Exhibit No.:	
Issue(s):	*Storm Reserve, Incentive Compensation, Jurisdictional Allocations*
Witness:	*Keith Majors*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal / True-Up Direct Testimony*
Case No.:	*ER-2026-0143*
Date Testimony Prepared:	*September 10, 2026*

MISSOURI PUBLIC SERVICE COMMISSION

FINANCIAL AND BUSINESS ANALYSIS DIVISION

AUDITING DEPARTMENT

SURREBUTTAL / TRUE-UP DIRECT TESTIMONY

OF

KEITH MAJORS

EVERGY METRO, INC. d/b/a Evergy MISSOURI METRO

CASE NO. ER-2026-0143

Jefferson City, Missouri
September 2026

** Denotes Confidential Information **

TABLE OF CONTENTS OF

SURREBUTTAL / TRUE-UP DIRECT TESTIMONY OF

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CASE NO. ER-2026-0143

SURREBUTTAL / TRUE-UP DIRECT TESTIMONY

OF

KEITH MAJORS

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

Q. Please state your name and business address.

A. Keith Majors, Fletcher Daniels Office Building, 615 East 13th Street, Room 201, Kansas City, Missouri, 64106.

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

A. I am a Utility Regulatory Audit Unit Supervisor employed by the Staff ("Staff") of the Missouri Public Service Commission ("Commission").

Q. Are you the same Keith Majors who previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on June 30, 2026, and rebuttal testimony on August 11.

Q. What is the purpose of your surrebuttal / true-up direct testimony?

A. I will respond to the rebuttal testimony of Evergy Metro Missouri ("EMM") witnesses Ronald A. Klote concerning stock based compensation, EMM's requested Storm Reserve, cybersecurity tracker, and pension expense, and John Wolfram concerning jurisdictional allocations. I also identify my recommended true-up adjustments in this case.

SURREBUTTAL TESTIMONY

STORM RESERVE

Q. On page 29 of his rebuttal testimony, Mr. Klote notes that storm restoration costs are a legitimate and necessary cost of providing safe and reliable electric service, and that they should be recoverable through rates. Do you agree and do you have a response?

A. These costs are absolutely legitimate and they should be recovered through the cost of service. Staff opposes EMM's request for a storm reserve because these costs are an example of normal utility costs that should be normalized in the ratemaking process.

Q. Did EMM recommend an adjustment for storm restoration expenses in its rate case filing?

A. No, EMM did not recommend a specific normalization adjustment for storm restoration expenses, separate from the establishment of a reserve. EMM did include a three-year average of distribution maintenance expenses which includes most of the storm expenses that are at issue with the storm reserve. Staff included a three-year average of distribution maintenance expenses, albeit using a different time period. Staff has included a three-year average of distribution maintenance expenses for the period ending June 2026 which is the true-up cutoff in this case and the most recent data available.

Q. What are the differences between a pre-funded reserve for expenses and a tracking mechanism?

A. A pre-funded reserve is an amount for expenses included in the cost of service beyond the amount of the normalized level of that expense. The reserve would be a “savings account” that would fund storm restoration costs that exceed $250,000. EMM would retain the amounts between cases with the opportunity to adjust the amount of annual reserve contributions during a rate case. To the extent storm expenses do not exceed $250,000, EMM would have access to the funds.

A tracker would record the difference between the base level of an expense included in rates for a year, and the actual costs incurred for that expense, into a regulatory asset for future recovery or a regulatory liability for future return to customers. Depending on the cost being tracked, the unamortized portion of the tracker is sometimes included as an addition or as a reduction to rate base. Property taxes are tracked in this manner.

The differences between these two mechanisms are cashflow and risk. The reserve would increase the cashflow between rate cases but provide less risk mitigation as storm expenses that exceed the amount recorded to the reserve would not be subject to tracking. As Mr. Klote noted on page 30 of his rebuttal testimony, if the storm were substantial enough, EMM could seek recovery of storm costs through an Accounting Authority Order (“AAO”).

A tracker would reduce the risk of recovery of storm expenses but not provide immediate cash flow for these expenses.

Q. Has the Commission denied establishment of a storm reserve in a prior rate case?

A. Yes. As I noted in my rebuttal testimony, the Commission denied a storm reserve proposal in favor of specific storm expense recovery through deferral and amortization. I attached the relevant portions of the Commission's Report and Order in the Wolf Creek rate case, Case No. EO-85-185 to my rebuttal testimony filed in this case.

Q. Has the Commission denied a tracker for storm restoration costs for an electric utility?

A. Yes. In Case No. ER-2010-0036, the Commission denied AmerenUE's[1] request for a storm restoration tracker. The Commission discussed storm expenses generally, and addressed AmerenUE's request in its Report and Order:

> 1. AmerenUE must spend money each year to restore electric service after its electric system suffers damage as the result of storms. Each year some of that damage results from normal, routine storms. But occasionally, the electric system is struck by a truly extraordinary storm that can greatly increase restoration costs.
>
> 2. The Commission has generally allowed an electric utility to recover the Operations and Maintenance (O&M), excluding internal labor, costs to restore service after normal storms by including an amount in the cost of service based on some multiyear average level. For the costs to restore service after an extraordinary storm, the Commission has usually allowed the utility to accumulate and defer those costs through an accounting authority order, an AAO. The accumulated and deferred costs are then considered in the utility's next rate case. Generally, the Commission allows the utility to recover those costs amortized over a five-year period.
>
> 5. ...Under the approach the Commission has used in past cases, the company may under recover in years when costs are high, but may over recover in years when costs are low. If the company incurs truly extraordinary storm restoration costs in a particular year, it is able to recover those costs through the

[1] Now doing business as Ameren Missouri.

> accounting authority mechanism. In this case, AmerenUE is recovering amortized storm restoration costs from five different storm events.
>
> 6. No party disputes that AmerenUE has provided good storm restoration service in recent years, and no one has alleged that any of its storm restoration expenses have been imprudent.
>
> 7. The Commission is unwilling to implement another tracker. As the Commission has previously indicated, trackers should be used sparingly because they tend to limit a utility's incentive to prudently manage its costs. If all such costs can simply be passed on to ratepayers, there is a natural incentive for the company to simply incur the cost. If the company must consider whether it will be able to recover a cost, it is more likely to think before it spends and maximize any possible cost savings.
>
> 8. The storm cost recovery method the Commission has used in the past has worked reasonably well. The company will ultimately recover its extraordinary costs resulting from unpredictable extraordinary storms through the accounting authority order mechanism, but the company still has a strong incentive to minimize its costs...[2]

Q. What are the important points noted by the Commission concerning storm costs?

A. Including non-extraordinary storm costs in the cost of service as a normalized expense is the preferred method. EMM may recover more or less than the amount included in rates and has an incentive to minimize its costs.

Although EMM's requested storm reserve is not wholly comparable to the 2010 AmerenUE request, the Commission did make it clear that non-extraordinary storm costs were a normal utility cost and should not receive special treatment.

[2] Report and Order, Case No. ER-2010-0036, pages 65-68, multiple footnotes omitted.

EQUITY COMPENSATION

Q. On page 21 of his rebuttal testimony, Mr. Klote states, "Staff does not identify these costs as excessive, unreasonable, imprudent, or outside industry norms. Rather, the adjustment is based solely on the fact that the compensation is delivered through equity-based compensation programs." Do you agree with Mr. Klote?

A. Yes. Staff's adjustment is based upon Commission orders concerning the recovery of stock-based incentive compensation through the cost of service.

Q. Has the Commission had the opportunity to provide guidance on equity-based incentive compensation?

A. Yes. The Commission's Report and Order in Kansas City Power & Light Company's ("KCPL") rate case in File No. ER-2007-0291 is consistent with the Commission's historic treatment of equity-based compensation. In the Order, the Commission stated:

> KCPL has the right to tie compensation to [earnings per share]. However, because maximizing [earnings per share] could compromise service to ratepayers, such as by reducing maintenance, the ratepayers should not have to bear that expense. What is more, because KCPL is owned by Great Plains Energy, Inc., and because GPE has an unregulated asset, Strategic Energy L.L.C., KCPL could achieve a high [earnings per share] by ignoring its Missouri ratepayers in favor of devoting its resources to Strategic Energy. Even KCPL admits it is hard to prove a relationship between earnings per share and customer benefits. Nevertheless, if the method KCPL chooses to compensate employees shows no tangible benefit to ratepayers, then those costs should be borne by shareholders, and not included in the cost of service.[3]

[3] Report and Order, Case No. ER-2007-0291, dated Dec. 6, 2007, pg. 49-50 (internal footnotes omitted). See also Report and Order, Case No. ER-2006-0314, dated Dec. 21, 2006, pg. 58.

Q. Has the Commission issued a decision regarding stock compensation more recently than the KCPL decision above?

A. Yes. In Case Nos. GR-2017-0215 and GR-2017-0216, the Commission explained:

> The Commission has traditionally not allowed earnings based or equity based compensation to be recovered in rates because such incentives are primarily for the benefit of shareholders and not for the benefit of the ratepayers. As the Commission has said in the past, incentivizing employees to improve the company's bottom line aligns the interests with the shareholders and not with the ratepayers. Aligning interest in this way can negatively affect ratepayers.[4]

Q. Are the stock awards referenced in Mr. Klote's testimony any different than those already considered in these two prior rate cases?

A. No. Staff recommends the Commission re-affirm its guidance concerning incentive compensation and not include these expenses in the cost of service.

Q. What are the awarding criteria for EMM's stock compensation?

A. For the time-based stock units, shares vest after three years. For the performance-based stock units, there are three criteria for the awards:

- Evergy's[5] total shareholder return (''TSR'') relative to the companies included in the EEI index of electric utility companies (the ''EEI Index'') over the three-year performance period (50% of performance-based weighting);
- Evergy's 3-year cumulative adjusted EPS measured relative to the Company's long-term financial plan (42.9% of performance-based weighting); and

[4] Amended Report and Order, Case Nos. GR-2017-0215 & GR-2017-0216, dated Mar. 7, 2018, page 122 (emphasis added), aff'd on other grounds in Spire Missouri, Inc. v. Public Service Com'n, 2019 WL 1246323, Mar. 15, 2019.
[5] Evergy, Inc., total company, including all subsidiaries.

- An environmental measure based on adding renewable energy generation (7.1% of performance-based weighting).[6]

These metrics apply for stock grants during January 1, 2025 – December 31, 2027.

** [redacted]

- [redacted]
- [redacted]

[redacted] **

As the Commission ruled in both the 2007 EMM rate case and the 2017 Spire Missouri rate case, as well as numerous other rate cases, earnings-based incentive compensation should not be included in the cost of service.

Q. Does the stock compensation for EMM involve a cash outlay for EMM?

A. No, for the vast majority of transactions. I have attached the response to Staff Data Request 521 as Schedule KM-s1. This response notes that EMM issues shares directly to the recipient with no intermediary cash outlay. EMM's stock awards are essentially a dilution of equity. In a normal issuance of common stock directly from EMM, a purchaser would pay a price, however determined, in cash to EMM which would be recorded as paid in capital. EMM would receive the cash as a debit balance and record

[6] Evergy, Inc. 2026 Proxy Statement, page 37.
[7] Response to Staff Data Request 520.

the amount received as paid in capital credit balance. In this case, there is no cash outlay related to the stock award, and therefore no actual cash expense incurred by EMM.

A minor cash outlay would be incurred by EMM when it pays recipients for fractional shares as fractional shares do not exist.

Q. Are utility expenses that do not relate to an immediate cash outlay or transaction, but are recovered in the cost of service, relatively rare?

A. Yes. Two examples are bad debt expense and depreciation, both of which were related to a cash transaction at some point. Bad debt expense is an amount of revenue that was billed but unable to be collected from EMM's customers. EMM should have received the cash from billings but did not and after several months records the revenue as bad debt. A normalized amount of bad debt expense is included in the cost of service.

Depreciation expense is the ratable recovery from customers of the initial cash outlay for all items of plant in service. Cash is received from customers in the form of depreciation expense over the service life of the underlying assets.

On the contrary, EMM's stock compensation is not a cash outlay but rather a dilution of equity and should not be reflected in the cost of service as an expense.

PENSION EXPENSE

Q. On page 41 of his rebuttal testimony, Mr. Klote notes that Staff did not include the Prepaid Pension Asset in its direct filing. Has Staff included an appropriate amount in its true-up filing?

A. Yes. Staff recommends inclusion of the Prepaid Pension Asset as of June 30, 2026.

JURISDICTIONAL ALLOCATIONS

Q. On page 5 of his rebuttal testimony, Mr. Wolfram states "the results matter more than the method" in determination of the jurisdictional demand allocator. Do you agree?

A. No. Mr. Wolfram's philosophy is tantamount to "results based auditing," which is to suggest beginning with the conclusion first and finding evidence to support conclusions and ignoring controverting evidence with a preconceived bias. That is not Staff's approach. Staff's method uses objective evidence and reasoning to support the conclusion that a 4 Coincident Peak ("4CP") demand allocator has and continues to be the most appropriate for establishing EMM rates.

Using Wolfram's methodology, Staff should presumably ignore evidence, for example, that a three-year average for overtime should be used in Missouri because the Kansas Corporation Commission ("KCC") ordered such, when use of the last known overtime data is the most reasoned methodology given the facts and evidence in this particular proceeding. That would not be sound ratemaking.

Q. Based on the testimony of Mr. Wolfram, what is the ultimate result desired by EMM?

A. EMM, through using the flawed Wolfram allocation methodology seeks to mitigate allocation differences that it has perpetuated and in part has responsibility for creating.

EMM has perpetuated the difference of jurisdictional allocation factors between Missouri and Kansas since 2004. EMM has now new proposals to fix its problems.

Q. How has EMM perpetuated this problem?

A. EMM agreed to the use of the 12CP methodology as a condition of the Stipulation and Agreement in the Kansas Regulatory Plan. This agreement bound EMM to the 12CP methodology for the 2006, 2007, 2009, and 2010 Kansas rate cases. In the 2012 Kansas rate case, EMM proposed the 4CP method through its witness, Larry W. Loos, an engineer employed by the global engineering firm Black & Veatch. I attached his 2012 Kansas rate case direct testimony to my rebuttal testimony in this case. Meanwhile, EMM unsuccessfully sought to use the 12CP methodology in Missouri.

Q. On page 5 of his rebuttal testimony, Mr. Wolfram notes the relatively small difference between the various allocation methodologies. Why is this such an important issue for the Commission to determine?

A. Although there is only a fractional difference in the allocator, the difference is amplified when applied to billions of dollars of rate base investment. In the 2006 Rate Case, the Commission found the 4CP method was superior to EMM's 12CP method when the difference was 47 basis points. Mr. Wolfram calculates a current 45 basis point difference on page 5 of his rebuttal testimony between the 4CP and 4CP and12CP average, and an 89 basis point difference between the 4CP and 12CP methods.

Q. What is a basis point of difference, and how much does it affect the revenue requirement?

A. A basis point is 1/1000th as a decimal, or 1/100th of a percent. For example, using EMM's revenue requirement model, increasing the demand factor from 51.92% to 51.93%, or one basis point, increases the revenue requirement by approximately $96,000. Using EMM's model, the revenue requirement difference using 51.47% resulting from the 4CP method versus the 51.92% resulting from the average of the 4CP and 12CP method, is approximately $4.3 million.

Q. On page 2 of his rebuttal testimony, Mr. Wolfram recounts that 40 years ago, Missouri was willing to compromise on this issue but Kansas was not. Is this true?

A. Yes. The 4CP method was used in EMM's 1983 rate case. In that case, Case No. ER-83-49, the Commission's *Report and Order* stated at page 50 that "DOE [Department of Energy], Staff and the Company have agreed to use a four coincidental peak method to develop the Missouri jurisdictional demand allocation factor."

In the following rate case, EMM[8] proposed in the 1985 Wolf Creek rate case a 4CP method for production and transmission jurisdictional allocators. Staff proposed a 1CP method for these assets in that case. The Commission adopted EMM's use of the 4CP method of allocations. The Commission's *Report and Order* in Case Nos. ER-85-128 and EO-85-185 stated the following:

> Company asserts that 4CP is the appropriate allocation method since it represents a compromise position between what it views as two extremes: the 1CP approach taken by the Missouri Staff and the 12 CP approach taken by the Kansas Corporation Commission Staff. In addition, Company argues that 4CP better reflects the duration of the Company's summer peak load

[8] At that time, and until 2018, EMM did business as Kansas City Power & Light ("KCPL").

> resulting in cost allocation stability. Finally, KCPL asserts that the 4CP method allocates non-fuel production costs without the need to classify those costs as demand or energy related.....
>
> In the instant case, the Commission has only two proposals before it and both are peak responsibility methods. The Commission cannot adopt Staff's 1CP method in this case. The Commission stated in this Company's rate design investigation:
>
> > The coincidental peak method is the least equitable of the peak responsibility methods proposed in that it places total dependence on the single hour of system peak demand. Re: Kansas City Power & Light Company, 25 Mo. P.S.C. (N.S.) 605, 614 (1983).
>
> **The Commission determines that the 4CP method as proposed by the Company should be used for purposes of this case since the utilization of multiple peaks does recognize some plant usage occurring at times other than the single system peak.**
>
> Based on the foregoing the Commission determines that the production and transmission allocators to be used for purposes of this case shall be 65.78[%] and 59.89[%] respectively.
> [emphasis added]

I have attached the relevant portion of the Wolf Creek order in Case No. EO-85-185 as Schedule KM-s2.

Q. The Missouri Commission compromised in 1985. When the Kansas Commission had the opportunity to compromise, did it move to a middle ground?

A. No. I have attached sections of two documents, the entirety of which can be provided but are rather lengthy, as Schedule KM-s3. The first is an excerpt from the

KCC Staff brief from the Kansas Wolf Creek rate case[9] and the second is an excerpt from the KCC order from that case.

Q. Please explain the relevance of these documents.

A. The KCC Staff brief discusses EMM's recommendation of the 4CP method in contrast to both KCC staff's and the KCC historic use of the 12CP methodology. Mr. Sullivan, an EMM witness at the time, recommended to the KCC to use the 4CP method as a compromise between the 1CP allocator proposed by the MOPSC Staff at the time, and the 12CP recommendation of the KCC staff. As the brief noted, "[t]he 4CP allocator, in his [EMM witness Mr. Sullivan] opinion, better reflects the primary cost causative factor in KCPL's investment in production."

The KCC Order notes the suggestion of compromise by Mr. Sullivan, as well as the support of EMM witnesses Knodel and LaCapra of the 4CP method. As noted by the KCC, it continued to support the 12CP method, while the Missouri Commission not long after did compromise to the 4CP method.

In a direct response to Mr. Wolfram: yes, Missouri has compromised on this matter, while Kansas has not met Missouri in the middle, that is, the 4CP methodology.

CYBERSECURITY COSTS

Q. On page 33 of his rebuttal testimony, Mr. Klote claims that cybersecurity expenses are significant and can vary materially from year to year. Has this been the case with the recent costs EMM has incurred?

[9] Consolidated Docket No. 120,924-U, Docket No. 142,099-U, and 84-KCPE-198-R.

A. No. The table below lists the annual cybersecurity expenses since the last rate case, Case No. ER-2022-0129:

** [redacted] **

Q. Did Staff or EMM adjust cybersecurity costs from the test year amount?

A. No.

<u>TRUE-UP DIRECT</u>

Q. What is Staff's recommended revenue requirement for EMM?

A. Staff's recommended true-up revenue requirement is $68,815,926 at Staff's mid-point rate of return ("ROR") of 7.25%The recommended revenue requirements range from $62,381,314 at an ROR of 7.12% and $75,201,417 at an ROR of 7.38%. Staff's recommended return on equity ("ROE") at the mid-point is 9.73%, with a range of 9.48%-9.98%. This recommended true-up revenue requirement is before the inclusion of the Large Load Power Service ("LLPS") revenues as calculated by Staff witness Sarah L.K. Lange.

Q. What revenue requirement items do you sponsor for Staff's true-up filing?

A. I sponsor the following adjustments to Staff's revenue requirement.

- Pension and Other Post Employment Benefit ("OPEB")_expense and tracker
- Supplemental Executive Retirement Program ("SERP")
- Jurisdictional allocations

Q. Do any of you adjustments include changes in methodology?

A. No.

Q. Does this conclude your surrebuttal / true-up direct testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF Jackson)

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Rebuttal Testimony of Keith Majors*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 10 day of August 2026.

T'ZIAH L RILEY
Notary Public, Notary Seal
State of Missouri
Jackson County
Commission # 25680847
My Commission Expires 04-28-2029

Notary Public

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Majors Keith -
Response Provided September 03, 2026

Question:0521
Reference the rebuttal testimony of Ron Klote in this case.
1) How are the units of common stock related to time-vested, performance shares, restricted stock units, and any other equity awards acquired by Evergy, or any of its affiliates and/or subsidiaries? For example, when transferring the compensation to the recipient, does Evergy issue new stock, issue from existing treasury shares that have been repurchased, or some other source? If the shares were acquired through an affiliate or subsidiary, how did that entity acquire the shares?
2) When the equity awards in Item 1 are conveyed to the recipient, other than income and FICA tax withholdings, is there any other cash outlay by the entity granting the stock? Requested by: Keith Majors (keith.majors@psc.mo.gov)

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:

1) Evergy issues shares from the Amended and restated 2022 long term incentive plan.
2) Shares are withheld to cover all applicable taxes (not just FICA) for both time-based and performance based RSUs. Regarding time-based RSUs, participants receive cash in lieu of fractional shares. Any difference between the remaining amount needed for taxes and the cash for fractional shares is paid to the participant. For performance based RSUs, dividend equivalents go toward the payment of taxes prior to shares being withheld. Any difference between the amount needed for taxes and the value of the shares withheld is paid to the participant.

Information provided by:

Janece L. Worner, Lead Compensation Analyst

Attachment(s):

<u>Missouri Verification:</u>
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

3. That the parties agree to file, under affidavit, answers to any questions the Commission may ask about this case and that the questions and answers mentioned above shall be received into the record as evidence.

4. That the parties shall be permitted to submit initial briefs and reply briefs in this docket, pursuant to a schedule to be established by the Commission.

EDITOR'S NOTE: Signature lines have been omitted.

In the matter of Kansas City Power & Light Company of Kansas City, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company, and the determination of in-service criteria for Kansas City Power & Light Company's Wolf Creek Generating Station and Wolf Creek rate base and related issues.*

In the matter of Kansas City Power & Light Company, a Missouri corporation, for determination of certain rates of depreciation.

Case Nos. EO-85-185 and EO-85-224
Decided April 23, 1986

Electric §§1, 14, 20, 28, 31, 31.1. Public Utilities §§1, 39. Rates §§108, 109. The four coincidental peak method of determining system production and transmission

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*Refer to Volume 27, page 357, for in-service criteria for the Wolf Creek nuclear plant.

The Commission, in an order issued June 2, 1986, denied a rehearing in this case.

This order contains changes approved by the Commission in the June 2 order.

The June 2 order also took note of a letter filed by intervenor Department of Energy (DOE) which said DOE's adjustment study was reduced from $7,790,000 to $4,207,000. As a result of that reduction, the $6.8 million figure appearing at line 13, page 420 of this volume is inaccurate as it assumes the $7.7 million figure contained in the long-range operating study. The June 2 order pointed out that this inaccuracy does not affect findings with respect to the appropriateness of offsetting the annual deferrals by the operating savings set forth in the Company's long-range operating study.

The June 2 order also clarified this order to the extent that phase-in tariffs to be filed in accordance with the phase-in plan shall bear an effective date of May 5 in each subsequent year of the phase-in. Such tariffs will automatically take effect in succeeding years unless suspended by the Commission for good cause shown.

The June 2 order also pointed out that any determination concerning excess capacity in the future and the appropriate ratemaking treatment thereof will be based on the facts and circumstances existing at the time of the inquiry.

This order has been appealed. See Court Cases page.

Case No. ER-2026-0143
Schedule KM-s1
Page 1 of 4

that order were submitted, as noted on Appendix C. Upon obtaining the responses to those requests, Staff, KCPL, Public Counsel and DOE filed their response to the Order Directing Revenue Requirement Calculations on March 28, 1986, and April 2, 1986. On April 1, 1986, the Commission requested that additional phase-in schedules be submitted. Those schedules were filed April 3, 1986.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact.

PHASE I - IN-SERVICE CRITERIA, JURISDICTIONAL ALLOCATIONS AND RATE OF RETURN

I. *In-Service Status of Wolf Creek Generating Unit*

In the Commission's Report And Order effective May 29, 1985, the Commission adopted the Joint Recommendation On In-Service Criteria of Staff and Company. On September 5, 1985, Company submitted its Notice Of Satisfaction Of In-Service Criteria (Exhibit 180), which asserted that Wolf Creek Generating Station had satisfied the Commission's in-service criteria as of 1:15 o'clock a.m., September 3, 1985. On October 11, 1985, Staff filed its Evaluation Of In-Service Status Of Wolf Creek Generating Station, Unit 1. Staff concluded in its filing that the Wolf Creek Generating Station had complied with the Commission's in-service criteria.

Based upon the foregoing, the Commission finds the Wolf Creek Generating Station has met the Commission's in-service criteria and was fully operational, in accordance with Section 393.135, R.S.Mo. 1978, at 1:16 a.m. on September 3, 1985.

II. *Jurisdictional Allocations*

A. *Stipulation and Agreement*

Staff and KCPL presented a *Stipulation and Agreement Regarding Jurisdictional Allocations.* The Stipulation and Agreement reflects that Staff and KCPL have resolved all issues regarding Jurisdictional Allocations except for the method to be used for determining production and transmission system demand allocators.

The Commission has reviewed the *Stipulation and Agreement Regarding Jurisdictional Allocations* and determines that it is a reasonable and just resolution of the issues addressed therein and should be approved. The Stipulation and Agreement which was received into evidence as Exhibit 18, is made a part of this order and attached hereto as Appendix A.

B. *Production and Transmission System Demand Allocators*

Staff proposes that the one coincidental peak (1CP) methodology be used for purposes of determining system production and transmission demand allocators, while the Company proposes the four coincidental peak (4CP) method. The 1CP method produces production and transmission allocators of 65.10 and 59.81 respectively. The production and transmission allocators resulting from the 4CP method are 65.78 and 59.89 respectively.

In the event the Commission determines the 1CP method to be appropriate, the Company recommends that non-fuel production expenses be classified as demand or energy related and that only demand related non-fuel production expenses be allocated by means of the 1CP allocator.

Staff's 1CP method is based on the premise that sufficient plant capacity must be available to meet system peak and, therefore, the system peak is the primary determinant of plant costs.

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

KCPL argues that Staff is inconsistent in its allocation methods since it utilized the 12CP method for the last Union Electric rate case. Re: *Union Electric Company*, 27 Mo. P.S.C. (NS) 183 (1985). Company also argues that Staff uses inconsistent allocation methods for jurisdictional allocations and class allocations.

Staff's 1CP method is based on the peak responsibility theory of cost causation. Staff's time of use (TOU) allocation method, which Staff has advocated in this and other cost of service and rate design proceedings is based on a rejection of the peak responsibility theory. Staff's TOU method is based on the theory that generation and bulk transmission plant is built to serve loads every hour of the year and not just the peak hour.

The Commission has rejected the theory that new capacity is added solely to meet system peak and peak responsibility allocation methods based on that theory. In rejecting the peak responsibility theory of cost causation, the Commission has accepted Staff's TOU method and its underlying theory of cost causation for the allocation of generation and bulk transmission plant among classes. Re: *Arkansas Power & Light Company,* 25 Mo. P.S.C. (N.S.) 101 (1982); Re: *Kansas City Power & Light Company,* 25 Mo. P.S.C. (N.S.) 605 (1983) and Re: *Union Electric Company,* 27 Mo. P.S.C. (N.S.) 183 (1985).

In the instant case, the Commission has only two proposals before it and both are peak responsibility methods. The Commission cannot adopt Staff's 1CP method in this case. The Commission stated in this Company's rate design investigation:

> The coincidental peak method is the least equitable of the peak responsibility methods proposed in that it places total dependence on the single hour of system peak demand. *Re: Kansas City Power & Light Company*, 25 Mo. P.S.C. (N.S.) 605, 614 (1983).

The Commission determines that the 4CP method as proposed by the Company should be used for purposes of this case since the utilization of multiple peaks does recognize some plant usage occurring at times other than the single system peak.

Based on the foregoing the Commission determines that the production and transmission allocators to be used for purposes of this case shall be 65.78 and 59.89 respectively.

III. *Rate of Return*

The Company, Staff and Department of Energy (DOE) have stipulated to the following capital structure, embedded cost of debt and preferred and preference stock at December 31, 1984:

Capital Component	Capital Ratios	Embedded Cost	Weighted Cost
Long Term Debt	51.75%	9.71%	5.02%
Preferred/Preference	10.87%	10.26%	1.12%
Common Equity	37.38%		
	100.00%		

The Commission determines that the agreed-upon capital structure, embedded cost of debt and preferred and preference stock are reasonable and should be adopted. Therefore, the only rate of return issue which remains is the determination of an appropriate return on equity for KCPL.

KCPL is proposing what could be characterized as both a pre-Wolf Creek in-service (preoperational) and a post-Wolf Creek in-service (operational) return on equity. KCPL's proposed preoperational return on equity is 19 percent, which is then adjusted for costs associated with the issuance of common stock and the demands of market pressure. That adjustment results in a cost of equity to the Company of 20 percent.

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BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company Requesting Proposed Changes in its Charges for Electric Service	) DOCKET NO. 142,099-U 84-KCPE-198-R

STAFF BRIEF

Brian J. Moline, General Counsel

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Attorneys for Commission Staff

Case No. ER-2026-0143
Schedule KM-s3
Page 1 of 12

State Corporation Commission
Rec'd AUG 30 1985 A.P.M.
Judith McConnell, Secretary

VI. JURISDICTIONAL SEPARATIONS

Staff: Witness: Marker, (TR. Vol. A-4, p. 872-894)

KCPL: Witness: Sullivan, (TR. Vol. XVI, p. 4418-4456; TR. Vol. A-3, p. 437-541; TR. Vol. A-5, p. 1234-1250)

Exhibit: G-KCPL-52

Witness: Knodel, (TR. Vol. XVI, p. 4418-4469; TR. Vol. A-3, p. 541-596)

Exhibit: G-KCPL-51

Witness: LaCapra, (TR. Vol. A-4, p. 773-823)

Exhibit: A-KCPL-14

Issue: Whether KCPL's production and transmission plant should be allocated among FERC, Missouri, and Kansas jurisdictions by using a twelve coincident peak (12 C.P.) method to recognize the effect of substantial non-summer electrical usage on capacity costs.

Discussion:

Staff witness, Don Marker, testified that, having reviewed KCPL's jurisdictional separations, he disagreed with KCPL's proposed method of allocating its production and transmission related costs among the different jurisdictions. KCPL proposes using the average of four summer (June, July, August, September) coincident peaks (4 C.P.) to make jurisdictional power supply allocations. Mr. Marker opposes this method of allocation because it does not recognize the capacity requirements associated with the eight non-summer months. Specifically, it ignores the fact that during the eight non-summer months, peak usage by KCPL's customers company-wide averages about 64 percent of the summer peaks, and in no month is it less than 62 percent. (Marker, TR. Vol. A-4, p. 877, 885). Mr. Marker recommends that KCPL's production and transmission plant be allocated among the jurisdictions by means of a twelve coincident peak (12 C.P.) allocator because such an allocator recognizes the capacity requirements in all twelve months of a year. Mr. Marker explains that a utility determines the type and cost of its capacity by means of the total loads during all twelve months of the year, and not only the system peak loads. He explains that system peak load may determine the total amount of generation capacity, but not the type and cost of that capacity. In other words, a utility may invest in base load, intermediate and peak load plants. Peak load plants are characterized by low fixed costs and high variable costs, whereas base load plants are characterized by high fixed costs and low variable costs. These cost differences are considered when a utility plans its generation mix of plants. Specifically, a utility would invest in a base load plant with high fixed costs in order to economically generate energy on an annual basis. (Marker, TR. Vol. A-4, p. 878).

Mr. Marker studied KCPL's generation capacity, and he testified that 98.6 percent of KCPL's total production rate base is base load capacity on a dollar investment basis; and that on a KW basis, 85.4 percent of KCPL's production capacity is base load. Further Mr. Marker testified that KCPL's net investment in base load plant is $697 per KW while its net investment in other plant is only $57 per KW. Mr. Marker logically concludes that a utility does not invest in base load facilities to serve summer peak alone, thus base load costs should not be allocated among jurisdictions solely on summer peaks. (Marker, TR. Vol. A-4, p. 879-880).

Currently KCPL's jurisdictional rates are based on a 12 C.P. allocation factor, as ordered by this Commission in the last KCPL rate order dated March 29, 1983, (Docket No. 133,002-U). In that order the Commission found that the twelve coincident peak method is superior to the company's four coincident peak method because it recognizes the company's investment in base load facilities which are utilized year round and not solely during the summer peak months. KCPL's current rate case coincides with the expected commercial operation of the Wolf Creek Generating Station (WCGS), a base load unit. In Mr. Marker's expert opinion, this fact serves to add support to his position that a 12 C.P. allocation factor should be used rather than a 4 C.P. allocation factor in separating production and transmission facilities among the various jurisdictions that KCPL serves. Mr. Marker calculated that if the total costs of Wolf Creek, including fixed and variable costs, were attributed solely to the four summer months, KCPL would face a cost per KWH produced from Wolf Creek, not including any transmission, distribution or overhead costs, of approximately 26.6 cents per KWH. This compares with a 9.7 cents per KWH of fully embedded costs of Wolf Creek when operated on a twelve month basis. Mr. Marker points out the absurdity of assigning all Wolf Creek capacity costs to the summer months because it is not logical to invest in base load plant at a cost of 26.6 cents per KWH. (Marker, TR. Vol. A-4, p. 882-883).

Mr. Marker summarized his recommendation for using the 12 C.P. allocation factor for production and transmission facilities by stating that his costing analysis results in a fair and equitable apportionment of electric costs among the customers of KCPL. His analysis shows that not all capacity costs are summer peak related. KCPL's proposed allocation methodology would assess Kansas retail customers more than $9.3 million per year in unreasonable revenue requirements. (Marker, TR. Vol. A-4, p. 883).

On cross-examination by Chairman Lennen, Mr. Marker indicated that if KCPL's production and transmission facilities were allocated among jurisdictions by two production allocators, a 12 C.P. allocator for base load plant and a 4 C.P. or other similar method for intermediate and peaking plant, there would be only a nominal difference in the result because of the predominance of base load generating capacity on the KCPL system.

KCPL's witness LaCapra recommended that production capacity costs be assigned to various classifications of service on an average of the four summer maximum peak loads. Staff notes that Mr. LaCapra's testimony only discusses production capacity costs. No KCPL witness discussed the allocation of transmission plant. Mr. LaCapra alleges that the summer peak is the central planning concern of the company in assessing the need for new capacity. Staff counsel asked whether he included WCGS in that need for new capacity, and Mr. LaCapra indicated that the statement was generic so to that extent it would include any unit. (LaCapra, TR. Vol. A-4, p. 803). He testified that the capacity requirement during the four summer months was central in the planning for the construction of WCGS. He distinguishes his statements from Mr. Doyle's statement that Wolf Creek is not a peak load plant by stating that, in the planning process, he believes, that new generation is only considered, initially, because there is a need to serve peak. He does agree, however, that Wolf Creek will unquestionably serve base load. Ironically, although Mr. LaCapra is proposing an allocation methodology for separating KCPL's plant among the jurisdictions, he did not have any specific knowledge with regard to KCPL's production resources being base load, peaking or intermediate. Nor was he specifically familiar with all of the production units that KCPL has. Further, although Mr. LaCapra is making recommendations about how to allocate costs, he could not specifically state what KCPL's dollar investment is in its total production related rate base. (LaCapra, TR. Vol. A-4, p. 806-807).

In answer to a question by Chairman Lennen, Mr. LaCapra indicated that KCPL would send an appropriate pricing signal if a base load unit such as Wolf Creek is allocated as if it were a summer peaking unit. His explanation was quite general regarding the economics of building generation facilities, and did not seem to indicate specifically why the 4 C.P. method is an appropriate allocation methodology given that most of KCPL's production related plant after Wolf Creek is included will be base load.

KCPL witness Knodel claims that if different allocation factors are used in different jurisdictions, part of KCPL's production and transmission plant may not be allocated to any jurisdiction, and KCPL will not be able to recover the costs of that plant. (Knodel, TR. Vol. XVI, p. 4488). On cross-examination by staff counsel, KCPL witness Knodel agreed that if the Missouri Public Service Commission were to adopt the allocation ratio that KCPL proposes for the Missouri jurisdiction, and if the Kansas Corporation Commission were to adopt the allocation ratios that KCPL proposes for Kansas, for wholesale customers, and for transmission service loss, then KCPL will recover more than 100 percent of its production related costs. Mr. Knodel indicated that is due to the use of different test periods in the two jurisdictions. (Knodel, TR. Vol. A-3, p. 545-597).

In his rebuttal testimony, Mr. Sullivan reiterates KCPL's recommendation that the Commission adopt the 4 C.P. demand allocator for production capacity costs. He recommends this as a compromise between the 12 C.P. allocator proposed by the Kansas Commission staff and the 1 C.P. demand allocator proposed by the Missouri staff. He faults Mr. Marker's use of the 12 C.P. demand allocator by criticizing Mr. Marker's approach to pricing. However, on cross-examination he admitted that Mr. Marker did not testify with regard to pricing, but rather with regard to costing. In Mr. Sullivan's view, decisions to use or not use KWH during off-peak periods have little effect on system investment cost whereas decisions to use or not use KWH during peak periods have substantial impact on system investment costs. He explained that KCPL wants to increase load factor so that it can decrease the average cost per KWH. In his opinion the primary consideration for investment in generating capacity is the need to meet system peak demand. The 4 C.P. allocator, in his opinion, better reflects the primary cost causative factor in KCPL's investment in production.

Case No. ER-2026-0143
Schedule KM-s3
Page 6 of 12

He cites a Federal Energy Regulatory Commission (FERC) proceeding in which the FERC adopted a 4 C.P. methodology, but does not indicate that this Commission is bound by the FERC findings. Mr. Sullivan also asserts that, not only system design, but also fuel diversity, is a consideration that led to the construction of Wolf Creek. On cross-examination Mr. Sullivan admitted that fuel diversity is not justified at <u>any</u> cost. Staff asserts that Wolf Creek is a very expensive generating facility for the company to build just to obtain fuel diversity.

Mr. Sullivan also expressed concern that KCPL would not recover all of its production investment in its Wolf Creek cases because of inconsistent production allocation methods used in Missouri and Kansas. Yet he didn't disagree with Mr. Knodel's testimony that if the Missouri and Kansas Commissions adopt certain of KCPL's proposed allocators, then KCPL could be recovering slightly more than 100 percent of its total investment.

On cross-examination from Chairman Lennen about what would be the merit in allocating base load production plant on a 12 C.P. method, and peaking plant on a different allocator, Mr. Sullivan replied that he would have to consider that impact on pricing. He stated that the 12 C.P. method incorporates a great deal of equity considerations. However, he doesn't think that equity and costing should be mixed too early in the process. (TR. Vol. A-5, p. 1242-1244).

Staff urges the Commission to continue use of the 12 C.P. allocation methodology for several reasons: (1) the 12 C.P. method recognizes that utilities incur production capacity costs to serve load year round, not just the four summer peaking months; (2) the present rate application is due primarily because of the expected commercial operation of a major base-load plant (WCGS); and (3) 98.6 percent of KCPL's production investment consists of base load plant. These reasons make the continued use of the 12 C.P. methodology more logical and more reasonable than using the 4 C.P. methodology.

THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

Before Commissioners: Michael Lennen, Chairman;
Margalee Wright and Keith R. Henley

In the Matter of a General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas	DOCKET NO. 120,924-U
In the Matter of the Application of Kansas City Power & Light Company Requesting Proposed Changes in its Charges for Electric Service	DOCKET NO. 142,099-U 84-KCPE-198-R

ORDER

NOW, the above captioned matters come before the State Corporation Commission of the State of Kansas for consideration and determination of the application of Kansas City Power and Light Company (KCPL, or Applicant), for approval of changes in its charges for electrical service. Chairman Michael Lennen, Commissioner Margalee Wright, and Commissioner Keith R. Henley presided at the hearing on the application.

Having considered the evidence and testimony, the files and records and being fully advised in the premises, the Commission's findings and conclusions are set forth herein below.

I. APPEARANCES

1. The following parties entered appearances in the above captioned matters.

For the Applicant, KCPL,

Mr. Warren B. Wood
Legal Counsel
Kansas City Power and Light Company
8730 Neiman Road
Overland Park, Kansas 66214

Mr. A. Drue Jennings
Mr. Mark C. Sholander
Mr. Mark G. English
1330 Baltimore
Kansas City, Missouri

1. When a rate of return of 11.236 percent is applied to the previously adopted Kansas jurisdictional rate base of $409,958,000, the result is an operating income requirement of $46,063,000. When compared to test year operating income as adjusted and adopted herein, we find applicant has additional operating income requirements totaling $16,971,000. Assuming an appropriate income tax factor, applicant's gross annual revenue deficiency is $33,703,000 (before fuel savings), as calculated in the Appendix to this order.

2. Applicant, Staff and Johnson County Joint Intervenors presented testimony on the phase-in of the rate increase arising from this case. Witnesses for all three parties agree that a phase-in was desirable to avoid a sudden sharp increase in rates. They disagreed, however, on what percentage increase would justify a phase-in and what period of time should be used.

3. The Commission does not find it necessary to further summarize the evidence on this issue since we conclude that a phase-in of the rate increase we approve herein is not necessary or desirable. After fuel savings, KCPL ratepayers will realize an increase in rates of approximately 16 percent. We recognize that this increase cannot be said to be insignificant. However, we do believe that it is manageable and does not represent the kind of rate shock which the parties envisioned as requiring mitigation through phase-in. Our conclusion is also based on the fact that a phase-in, because of the accrual of carrying costs on deferred revenues, eventually increases the total cost to ratepayers. In balancing such considerations, we conclude a phase-in should not be ordered.

G. JURISDICTIONAL ALLOCATIONS

1. Currently KCPL's jurisdictional rates are based on a 12 coincident peak (C.P.) allocation factor, pursuant to this Commission's last KCPL rate order dated March 29, 1983, (Docket

No. 133,002-U). In that order the 12 C.P. method was found superior to the company's 4 C.P. method because the former recognizes investment in base load facilities which are utilized year round and not solely during the summer peak months.

2. In the present rate case, KCPL's witnesses Knodel and LaCapra recommended that production capacity costs be allocated among jurisdictions based on the average of the four coincident summer maximum peak loads. Mr. LaCapra testified that the summer peak is KCPL's central planning concern in assessing the need for new capacity. KCPL's rebuttal witness Sullivan, recommended the 4 C.P. demand allocator as a compromise between the 12 C.P. allocator proposed by the Kansas Commisission staff and the 1 C.P. allocator proposed by the Missouri Commission staff. He expressed concern that KCPL might not recover all of its investment if different jurisdictions use different production allocators. Yet Mr. Knodel acknowledged that if KCPL's proposals were adopted in Kansas and in Missouri, KCPL could recover slightly more than 100% of its total investment based on the different test years used in the two jurisdictions. Mr. Sullivan noted that the F.E.R.C. had adopted the 4 C.P. method. He concluded that the 4 C.P. allocator better reflects the primary cost causative factor in KCPL's investment in generating capacity that is, the need to meet summer peak.

3. Staff witness Marker opposed the 4 C.P. method stating it does not recognize the capacity requirements associated with the eight non-summer months. He recommended that KCPL's production and transmission plant be allocated among the jurisdictions by means of a 12 C.P. allocator because such an allocator recognizes the capacity requirements in all twelve months of a year. Mr. Marker testified that a utility determines the type and cost of its capacity by means of the total loads during all twelve months of the year, not just the annual system peak load. He explained that system peak load may determine the

total amount of generation capacity, but not the type and cost of that capacity. To illustrate his point, Mr. Marker noted that with the inclusion of Wolf Creek, 98.6 percent of KCPL's total production rate base is base load capacity on a dollar investment basis; and that on a KW basis, 85.4 percent of KCPL's production capacity is base load. Further he testified that KCPL's net investment in base load plant is $697 per KW, while its net investment in other plant is only $57 per KW.

4. We note that KCPL has filed this rate application because of the anticipated commercial operation of the Wolf Creek Generating Station (WCGS). KCPL's witnesses, Mr. Doyle, Mr. LaCapra, and Mr. Sullivan, acknowledged that WCGS is a base load unit. The issue before us is how to allocate production and transmision plant among the jurisdictions to reflect what portion of that plant is dedicated to the Kansas jurisdicional ratepayers, and therefore, should be paid by them. This is not an issue of pricing to manage load. As Mr. Marker has testified, with the addition of WCGS, production rate base will be 98.6 percent base load capacity. Earlier in this order we have set forth our findings regarding the valuation of the WCGS for ratemaking purposes. Even in view of these decisions, KCPL's investment in base load facilities will be greater than 94% of its total investment once Wolf Creek is included. (TR. Vol. A-4, p. 881). It is clear that KCPL did not invest in WCGS to serve only summer peak load. Therefore, we find that the 12 C.P. allocation factor is an appropriate method of allocating KCPL's production and transmission plant among jurisdictions. This method better recognizes KCPL's investment in base load facilities used year round, and not solely during the summer peak months.

Class C.O.S.

1. KCPL used a 4. C.P. allocator in its class cost of service. Mr. Marker testified that a 12 C.P. allocator was more

3. Each specific finding of fact made above is hereby adopted as an ultimate finding and conclusion of law by this Commission;

4. KCPL's application is hereby granted in part and denied in part, and the Commission authorizes and orders applicant to file rates and tariffs to produce additional gross revenue in the amount of $25,103,000, as calculated in the Appendix attached to this order, in accordance with the findings of the Commission;

5. Rates resulting from authorized revisions, as herein directed, will be fair, just, reasonable and sufficient and will not be unduly discriminatory or unduly preferential so that the same may be accepted upon their filing without formal objection by staff; said authorized new rates and charges shall be effective on sales rendered on or after approval by the Commission of the revised tariffs.

6. Applicant is further ordered to comply with all the Commission's directives and orders set forth herein.

Dated: September 27, 1985

Lennen, Chmn.; Wright, Com.; Henley, Com.

Judith McConnell
JUDITH MCCONNELL
EXECUTIVE SECRETARY

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