) functionalization, (2) classification, and (3) allocation. FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation. *See, e.g., Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶61,222, p. 61,504 (1983); *Utah Power & Light Co.*, Opinion No. 113, 14 FERC ¶61,162, p. 61,298 (1981).[133]

A. Functionalization

Generally, plant or expense items are first functionalized into five major categories:

(1) Production;

(2) Transmission;

(3) Distribution;

(4) General and Intangible; and

(5) Common and Other.

See 18 C.F.R. §35.13(h)(4)(iii) (plant); 18 C.F.R. §35.13(h)(8)(i) (O&M expenses). Each plant or expense item will be segregated into the category with which it is most closely related.

While functionalization for most items is relatively straightforward, and not usually litigated, problems do arise with respect to the functionalization of administrative and general expenses (A&G)[134] and general plant expenses.[135] FERC stated that:

> The Commission normally requires that A&G and General Plant expenses be allocated on the basis of total company labor ratios. Under such allocation method, A&G and General Plant expense items are 'functionalized,' or segregated into...

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133 Where a company has significant non-jurisdictional business, the above cost incurrence principle is important in keeping FERC within its jurisdictional constraints. *See Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 641–42 (1945) ("the Commission must make a separation of the regulated and unregulated business...Otherwise the profits or losses...of the unregulated business would be assigned to the regulated business and the Commission would transgress the jurisdictional lines which Congress wrote into the Act").

134 A&G expenses include salaries of officers, executives, and office employees, employee benefits, insurance, etc.

135 General plant includes office furniture and equipment, transportation vehicles, lockers, tools, lab equipment, etc.

SCHEDULE 3-2

Co., 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648–49 (1980).[136]

In addition to FERC's adoption of Staff's predominance method, FERC also has adopted Staff's classification index of production O&M accounts. *Arizona Public Service Co.*, 4 FERC at 61,209–10; *Kansas City Power & Light*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648–49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by Staff, which has been approved by the Commission." In *Southern Company Services*, Opinion No. 377, 61 FERC ¶61,075, p. 61,311 (1992), *reh. denied*, 64 FERC ¶61,033 (1993), FERC, however, stated that the Staff index is not mandatory. FERC accepted a departure from the Staff's index, though it held that a party proposing a departure has the burden of justifying that departure.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak (CP) method. *Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) ("Maine Public has cited a legion of Commission decisions affirming the use of a coincident peak demand allocator.... And, it denies knowledge of '*any* decision, involving an electric utility since the FERC came into existence in 1977, where FERC did not follow a coincident peak method of allocating demand costs' "). In *Lockhart Power Co.*, 4 FERC ¶61,337, p. 61,807 (1978), FERC stated that its "general policy is to allocate demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092. Under a CP method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period. The basic assumption behind this method is that capacity costs are incurred to serve the peak needs of customers.

1. Coincident Peak Allocation

In most cases, FERC has accepted one of four CP methods—1 CP, 3 CP, 4 CP, and 12 CP, with the largest number of companies using a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12

136 If a company is able to justify a percentage split, such as 70–30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method likely will have the burden of justifying its proposed split.

SCHEDULE 3-3

(2) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(26% difference—4 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(18% difference—12 CP);

(4) *Illinois Power Co.*,
11 FERC at 65,248,
(19% difference—12 CP);

(5) *Commonwealth Edison Co.*,
15 FERC at 65,196
(16.4-24.9% differences—4 CP);

(6) *Southwestern Public Service Co.*,
18 FERC at 65,034
(average difference of 22.9%; high of 28.3%—3 CP).

FERC also has used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(56%—4 CP);

(2) *Idaho Power Co.*,
Opinion No. 13,
3 FERC ¶61,108 (1978)
(58%—3 CP);

(3) *Southwestern Electric Power Co.*,
Opinion No. 28,
4 FERC ¶61,330 (1978)
(55.8%—4 CP);

(4) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(73%—12 CP);

(14) *Delmarva Power & Light Co.*,
17 FERC at 65,201
(71.4%—12 CP).

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four year period, a peak in one of the 4 peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*,
11 FERC at 65,248–49
(81%—12 CP);

(2) *El Paso Electric Co.*
Opinion No. 109,
14 FERC ¶61,082 (1981)
(84%—12 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(84%—12 CP);

(4) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(87.8%—12 CP);

(5) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(81.2%—4 CP);

(6) *Commonwealth Edison Co.*,
15 FERC at 65,198
(79.4–79.5%—4 CP);

used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion No. 359-A, 54 FERC at 62,020 (accepted system peak demand and energy sales forecasts based on 1967-1981 data and 1981 coincidence factors). In other cases, FERC, however, has adopted CP projections based on the use of one year's data. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. In *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

FERC Tests to Determine Appropriate Allocation Methodology

FERC Test # 1					
	This test calculates the difference in the following two averages: Average of monthly system peaks during peak period (June - August) as percentage of annual peak and,	3320.8	0.945497	**28.05%**	Results suggest 4CP methodology*
	Average of system peaks during the remainder of the test period as a percentage of the annual peak	2335.6	0.664993		
FERC Test # 2					
	Average of the twelve monthly peaks in the reporting period as a percentage of the annual peak.	2663.983		**75.85%**	**Results suggest 4CP methodology****
FERC Test # 3					
	This test looks at the lowest monthly peak as a percentage of the annual peak:	0.570355		**57.04%**	Results suggest 4CP methodology***

* For the calculated differences that fell between 18% and 19%, te FERC typically adopted a 12 CP methodology. For differences that fell between 26% and 31%, the FERC typically adopted a 4 CP methodology.

**When the percentage falls between 81% and 88%, the FERC typically adopted a 12 CP mehtodology. When the resulting percentage fell between 78% and 81%, the FERC typically adopted a 4CP methodology.

***When the percentage falls between 66% and 81%, the FERC typically adopts a 12 CP mehtodology. When the percentage falls between 55% and 60%, the FERC typically adopts a 4CP methodology.

KANSAS CITY POWER & LIGHT
COMPONENTS OF ANNUAL NET SYSTEM INPUT
ER-2006-0314

	Energy (kwh) w/losses	Large Customer Annualizations	Normalization for Weather	Additional kWh from Cust Growth	Total KCP&L Normalized kWh	**Energy Allocation Factors**
Mo Retail	9,048,186,068	35,091,217	-106,330,915	28,648,206	9,005,594,576	0.5668
Non-Mo Retail	6,741,261,990	4,187,176	-108,604,842	105,733,693	6,742,578,016	0.4243
Wholesale	143,054,274	-	-1,534,262	-	141,520,012	0.0089
Company Use	24,871,625	-	-	-	24,871,625	
NSI	15,957,373,958	39,278,393	-216,470,019	134,381,898	15,914,564,230	1

Evergy Missouri Metro
Case Name: 2022 Evergy MO Metro Rate Case
Case Number: ER-2022-0129

Requestor Opitz Timothy -
Response Provided April 25, 2022

Question:4-1

Will a storm reserve as proposed by Evergy lessen the time it takes to restore service for customers? If the answer is yes, please explain in detail the rationale for the response.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

The proposed storm reserve does not lessen the time it takes to restore service for customers.

Information provided by: Lili Hsu, Senior Regulatory Analyst

Attachment(s): N/A

Missouri Verification:
I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently

discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs