independently, but finds Staff's five-year amortization more reasonable that those proposed by Evergy, OPC or MECG. The regulatory asset is not so large as to necessitate use of a longer amortization period. Further, although the two accounts will not be netted, there will be a credit to rates from the amortization of the regulatory liability to offset to a large extent the amortization of the unrecovered investment. Thus, rather than the five-year amortization period proposed by Staff, the Commission finds it appropriate to set the amortization period for the unrecovered investment in the Sibley Units at four years to mirror the amortization period of the regulatory liability account.

AMI-SD

Findings of Fact:

102. Automated Meter Infrastructure (AMI) is an integrated system of smart meters, communication networks, and data management systems that enables two-way communication between utilities and customers.[138]

103. AMI meters measure and record electricity usage hourly or sub-hourly. Depending on the manufacturer and model of the AMI meter, other capabilities may be available such as monitoring the on/off status of electric service, measuring voltage, and remotely disconnecting and reconnecting electric service.[139]

104. EMM and EMW initially began replacing their existing automated meter reading (AMR)[140] meters with AMI meters in portions of its service territories from 2014 to 2016.[141]

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[138] Ex. 211, Eubanks Direct, p. 3.
[139] Ex. 211, Eubanks Direct, p. 3.
[140] AMR meters allow reading from a handheld device or vehicle, within a certain distance from the meter. To contrast, AMI meters can be read from anywhere there is an internet connection.
[141] Ex. 211, Eubanks Direct, p. 3.

105. Evergy historically has installed AMI meters that have different capabilities.[142]

106. Evergy first began installing AMI meters with remote service disconnect and reconnect, commonly referred to as AMI-SD meters, in 2017.[143]

107. **As of September of 2018, EMM's AMI meter penetration was approximately 98% and EMW's was somewhat less than 60%.**[144]

108. From November 1, 2018, through May 31, 2022, 87% of the meters exchanged were less than 7 years old.[145]

109. During the test year and update period (through December 2021), EMM exchanged 49,647 meters and EMW exchanged 22,235 meters. Of the exchanged meters, 99% of meters exchanged were less than 7 years old.[146]

110. Some of the AMI-SD meters installed during 2019 and 2020 were replacing manual meters as part of the rural EMM AMI meter exchange.[147]

111. Staff raised a concern regarding Evergy's premature retirements of the AMI meters still having a significant portion of remaining life being removed and replaced with AMI-SD meters.[148]

112. At the time of the initial deployment of AMI, AMI-SD meters were cost prohibitive, more than double the cost of the meters that were installed and nearly 25% higher than prices available today for AMI-SD meters.[149]

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[142] The specifics regarding the manufacturer and model type is confidential and is not at issue except for those meters with the service disconnect and reconnect functionality.
[143] Ex. 21, Caisley Rebuttal, p. 11.
[144] Ex. 211, Eubanks Direct, p.4.
[145] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 5.
[146] Ex. 211, Eubanks Direct, p. 5.
[147] Ex. 306 - EMW, Marke Direct, p. 15 (see table); Ex. 306 – EMM, Marke Direct, p. 9 (see table).
[148] Ex. 211, Eubanks Direct, p. 7.
[149] Ex. 21, Caisley Rebuttal, p. 10.

113. The AMI meters installed in 2014 to 2016 had a design life of 20+ years.[150] Evergy testified that the AMI meters installed in 2014-2016 still had design life left.[151]

114. Based on Account 370.02 Meters - AMI Distribution in the 2018 true-up accounting schedules through June 30, 2018, EMM had a Missouri Jurisdictional plant-in-service of $33,812,886 with an accumulated reserve of $4,081,223. This compares to a plant-in-service of $61,650,283 with an accumulated depreciation reserve of $3,211,002 based on Staff's direct accounting schedules through May 31, 2022.[152]

115. Based on Account 370.02 Meters - AMI Distribution in the 2018 true-up accounting schedules through June 30, 2018, EMW had a Missouri Jurisdictional plant-in-service of $21,777,871 with an accumulated reserve of $1,230,040. This compares to a plant-in-service of $49,178,779 with an accumulated depreciation reserve of $2,472,035 based on Staff's direct accounting schedules through May 31, 2022.[153]

116. OPC's witness Robinett indicated that the changes in plant in service and accumulated depreciation mean that the amount of early retirements has outpaced annual depreciation expense accrual which can be seen by a reduction in the total accumulated depreciation reserves from 2018 to 2022. This is not typical with an increase in plant-in-service over the same period. It would have been expected that depreciation reserve would have continued to increase and should have increased more with the additional plant that was added.[154]

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[150] Ex. 211, Eubanks Direct, p. 5.
[151] Ex. 21, Caisley Rebuttal, p. 9.
[152] Ex. 310, Robinett Rebuttal, p. 6.
[153] Ex. 310, Robinett Rebuttal, p. 7.
[154] Ex. 310, Robinett Rebuttal p. 6.

117. **Evergy has not recorded the AMI meters on the books as 'old' or 'new' nor** do they intend to open up a new subaccount for the new meters.[155]

118. Evergy intends to complete the replacement of AMI meters with AMI-SD meters by the end of 2024,[156] and possibly as early as the end of 2023.[157]

119. Evergy states the AMI meters were replaced with AMI-SD meters for technology reasons.[158]

120. The current AMI meters are not being replaced because they are at the end of their useful life but instead to make it easier for customer to be disconnected.[159]

121. AMI-SD reconnect functionality allows customers to get service connected within minutes, nearly 24 hours a day, seven days a week.[160]

122. To be reconnected currently, it can take one to three days, depending on the timing of the request being after hours or including non-business days.[161]

123. Remote disconnect and reconnect addresses safety concerns for the Evergy workers currently physically performing the disconnection, such as dogs, poison ivy, vehicle accidents, or angry confrontations.[162]

124. Before replacing the AMI meters with AMI-SD meters, Evergy reviewed the prospect by conducting a business case, and also analyzed the financial impact to customers from two different perspectives.[163]

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155 Ex. 306 - EMW, Marke Direct, p. 20; Ex. 306 – EMM, Marke Direct, p. 14.
156 Ex. 211, Eubanks Direct, p. 7.
157 Tr. Vol. 9, p. 381.
158 Ex. 21, Caisley Rebuttal, p. 10.
159 Ex. 306 - EMW, Marke Direct, p. 22; Ex. 306 – EMM, Marke Direct, p. 16.
160 Ex. 21, Caisley Rebuttal, pp. 11-12.
161 Tr. Vol. 9, p. 390.
162 Tr. Vol. 9, p. 391.
163 Ex. 21, Caisley Rebuttal, pp. 9-10.

125. The first financial review evaluating the cost to purchase and install AMI-SD meters was based on the proposed change-out schedule and the short-term and on-going O&M savings that would be realized due to the additional capabilities the AMI-SD meters could provide to make operations more efficient. The results indicate that from a financial perspective, customers would be indifferent to the AMI-SD meter change.[164]

126. The second financial review calculated the present value of the AMI meters installed in 2014 at $76 per meter plus the cost to install an AMI-SD meter in 2021 at $125 per meter. This was then compared to the cost of an AMI-SD meter in 2014 at $165 per meter. The present value comparison indicated that installing the AMI meter without SD capabilities in 2014 plus installing an AMI-SD meter in 2021 was less expensive than if the Evergy would have installed AMI-SD meters in 2014.[165]

127. **Staff's assessment** of the first financial review conducted by the Company is that it does not demonstrate that there are net cost savings to the AMI-SD meter rollout and it does not include the useful life remaining of the existing AMI meters in its calculations. For the second financial review, Staff assesses that the review simply considers whether or not it would have been a better financial decision for the Company to install AMI-SD meters in 2014; however, no party is suggesting Evergy should have installed AMI-SD meters in 2014.[166]

128. Staff also raised concerns about the inputs assumed by Evergy in preparing its business case analysis, including the depreciation rate used, personnel needs, and contractual obligations.[167]

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[164] Ex. 21, Caisley Rebuttal, pp. 15-16.
[165] Ex. 21, Caisley Rebuttal, pp. 15-16.
[166] Ex. 262, Eubanks Surrebuttal and True-up, p. 6. The 2014 installation of AMI meters is not being challenged as imprudent.
[167] Ex. 262C, Eubanks Surrebuttal and True-up Direct, pp. 7-8 (The Commission notes the particular information is confidential, and thus will not be restated).

129. Calculating the cost of the new AMI-SD meters must include the cost of the previous AMI meter that is not fully depreciated as well as the cost of labor associated with both the installation of the previous AMI meter and the installation of the new AMI-SD meter.[168]

130. OPC witness Dr. Marke's assessment of the first financial review is that it omitted a critical variable in the analysis, which was the undepreciated balance of the old AMI meters. The exclusion of the undepreciated balance would indicate that it is no longer a cost to the customers. However, this is not as reflected in Evergy's proposed rate base, which includes the old AMI meter along with the new AMI-SD meter that replaced it, as well as software in rate base.[169]

131. Evergy presented several benefits of the AMI meters.[170]

132. None of the benefits that would flow to EMM or EMW from the use of AMI-SD meters were quantified.[171]

133. The reasons for the individual meter exchanges during the test year, as provided in Evergy's field notes, were broken down by Staff into categories in descending order of the most common to least common as follows:

a. To exchange an AMI meter with an AMI-SD meter;

b. To exchange an AMI meter with an AMI-SD meter due to customer arrears;

c. Communication issues;

d. Unknown reasons;

e. Net meter installations;

[168] Tr. Vol. 9, p. 425
[169] Ex. 308, Marke Surrebuttal, p. 31.
[170] Ex. 49, Lutz Direct, pp. 36-39; and Ex. 117, Lutz Direct, pp. 36-39.
[171] Tr. Vol. 9, p. 435 - 436

f. Other (damaged or failing meters, access issues, and customer-requested exchanges).[172]

134. Staff recommended disallowances of meter exchanges where the reason identified in the field notes was for one of the three reasons - (1) the exchange was for the purpose of exchange (category a); (2) when the exchange was due to customer arrears (category b); and (3) for unknown reasons (category d).[173]

135. Evergy testified to the benefits to the customer and the Company of prioritizing customers with balances in arrears for meter exchange. Evergy forecast that post-COVID, an atypically high number of customers would have balances in arrears. Evergy was concerned that if a high number of customers were disconnected, many of them could end up waiting hours for reconnection once a payment was made or a plan established. Evergy argued that meter exchanges to AMI-SD meters for customers with balances in arrears was to ensure that they could be more quickly restored to service with an AMI-SD meter than with a technician physically present to restore service.[174]

136. The meter exchanged for "unknown reasons" could come from two places – an order entered without comments or field personnel deciding on a meter exchange while on location. Field personnel making this type of exchange is considered a "pick-up" order by Evergy's system, without a way to enter the reason for the exchange.[175]

137. Staff adjusted its recommended initial disallowance to remove meter exchanges that were listed in the unknown category when there was a meter reader or field employee request for the exchange.[176]

[172] Ex. 211, Eubanks Direct, pp. 5-6.
[173] Ex. 211, Eubanks Direct, p. 6.
[174] Ex. 21, Caisley Rebuttal, pp. 18-19.
[175] Ex. 21, Caisley Rebuttal, p. 21.
[176] Ex. 262, Eubanks Surrebuttal and True-up Direct, pp. 4-5.

138. While it is reasonable and necessary to replace a meter that is damaged or failing; given that the vast majority (99%) of AMI meters exchanged for AMI-SD meters were less than 7 years old, it is not reasonable to replace a meter solely to gain a new capability or when there is seemingly no reason.[177]

139. Staff recommends that the Commission disallow $6,321,846 for EMM and $2,957,124 for EMW FERC Account 370.2, respectively.[178]

140. Staff multiplied the number of meters per category of recommended disallowance by the cost per meter (depending on meter type) to arrive at its recommended disallowance.[179]

141. **OPC's cursory review of Evergy's PISA filings suggest that both EMM and** EMW may have exceeded the statutory limits on smart meter investment in 2020 for EMM and 2019 for EMW. OPC recommended that this be added to the list of issues where OPC can provide a recommendation in its position statement.[180]

Conclusions of Law:

No additional Conclusions of Law are necessary.

Issues Presented by the Parties:

A. Should the Commission approve a disallowance related to the replacement of AMI meters with AMI meters that have the capability to disconnect/reconnect service (AMI-SD)?

B. Should the Commission order Evergy Metro to change its deployment strategy so that it no longer prioritizes customers in arrearage?

C. Did Evergy exceed the 6% annual PISA spend limit on AMI meters?

1. If yes, what actions, if any, should the Commission take in response?

[177] Ex. 211, Eubanks Direct p. 6.
[178] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 3.
[179] Ex. 262, Eubanks Surrebuttal and True-up Direct, p. 3.
[180] Ex. 308, Marke Surrebuttal, pp. 42-43.

Decision:

The Commission agrees with Staff's position that the premature retirement and replacement of AMI meters that still function with AMI-SD meters was not prudent. The Commission therefore will order a disallowance of the AMI-SD meters installed for the three reasons **established in Staff's estimate, which were** (1) exchange of AMI meter for AMI-SD meter; (2) exchange of AMI meter for an AMI-SD meter due to customer arrears; and (3) unknown reasons.

Evergy witnesses testified that prioritizing customers with balances in arrears for meter exchange was a benefit to customers and the Company. Evergy argued that with the possibility of large numbers of disconnections post-COVID, it was beneficial to those customers in arrears (and thus more likely to experience an involuntary shut-off) because they could more quickly have electricity restored if shut-off. The Commission does not find this rationale credible. Replacement of functioning meters with significant remaining life is, without further valid justification, not just and reasonable.

Installing an AMI-SD meter for the purpose of installing an AMI-SD meter is not a prudent reason for a meter exchange when the meter being taken out is likely only 7 years into a 20-year depreciable life. This reasoning is not improved by prioritizing customers in arrears. Similarly, after being adjusted to remove those meters exchanges initiated by the Evergy field personnel, the meters exchanged for unknown reasons were not sufficiently supported in evidence with valid reason for the exchange of an AMI meter with substantial life remaining. The Commission finds that Evergy has not met its burden of proof regarding the meter exchanges for the three reasons outlined by Staff.

OPC recommended a disallowance of all AMI-SD meters. The Commission disagrees as OPC's recommendation is premised on the assumption that the installation of AMI-SD meters was unjustified and provided no benefit. The Commission does not question the overall benefits provided by AMI-SD meters over AMI meters. There is value in the upgraded technology and benefits provided with the AMI-SD meter. In this case, the benefits of the AMI-SD meters provide value when installed for justifiable reasons, such as replacing manual meters, or an AMI meter that is not functioning.

OPC also presented a question in surrebuttal testimony that Evergy, in purchasing the AMI-SD meters, may have exceeded its PISA limit. However, testimony stated it was based on a cursory review and only recommended further discussion. Of concern to the Commission is that the testimony only suggests that this may be an issue. The lack of evidence regarding this issue precludes a Commission decision at this time.

SUBSCRIPTION PRICING

Findings of Fact:

142. EMM and EMW proposed an opt-in Subscription Pricing Pilot Program (Subscription Pricing).[181]

143. Evergy has conducted customer surveys regarding Subscription Pricing.[182]

144. The first survey consisted of 39 customers, and the second survey was online.[183]

145. One of the questions posed in Evergy's first survey was "do you want unlimited electricity for a fixed price?"[184]

146. Evergy explained that they referenced an "unlimited" electric plan so that the survey participant can draw a comparison with other "unlimited" plans consumers are

[181] Ex. 37 (EMM), Hledik Direct, p. 3; and Ex. 112 (EMW), Hledik Direct, p. 3.
[182] Tr. Vol. 10, p. 636.
[183] Tr. Vol. 10, p. 629.
[184] Tr. Vol. 10, pp. 636-637.

traditionally familiar with, such as their subscription with Netflix or wireless phone provider. In other words, the consumer is not charged on a per unit basis (number of movies watched or number of minutes used). They are charged on a flat, monthly price.[185]

147. Evergy stated it will not market or promote subscription pricing to customers as an "unlimited" rate plan.[186]

148. Evergy also distinguished that it was the 2021 customer survey that mentioned the word "unlimited". Evergy states the June 2022 customer survey presented the option as a "Flat Pricing Plan" and was still desired by customers.[187]

149. The description of Flat Pricing that was given in the survey compared it to an unlimited plan for an unrelated subscription service, specifically using the word "unlimited".[188]

150. Subscription Pricing would provide residential customers with an entirely fixed monthly electric bill, similar to subscription-based services and club memberships.[189]

151. Subscription Pricing removes pricing signals important to programs like cost-based and time of use rates.[190]

152. Subscription Pricing's fixed bill would be based on historical usage of the previous twelve months of weather normalized usage. The customer's bill would remain

[185] Ex. 84, Winslow Surrebuttal, p. 20.
[186] Ex. 84, Winslow Surrebuttal, pp. 20-21.
[187] Ex. 84, Winslow Surrebuttal, pp. 20-21.
[188] Ex. 84, Winslow Surrebuttal, p. 20; Ex. 22, Caisley Surrebuttal, Confidential Schedule CAC-5, p. 35 of 42.
[189] Ex. 37, Hledik Direct, p. 3; and Ex. 112, Hledik Direct, p. 3.
[190] Tr. Vol. 10, p. 619, 18-23.

unchanged for a one-year term. After each one-year term, the usage would be re-averaged for the next one-year term, but there is no true-up.[191]

153. Evergy's customer survey reflected interest in the program for moderate-income households seeking a stable electric bill but renters and low-income customers did not find this plan to fit their lifestyle.[192]

154. Evergy is a monopoly that provides an essential service and does not provide competitive non-essential services like gym memberships or streaming entertainment services.[193]

155. There are thirteen utilities in the United States offering a subscription pricing program.[194]

156. Subscription Pricing, as proposed, is a complex pricing process with a behavioral usage adder, a program cost adder, risk premium adder, efficiency incentive, and other add-on options.[195]

157. Subscription Pricing uses weather normalization applied by class to calculate a given Subscription Pricing enrollee's bill.[196]

158. Customers of Subscription Pricing would, on average, pay more under Subscription Pricing than they otherwise would under a standard rate.[197]

159. Evergy seeks waivers of certain mandated billing and payment standards set by Chapter 13 of the Code of State Regulations.[198]

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[191] Ex. 37, Hledik Direct, p. 5 and 19; and Ex. 112, Hledik Direct, p. 5 and 19.
[192] Ex. 82, Winslow Direct, pp. 22-23.
[193] Ex. 242, King Rebuttal, p. 12.
[194] Tr. Vol. 10, p. 504.
[195] Ex. 242, King Rebuttal, p. 12; and see Tr. Vol. 10, pp. 500-503, and 580-581.
[196] Tr. Vol. 10, pp. 578-579.
[197] Ex. 323, Kremer Rebuttal, Schedule LAK-R-6; and see Tr. Vol 10, pp. 512-517.
[198] Ex.242, King Rebuttal, pp.11-12.

160. Customers may not be able to understand the complex structure of all of the components which make up the ultimate flat rate offered by the Subscription Pricing program.[199]

161. A level pay tool already exists for Evergy customers in the form of the Average Payment Plan.[200]

162. Average Payment Plan participants are exposed to weather-related fluctuations changes in usage, which is different from the proposed Subscription Pricing Plan.[201]

163. OPC recommended a disallowance for the fees associated with Evergy's consultant testimony in regards to Subscription Pricing, stating it is out-of-line with Commission policy.[202]

Conclusions of Law:

No additional Conclusions of Law are necessary.

Issues Presented by the Parties:

A. Should the Commission approve the proposed Subscription Pricing Pilot Program?

B. Should the Commission grant Evergy's request for variances to Chapter 13.020 Billing and Payment Standards, which the Company states is needed to implement Evergy's proposed Subscription Pricing Pilot Program?

C. Should the Commission disallow costs related to consultant fees associated with Evergy's Subscription offering?

[199] Ex. 38, Hledik Surrebuttal, pp. 10-11.
[200] Ex. 323, Kremer Rebuttal, p. 14 and 16.
[201] Ex. 38, Hledik Surrebuttal, p. 8.
[202] Ex. 307, Marke Rebuttal, p. 21.

Decision:

Evergy argues that its two surveys show that customers want Subscription Pricing. A question in the first customer survey mentions unlimited energy and only involves thirty-nine customers. The second survey was conducted online. While the second survey can be interpreted to show that customers prefer what the survey calls "Flat Pricing" when offered a choice among the several of Evergy's proposed rates. However, the description of Flat Pricing that was given in the survey used the word "unlimited" and compared Flat Pricing to a plan for an unrelated subscription service. In addition, the results of the survey showed the preference for this type of plan was skewed towards moderate-income households but not renters and low- income customers. While every utility offering may not be preferential for every customer type, alienating a specific customer group which is already at a disadvantage further erodes the desirability of this proposal. The Commission does not find the results of either survey to be credible support for Subscription Pricing.

Subscription Pricing, by Evergy's own admission, removes elements such as weather-related fluctuations in usage which operate as pricing signals to customers in conjunction with rate structures such as TOU rates. The success of TOU rates could be undermined by participation in a program structured like Subscription Pricing.

There is also the unchallenged fact that Subscription Pricing will likely result in higher bills for participants. Because Subscription Pricing, absent other factors, is more likely than not to result in higher bills to customers, the Commission finds it would likely result in unjust and unreasonable rates.

The Commission has set rules that offer protections to utility customers for billing structure to ensure that customers understand what they are being billed and the reasoning for those charges. Evergy asks for variances from these rules to offer customers a bill that reflects only the price of service, but not the detailed breakdown behind it. Evergy by its witness' own admission expects that customers would not comprehend all of the details comprising their bills under the Subscription Pricing program proposal. The Commission is further not persuaded that the Program or its waivers are appropriate.

OPC recommended the Commission disallow the costs of the consultant who testified and put together the Subscription Pricing proposal. OPC argues that the rate design is inherently illegal and so out-of-line with Commission policy that ratepayers should not have to pay for the consultant's testimony supporting that rate design. The Commission is not fully persuaded by OPC's argument, and finds it appropriate to divide the cost equally between shareholders and ratepayers. While this proposed pilot program was ultimately rejected, the Commission does not want to stifle innovation. Therefore, the Commission finds it appropriate that both shareholders and ratepayers should contribute to the cost of this proposal and will disallow 50% of the cost of the Subscription Pricing consultant.

RATE DESIGN/CLASS COST OF SERVICE

Findings of Fact:

164. Evergy's immediately preceding general rate case included an agreement regarding rate design issues, specifically supporting Time of Use (TOU) rates, but with no specific measurable goal or timeline.[203]

165. Starting immediately after its rate case approvals in 2018, the Company began executing on its commitments from the rate design agreement.[204]

[203] Ex. 82 (EMM), Winslow Direct, p. 5; and Ex. 128 (EMW), Winslow Direct, p. 5.
[204] Ex. 82, Winslow Direct, p. 5; and Ex. 128, Winslow Direct, p. 5.

166. Evergy then researched, developed, and implemented a 3-period, opt-in TOU rate plan (Whole House) for residential customers as a pilot.[205]

167. **Evergy's pilot resulted in 1.1% of the residential customers enroll**ed in TOU rates over a 20-month period.[206]

168. Evergy conducted surveys which showed customers wanted more rate options, but were hesitant regarding a mandatory TOU rate.[207]

169. Evergy in this case proposed new opt-in TOU rates with the primary goals of expanding customer choice; reducing system coincident peak demand; and aligning pricing structure with cost causation.[208]

170. For the existing 3-period TOU rate, Evergy proposed two adjustments to (1) align summer seasons to June 1 – September 30, and (2) reduce the non-summer price differentials to better reflect cost.[209]

171. The existing 3-period Evergy TOU rate has a 6-times price differential between the on-peak and super off-peak rate.[210]

172. Price differentials are ratios presented to reflect the pricing relationship between the TOU periods (on-peak vs off-peak). For example, 6:1 indicates that the on-peak price is 6-times the off-peak price.[211]

173. Evergy proposes three additional opt-in residential TOU rates – (1) a 2-period TOU rate; (2) a High Differential TOU rate to accommodate the charging patterns

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[205] Ex. 82, Winslow Direct, p. 5; and Ex. 128, Winslow Direct, p. 5.
[206] Ex. 49 (EMM), Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117 (EMW), Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[195] Ex. 23, Caisley Surrebuttal, pp. 6-7.
[208] Ex. 82, Winslow Direct, p. 7; and Ex. 128, Winslow Direct, p. 7.
[209] Ex. 82, Winslow Direct, p. 18; and Ex. 128, Winslow Direct, p. 18.
[210] Ex. 82, Winslow Direct, p. 17; and Ex. 128, Winslow Direct, p. 17.
[211] Ex. 83, Winslow Rebuttal, p. 2.

of EV drivers (High Differential EV TOU rate); and (3) a Separately Metered Electric Vehicle TOU rate which is identical to the High Differential TOU rate with the exception that customers need to have a separate meter for EVs.[212]

174. The Evergy 2-period TOU proposal has a 4-times price differential between on-peak and super off-peak during summer and a 2-times differential between on-peak and off-peak during winter.[213] This is a new rate proposal that would provide customers who have less ability to shift usage throughout the year an additional TOU rate option and mitigate the bill impact of the 3-period TOU rate typically occurring for space heating customers.[214]

175. The Evergy High Differential TOU rate and the Separately Metered Electric Vehicle TOU rate would both have a 12-times price differential for EMM and a 10-times price differential for EMW.[215]

176. Evergy sees the fundamental purposes of TOU rates to be price signaling of actual costs, and creation of elasticity in demand to improve efficiency of resources.[216]

177. **Staff did not support Evergy's proposed** opt-in TOU rates because Staff **viewed Evergy's TOU rates as** not being cost-based.[217] However, Staff stated that **Evergy's 2**-period TOU rate structure is the less objectionable of the residential TOU rates proposed by Evergy.[218]

178. Staff recommended the transition of EMM and EMW residential rate schedules to a default time-based rate structure consistent with two other Missouri

[212] Ex. 82, Winslow Direct, pp. 15-16; and Ex. 128, Winslow Direct, pp. 15-16.
[213] Ex. 82, Winslow Direct, p. 18; and Ex. 128, Winslow Direct, p. 18.
[214] Ex. 82, Winslow Direct, p. 16; and Ex. 128, Winslow Direct, p. 16.
[215] Ex. 82, Winslow Direct, p. 19; and Ex. 128, Winslow Direct, p. 19.
[216] Ex. 83, Winslow Rebuttal, p. 3.
[217] Tr. Vol. 11, p. 747.
[218] Ex. 243, Sarah Lange Rebuttal, p. 52.

utilities. The Union Electric Company d/b/a Ameren Missouri (Ameren Missouri) default TOU approach is a modest on-peak overlay included in the default residential rate design. The Empire District Electric Company d/b/a Liberty (Empire) default TOU approach employs a modest off-peak discount overlay and was also included in the default residential rate design.[219]

179. **Staff's recommended TOU** default rate during the summer is a one cent premium during on peak times, and an off-peak discount of one cent during off peak time. During non-summer months, the TOU is a one-quarter of one cent ($0.0025) premium during on-peak times, with the one cent off-peak discount remaining the same.[220]

180. **Under Staff's recommended TOU rate,** if a customer who uses approximately 1,000 kWh a month consumes a lot of their energy over night, they can expect to see their monthly bills go down by about $10 each month. If a customer who uses around 1,000 kWh a month consumes a lot of their energy in the afternoon and early evening, they can expect to see their bills go up by about $10 each month. If a customer is able to change when they use energy, they can save about $20 per month. But under **Staff's plan, no customer will have a** TOU-related bill increase of more than one cent per kWh in the summer, or one cent for each 4 kWh the rest of the year, and even that increase will only apply if that customer uses all of their energy between 4:00 p.m. and 8:00 p.m.[221]

[219] Ex. 229, Sarah Lange Direct, p. 17.
[220] Tr. Vol. 11, p. 746; Ex.265, Sarah Lange Surrebuttal, p. 34.
[221] Ex. 229, Sarah Lange Direct, p. 45.

181. **Staff witness Sarah Lange argues that Staff's proposed TOU rates is a** customer friendly approach, which will mitigate the impact of TOU rates to customers with energy-intensive HVAC units.[222]

182. Among investor-owned electric utilities in Missouri, TOU rates have been a recent addition and are not widespread.[223]

183. Even though opt-in TOU rate deployment is more common, some utilities have deployed TOU on an opt-out or mandatory basis, most of which were deployed in the last 2 years.[224]

184. States and commissions have adopted different approaches regarding opt-in versus opt-out TOU rates.[225]

185. Customer satisfaction under TOU remains high with either opt-in or opt-out. However, opt-out rates have higher enrollment rates relative to opt-in rates.[226]

186. The cost to provide energy to customers varies with the time of day due to demand, that is, competition for that energy. **The driver of Staff's low differential TOU rate** proposal is that energy generally costs more in certain time periods, and that historically ratemaking has not sufficiently recognized the cost-based difference of a kWh consumed at 6:00 p.m. versus being consumed at 2:00 a.m.[227]

[222] Ex. 229, Sarah Lange Direct, p. 41.
[223] Ex. 83, Winslow Rebuttal, p. 6.
[224] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[225] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[226] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 36-37 of 89.
[227] Ex. 229, Sarah Lange Direct, pp. 18-19.

187. Moving customer usage from on-peak to off-peak is beneficial, but was not **the driving design criteria of Staff's** TOU proposal.[228]

188. Third-party reviews show half of TOU rate price differentials are at least 10 cents per kWh. **Staff's recommended low differential** TOU rate of one cent per kWh is an outlier in the industry.[229]

189. Analysis of TOU programs show that as the price differential increases, customers shift usage in greater amounts.[230]

190. TOU rate designs are not well suited for customers with loads that cannot be shifted.[231]

191. Customers who do not save money at the level they expect under a TOU rate did not remain in the program.[232]

192. Among investor-owned electric utilities in Missouri, the price differentials are conservative – **Ameren Missouri's introductory rate was described as** a low differential, and Empire began offering a two-cent differential in October of 2022.[233]

193. One of the primary benefits of AMI meters is the ability to price electricity closet to the true cost of service through TOU rates.[234]

194. **Evergy witness Miller recommends Evergy's summer inclining block rate** with no further change for the default residential rate structure.[235]

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[228] Tr. Vol. 11, pp. 781-782.
[229] Ex. 83, Winslow Rebuttal, pp. 4-5.
[230] Ex. 83, Winslow Rebuttal, p. 5.
[231] Ex. 49, Lutz Direct, Schedule BDL-3, pp. 38 of 89; Ex. 117, Lutz Direct, Schedule BDL-3, pp. 38 of 89.
[232] Ex. 229, Sarah Lange Direct, p. 41.
[233] Ex. 83, Winslow Rebuttal, p. 6.
[234] Ex. 306 - EMW, Marke Direct, p. 16; Ex. 306 – EMM, Marke Direct, p. 10.
[235] Ex. 61, Miller Surrebuttal, p. 29.

195. **Staff witness Sarah Lange recommends that Evergy's summer inclining** block rare should be the default residential rate for customers who opt-**out of Staff's** proposed default TOU rates.[236]

196. Evergy recommends several changes to the residential class rate design to **"clean-up" the residential tariff.**[237] The rates to be eliminated were previously frozen.[238] These changes include the elimination of specific rates and transitioning those customers to existing rates.[239]

197. Staff agreed that duplicative rate codes should be eliminated, as most are the legacy of prior mergers and rate schedule consolidation that have become obsolete.[240]

198. To date, Evergy has completed more than 13 studies on TOU.[241]

199. Evergy has arguably had eight years to prep their customers for the value proposition of TOU rates since beginning installation of AMI meters.[242]

200. Given the customer education provisions of the 2018 stipulation,[243] EMM has spent $1,386,936 and EMW has spent $1,692,041 on TOU program costs, and EMM has spent $98,788 on customer education costs related to TOU and EMW has spent **$24,000. Therefore, Evergy's customers at large should be well**-educated on both the

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[236] Ex. 229, Sarah Lange Direct, pp.51-52.
[237] Ex. 59, Miller Direct, p. 3; and Ex. 119, Miller Direct, p.3.
[238] Ex. 59, Miller Direct, pp. 12-17; and Ex. 119, Miller Direct, pp.12-17.
[239] Ex. 59, Miller Direct, p. 3; and Ex. 119, Miller Direct, p.3.
[240] Staff Initial Brief, p. 34.
[241] Ex. 306 - EMW, Marke Direct, p. 7; Ex. 306 – EMM, Marke Direct, p. 7.
[242] Ex. 307, Marke Rebuttal, p. 14.
[243] "Non-Unanimous Partial **Stipulation and Agreement Concerning Rate Design Issues"** issued on September 25, 2018 in cases ER-2018-0146 and ER-2018-0145.

general economic underpinning and the potential bill impacts of rates that vary with the time of day at which energy is consumed.[244]

201. **The price differential ratio is the single biggest factor affecting a customer's** realized behavioral change.[245]

202. Staff proposed a residential customer charge for both EMM and EMW of $12.00. Staff calculated that amount by increasing the current EMM residential customer charge by the percentage adjustment of the EMM residential class revenue requirement, rounded to the nearest quarter.[246]

203. Evergy proposed a residential customer charge of $16 for both EMM and EMW.[247]

204. The residential classes will receive above-system-average rate increases.[248]

205. Raising the residential customer charge diminishes the customer incentive to be more energy efficient.[249]

206. Evergy witness Kimberly Winslow estimated that for each customer enrolling in one of its opt-in TOU programs it would take approximately $150 per in marketing and education costs, $150 in customer acquisition cost.[250] The only basis to **support the $150 customer acquisition estimate is a statement that it is based on Evergy's experience. If Evergy's opt**-in TOU rates are approved, it asks that it be authorized to

[244] Ex. 229, Sarah Lange Direct pp. 15-16.
[245] Tr. Vol. 11, pp. 719-720.
[246] Ex. 265, Sarah Lange Surrebuttal, pp. 30-31.
[247] Ex. 59, Miller Direct, p. 43; and Ex. 119, Miller Direct, p.34.
[248] Ex. 265, Sarah Lange Surrebuttal, p. 32.
[249] Tr. Vol. 10, p. 619.
[250] Ex. 82, Winslow Direct, p. 54; and Ex. 128, Winslow Direct, p. 54.

recover prudently incurred program costs at a not-to-exceed acquisition cost of $150 per customer.[251]

207. Providing optional programs that lose $150 per participant, to be spread out to other ratepayers is unreasonable.[252]

208. Evergy proposed changes for non-residential customers rate schedules, design and structure – (1) a new time-related pricing rate; (2) seasonal alignment (changing EMM to match EMW); (3) consolidation of rates/codes; and (4) elimination of select end use rates.[253]

209. Staff proposed a default TOU rate for non-residential customers using the same price differentials as proposed for the residential customers.[254]

210. Evergy witness Miller argues that Staff's non-residential TOU proposal does not consider the broad set of customers and the unique rate structures that exist across jurisdictions.[255]

211. Evergy has not had discussions with its commercial and industrial customers regarding the possibility of mandatory TOU rates.[256]

212. MECG opposed Staff's proposed default TOU rates for the large power service (LPS) and large general service (LGS) rates.[257] MECG's opposition is due to the lack of a rate to evaluate and a lack of information regarding an impact analysis of the proposed changes to the LPS and LGS customer classes.[258]

[251] Ex. 82, Winslow Direct, p. 54; and Ex. 128, Winslow Direct, p. 54.
[252] Ex. 243, Lange Rebuttal, pp. 2-3.
[253] Ex. 59, Miller Direct, pp. 45-47; and Ex. 119, Miller Direct, pp.34-39.
[254] Ex. 229, Sarah Lange Direct, p. 60.
[255] Ex. 61, Miller Surrebuttal, p. 30.
[256] Tr. Vol. 11, p. 711.
[257] Ex. 405, Maini Rebuttal, p. 4.
[258] Ex. 405, Maini Rebuttal, p. 12; Ex. 405, Maini Rebuttal, pp. 13-14.

213. Both OPC and MECG propose that Evergy should meet with stakeholders related to its rate modernization plan within 180 days after the effective date of rates in this case.[259]

214. Evergy meets with stakeholders on a periodic basis and is not opposed to discussing the rate modernization plan with interested parties.[260]

Conclusions of Law:

CC. In undertaking the balancing of interests required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[261]

Issues Presented by the Parties:

B.[262] What are the appropriate rate schedules, rate structures, and rate designs for the non-residential customers of each company?

D. What are the appropriate rate schedules, rate structures, and rate designs for the Residential customers of each utility?
1. What is the appropriate residential customer charge?

E. What measures are appropriate to facilitate implementation of the appropriate default or mandatory rate structure, rate design, and tariff language for each rate schedule?

F. Should the Company's **proposed Time of Use rate schedules be** implemented on an opt-in basis?

G. Should the Staff's proposed Time of Use rate schedules be implemented on a mandatory basis?

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[259] OPC Position Statement p. 30 and MECG Position Statement p. 16.
[260] Evergy Position Statement p. 36.
[261] *Federal Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942).
[262] The original lettering is retained here – the missing letters correspond to resolved issues.

K. Should the Commission order Evergy to meet with stakeholders related to its rate modernization plan within 180 days after the effective date of rates in this case?

L. Should Evergy work to improve the education of its customers regarding the billing options and rate plans it has currently?

Decision:

Residential Rates, Schedules and Structures; Opt-In Versus Opt-Out; High Price Differential Versus Low Price Differential; and Customer Education

Several of the parties to this case are supportive of TOU rates in general. The disagreements form around opt-in versus opt-out and a high price differential versus a lower price differential. The Commission sees a benefit in incorporating a mix of these approaches.

Evergy proposes four opt-in TOU rates for residential customers, which reflect higher differentials than Staff's lower TOU rate proposal. A high differential allows higher levels of savings for those customers who are able to change their energy usage times. Evergy's opt-in approach is based on the recommendation to provide its customers with the option of selecting the rates that work for them. Under this approach, Evergy's base default rates would be the standard flat rates. One of the primary benefits of AMI is the ability to provide customers with TOU rates. Given eight years of experience with AMI, millions of dollars invested in AMI across Evergy's footprint and many studies regarding TOU rates, the Commission is concerned with taking the status quo approach that currently reflects only minimal (1.1%) residential adoption of TOU rates.

Staff's recommendation included a low differential opt-out TOU rate in the form of an approximately two-cent swing between on- and off-peak pricing. Staff's proposal uses a low differential rate to offer more protection for the customers that cannot change usage times. The basis for Staff's low differential proposal is that it is the "training wheels" approach for introducing TOU rates to customers that currently are not and have never been enrolled in Evergy's TOU pilot. The Commission finds Staff's approach of implementing TOU rates as a default or opt-out rate a better approach to introduce residential customer to TOU rates, since opt-out TOU rates result in higher enrollment. However, Staff's low differential rate, even though it would provide protections to some customers, does not provide sufficient incentive or opportunities for customers to see savings from TOU rates. Therefore, the Commission does not agree with Staff's low differential TOU rate being the introductory default TOU rate for residential customers.

Offering both high and low differential TOU rates will allow for more customer choice, will sufficiently introduce TOU rates to customers and will allow a higher differential rate to exhibit the benefits that derive from TOU rates. But the Commission also understands that allowing the option to opt-into a lower differential rate may better suit certain customers' lifestyles. As both Evergy's and Staff's proposals have multiple benefits, the Commission will authorize modified versions of both. The Commission finds Evergy's 2-period TOU rate to be the best introductory high differential TOU rate for residential customers as it has the lowest differential of Evergy's high differential TOU rates while still providing a benefit to those customers seeking substantial savings by altering the time of day of their energy consumption. Therefore, the Commission will order that Evergy's 2-period TOU rate be established as the default residential customer rate with Staff's low differential TOU rate as an opt-in TOU rate.

As Evergy's customer surveys show hesitancy regarding TOU rates, this 2-period high differential rate should take effect six months after the effective date of the tariff. The

Commission will order a six-month lead time to allow for further customer education and engagement regarding the new TOU rate offerings.

Evergy's additional proposed TOU rates (3-period TOU rate; the High Differential EV TOU rate; and the Separately Metered Electric Vehicle TOU rate) will further advance customer choice. The Commission finds these additional proposed TOU rates reasonable and will also approve them as opt-in rates. Customers will be assigned to the high differential rate automatically, and may opt-into either Staff's low differential, Evergy's 3-period, High Differential EV rate or Separately Metered EV rate. The Commission is not approving any traditional ratemaking structure for residential customers to be used after the six-month educational period.

Evergy has proposed the elimination of several residential rate codes, which were either previously frozen or are duplicative with other existing rate codes. Staff agrees with the removal of duplicative rate codes. Therefore, the Commission will order the elimination of the rate codes identified in this case.

To summarize, residential rates for Evergy are authorized to be Evergy's 2-period TOU proposed rate as the default rate beginning six months after the tariffs become effective. Staff's low-differential rate is approved as an opt-in rate, without a lead-in time. Evergy's additional residential TOU proposals are also authorized on an opt-in basis, without a lead-in time. Customers are authorized to opt-out of the default high-differential rate into one of the four additional TOU rates approved here. Existing 3-period TOU customers shall be allowed to stay on their existing TOU rate during the transition of non-TOU residential customers to the 2-period TOU rate. Evergy shall implement a program to engage and educate customers in the six-month lead-in time until its 2-period TOU rate takes effect as the default rate for residential customers. Evergy shall work with Staff and

OPC and permit them a chance to review materials related to the education program to ensure the program has a maximum potential for success. Further Evergy will eliminate the identified residential rate codes and transition customers to the identified existing codes.

<u>Net Customer Acquisition Cost</u>

Evergy proposed that the Commission authorize deferral for prudently incurred program costs, such as marketing, education, and administration, for its proposed residential TOU rates at a net customer acquisition cost of no more than $150 per customer. No other party was in favor of the net customer acquisition cost. There is no evidence in the record to suggest how the $150 was computed or to explain the need for a net customer acquisition cost. Furthermore, the Commission finds that if TOU rates are implemented on an opt-out basis instead of an opt-in basis as proposed by Evergy, there should be no acquisition process. The Commission is not persuaded that **it is "more likely than not" that the proposed** $150 net customer acquisition cost would be just and reasonable.

<u>Residential Customer Charge</u>

The Commission agrees with Staff's recommendation regarding the appropriate residential customer charge. As Evergy begins offering multiple TOU rates, it is important to foster customer interest, with one of the proven ways being to allow customers to impact their monthly electric bill. It is likely that significantly raising the residential customer charge will mute the TOU pricing signals such that interest or follow-through with TOU rates will wane as they cannot achieve their expected savings from TOU mitigation due to a higher customer charge. Ratemaking decisions are often interdependent, and the Commission'**s decision here is based on moving forward with**

TOU rates and authorizing a smaller increase than Evergy requested to the customer charge in order to foster the growth of the TOU rates. The Commission will re-evaluate the growth of the TOU programs and the monthly customer charge in Evergy's next rate case. In the present case, the Commission finds that $12.00 is the appropriate residential customer charge.

Non-residential Rates, Schedules and Structures

Given the unique make-up of non-residential customers, including small business, such as gas stations and restaurant, whose power consumption is customer driven, the Commission does not find Staff's proposed default TOU rate for non-residential customers appropriate without further study. The Commission agrees with Evergy's proposal. Evergy proposed a new Time-Related Pricing rate, seasonal alignment matching EMM to EMW, code consolidation and elimination of select end use rates. The Commission is persuaded that the expansion of rate offerings while simplifying the codes and end use rates will improve customer satisfaction, efficiency and will result in just and reasonable rates to non-residential customers.

Meeting with Stakeholders

The parties also presented the question of Evergy being ordered to meet with stakeholders related to its rate modernization plan. Evergy stated it meets with stakeholders on a periodic basis and is not opposed to discussing the rate modernization plan with interested parties. Therefore, the Commission memorializes here that this meeting shall occur.

RATE BASE and RESOURCE PLANNING

The Commission is combining the two issues involving coal-fired generation.

Findings of Fact:

215. Generally, Sierra Club faulted Evergy for using the results of its Depreciation Study to set unit retirement dates for its coal fleet. Sierra Club suggested instead an optimized capacity expansion model, which would allow the model to select retirement dates.[263]

216. Sierra Club stated that Evergy performed no optimized economic analyses on the projected performance of its coal fleet for its 2021 IRP.

217. Capacity expansion software is a tool that simply compares going-forward costs of the available alternatives and determine the lowest-cost option to meet capacity and energy requirements, subject to any modeling constraints (e.g., import limitations or annual build limits).[264]

218. As part of the joint resolution following the 2021 IRP, Evergy is utilizing capacity expansion modeling beginning with the 2022 Annual Update.[265]

219. Sierra Club asserted that Evergy has not demonstrated that continued investment in its coal fleet is the prudent and least-cost option to provide reliable power to ratepayers as part of these dockets or as part of its 2021 IRP.[266]

220. Sierra Club alleged that Evergy could retire one or even two of its existing coal units and would not need to replace the capacity for at least another decade.[267]

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[263] Ex. 450, Glick Direct, pp. 17-18.
[264] Ex. 56, Messamore Rebuttal, p. 13.
[265] Ex. 56, Messamore Rebuttal, p. 13.
[266] Ex. 450, Glick Direct, p. 4.
[267] Ex. 450, Glick Direct, p. 21.

221. **EMM has generation in excess of its customers' needs; while EMW does** not have enough SPP accredited generation capacity to meet its peak. Combined, the two have enough SPP accredited generation to meet the combined loads.[268]

222. Having enough capacity is essential to having enough energy to meet **customers' load requirements. However, having enough capacit**y does not necessarily ensure that energy will be available when it is needed. For instance, EMW does not have enough generation capacity through its owned resources and purchased power agreements to meet the SPP resource adequacy standards. It can only meet the SPP resource adequacy standards when combined with EMM. **EMW'**s resource plan depends on EMM to provide capacity and on SPP to provide energy.[269]

223. **EMM's generation produces revenue on the SPP energy market that offsets** fuel costs and some of its load cos**ts. The revenues produced by EMW's generation** covers the fuel cost but does not offset much of its load costs. EMW relies on the market to provide the electricity needed by its customers.[270]

224. In the simplest terms, capacity is the maximum output an electricity generator can physically produce, measured in megawatts. Energy is the amount of electricity a generator produces over a defined period of time. For example, a generator with a capacity of 100 MW that runs at full capacity for 10 hours generates 1,000 MWh (100 MW * 10 hours = 1,000 MWh) of energy.[271]

[268] Ex. 302, Mantle Rebuttal p.4.
[269] Ex. 302, Mantle Rebuttal p. 10.
[270] Ex. 302, Mantle Rebuttal, p. 5.
[271] Ex. 302, Mantle Rebuttal, pp. 9-10.

225. During Winter Storm Uri, EMW incurred more than $315 million in fuel and purchased power expenses. In File No. EF-2022-0155, EMW requested to recover more than $300 million of those costs from its customer through securitization.[272]

226. **The Commission's approach to IRPs involves the comparison of a variety** of resource plans (including different combinations of retirements and demand-side/supply-side additions) to assess which is the lowest cost, and allows for the assessment of the value of incremental changes to the resource plan. The IRP process and the capacity expansion model have the same goal.[273]

227. When determining the acquisition, continuation, or retirement of any resource, the availability of fuel and the dispatchability of the resource, along with meeting environmental regulations needs to be considered. No one type of resource on its own can meet all of the requirements of a prudent resource plan; however, a diverse portfolio of resources will.[274]

228. **Sierra Club's testimony did not mention generation types or discuss any** base load alternatives in its discussion of the retirement of current base load units.[275] **Sierra Club's analysis** did **not account for Evergy's need to have sufficient** capacity **and** meet reserve margin requirements.[276]

229. Base load generating units/plants are electric power sources that operate continuously to meet minimum levels of power demand on a 24/7 basis. Base load plants are usually large scale and are key components of an efficient and reliable electric grid.

[272] Ex. 302, Mantle, Rebuttal, p. 7, 17.
[273] Ex. 56, Messamore Rebuttal, p. 13.
[274] Ex. 302, Mantle Rebuttal, p. 14.
[275] Ex. 241, Hull Rebuttal, p. 6.
[276] Ex. 56, Messamore Rebuttal, pp. 11-12.

Base load plants are not designed to respond to peak demands or emergencies. Examples of base load units include coal and nuclear power plants.[277]

230. Intermediate power plants/units are used during the transition between base load and peak load demand. These plants are not as difficult to ramp up as base load plants or as expensive to operate as peak load plants. Wind and solar and some natural gas power plants fall in the intermediate category. Because wind and solar resources are intermittent by nature, and the electricity they generate fluctuates with the weather and the time of day, they cannot be depended on to meet peak demand or to provide energy on a consistent basis for base load purposes.[278]

231. A peaking power plant (commonly **referred to as a "Peaker plant") is one** that can switch on when additional power is needed, which will come online without much delay, and will start generating power on a moments' notice. Once a peak has passed, they are returned to standby mode for future peaks. Peaker plants are often used much less frequently over the course of a year than base and intermediate plants.[279]

232. A dispatchable resource provides electricity when the electricity is needed. Fossil fuel units are units that can be relied on to generate electricity when needed, *i.e.* dispatched, when fuel is available. When it is not needed to generate electricity, the plant does not generate. Renewable generation is not completely dispatchable.[280]

233. A good resource portfolio is one that contains diverse types of generation resources, each with its own strengths and weaknesses that are chosen to meet the

[277] Ex. 241, Hull Rebuttal, p. 4.
[278] Ex. 241, Hull Rebuttal, pp. 4-5.
[279] Ex. 241, Hull Rebuttal, p. 5.
[280] Ex. 302, Mantle Rebuttal, p. 13.

unique load demands of the utility's customers in all hours of the year while also minimizing the risk of high utility bills and loss of service.[281]

234. OPC disagreed with Sierra Club's recommendation to begin a process of retiring Evergy's coal plants.[282]

235. Sierra Club recommended a disallowance for EMM pertaining to capital costs and O&M for La Cygne Units 1 and 2 and Iatan 1 on the basis that EMM has not demonstrated the prudence of continuing to operate the plant relative to retirement and replacement with alternatives.[283]

236. Sierra Club recommended a disallowance for EMW pertaining to capital costs and O&M for Jeffrey Units 1-3 and its share of Iatan Unit 1 on the basis that EMW has not demonstrated the prudence of continuing to operate the plant as compared to retirement and replacement with alternatives.[284]

237. La Cygne is a two-unit, coal-fired power plant near La Cygne, Kansas. Unit 1 is 873 megawatts (MW), and Unit 2 is 685 MW, for a combined nameplate capacity of 1,558 MW. Unit 1 came online in 1973, and Unit 2 came online in 1977. EMM owns 50% of both units, and Evergy Kansas owns the other 50%. In the preferred plan of EMM's 2021 IRP, Unit 1 is set to retire in 2032, and Unit 2 is set to retire in 2039.[285]

238. Iatan is a two-unit, coal-fired plant near Weston, MO. Unit 1 is 726 MW and Unit 2 is 999 MW, for a combined nameplate capacity of 1,725 MW. Unit 1 came online in 1980, Unit 2 came online in 2010. EMM owns 61% of the plant and EMW owns 18%.

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[281] Ex. 302, Mantle Rebuttal, p. 14.
[282] Tr. Vol. 8, p. 272.
[283] Ex. 450, Glick Direct, p. 4; and Ex. 451, Glick Direct, p. 4 (Confidential version).
[284] Ex. 450, Glick Direct, p. 5; and Ex. 451, Glick Direct, p. 5 (Confidential version).
[285] Ex. 450, Glick Direct, p. 8.

The remainder is owned by non-affiliated entities. In the preferred plan of Evergy MO's 2021 IRP, Iatan Unit 1 is slated to retire in 2039 and Iatan Unit 2 is slated to retire in 2070.[286]

239. Jeffrey is a three-unit, coal-fired plant located in Emmet Township in Pottawatomie County, Kansas. Each of the three units has a nameplate capacity of 740 MW, for a total capacity of 2,220 MW. EMW owns 8% (175 MW) of the Jeffrey plant, and Evergy Kansas owns the other 92%. Unit 1 came online in 1978, Unit 2 in 1980, and Unit 3 in 1983. Jeffrey Units 1 and 2 are set to retire in 2039, and Unit 3 is set to retire in 2030.[287]

240. Generally, Sierra Club's concern was that continuing operations of coal plants could lead to large capital expenditures caused by future environmental regulations, and that such investment could then influence the continued use of the plant.[288]

241. Sierra Club asserted that the continued operation of all but two of Evergy's coal plants is potentially imprudent and thus all O&M and capital costs incurred at those facilities during the test year should be disallowed because of its dissatisfaction with Evergy's IRP process.[289]

242. EMW, as an 8% minority owner in the Jeffrey Energy Center, would not control a retirement decision.[290]

[286] Ex. 450, Glick Direct, p. 7.
[287] Ex. 450, Glick Direct, p. 7.
[288] Ex. 450, Glick Direct, p. 13.
[289] Ex. 56, Messamore Rebuttal, p. 13.
[290] Ex. 56, Messamore Rebuttal, p. 8.

243. Sierra Club calculated that each of the plants incurred costs in excess of the value of its energy and capacity over the past five years, with the exception of 2021 (referring to Winter Storm Uri[291]).[292] **However, Sierra Club's calculation did not reflect how** expenses are passed on to ratepayers.[293]

244. Sierra Club concluded from its analyses that the historical net revenues for the period 2017 to 2020 were significantly higher when the full capital expense amount was allocated to the year it was incurred when compared to when the capital expenses were amortized.[294]

245. **Utilities typically amortize capital expenditures (based on the utility's cost of** capital) and spread the costs out over the remaining economic life of the plant.[295]

246. Evergy argued that **Sierra Club's analyses simply compare costs to market** values of energy, ancillary services, and capacity, and assert that if costs are greater than total revenues, the continued operation of the plant must be imprudent. This type of analysis does not consider that Evergy needs to have sufficient economic capacity to serve customers and meet reserve margin requirements. [296]

247. **Sierra Club's claim that almost 1,700 MW of capacity** (over 4,300 MW if the capacity of those units which EMW and EMM do not own is included) should be retired on the basis of costs exceeding revenues and not including any assessment of costs for replacement capacity is not prudent.[297]

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[291] Ex. 450, Glick Direct, pp. 23-24; and Ex. 451, Glick Direct, pp. 23-24 (Confidential version).
[292] Ex. 450, Glick Direct, pp. 21-22; and Ex. 451, Glick Direct, pp. 21-22 (Confidential version).
[293] Ex. 450, Glick Direct, pp. 32-33; and Ex. 451, Glick Direct, pp. 32-33 (Confidential version).
[294] Ex. 450, Glick Direct, p. 27 and 35; and Ex. 451, Glick Direct p. 27 and 35 (Confidential version).
[295] Ex. 450, Glick Direct, p. 33
[296] Ex. 56, Messamore, pp. 11-12.
[297] Ex. 56, Messamore, pp. 11-12.

248. A prudent electric utility analysis of retiring a generating plant should include an assessment of the cost to replace its capacity.[298]

Conclusions of Law:

No additional Conclusions of Law are necessary.

Issues Presented by the Parties:

Resource Planning

A. Has EMW been imprudent in its resource planning process?

1. If yes, how should EMW's fuel and purchased power costs be determined?
2. If yes, how should EMW's FAC base factor be calculated?
3. If yes, how should EMW's accumulation period actual costs be adjusted for its FAC?

B. Should the Commission require Evergy to conduct a full retirement study of its coal fleet using optimized capacity expansion software, which identifies the optimal retirement date for each of its coal-fired units?

Rate Base

Has Evergy met its burden of proof to permit recovery from ratepayers of capital and O&M costs proposed in the test year for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2?

Decision:

Resource Planning

Sierra Club has suggested a finding of imprudence regarding the resource planning involved with coal-fired generating plant. Sierra Club proposes that coal plants should be retired more quickly than already planned. Staff, OPC and Evergy all disagree with Sierra Club's position for different reasons. Sierra Club's analysis over-simplifies the analysis required to make these decisions. Sierra Club's proposal does not account for the replacement of the capacity of the retired power plant; type of replacement capacity

[298] Tr. Vol. 8, p. 272.

(baseload/dispatchable capacity) and its implications; and stranded costs of the retired plant. The standard to begin a prudency analysis is the raising of a serious doubt. The Commission finds that Sierra Club has not raised a serious doubt about **Evergy's resource** planning. **The Commission does not find the reason for Sierra Club's request for a full retirement study of Evergy's coal units** using optimized capacity expansion software persuasive, especially given that Evergy is already utilizing this tool.

<u>Rate Base</u>

Sierra Club's recommendation to disallow the costs of certain coal plants has overlooked two key factors in the retirement of utility generation. Sierra Club's analysis did not adequately address undepreciated investment and also fails to address the fact that **these coal plants are not solely Evergy's to control and determine a retirement date.** The standard to pursue a finding of imprudence is to raise a serious doubt about the practice at issue. The Commission does not find that Sierra Club has raised a serious **doubt regarding the prudence of Evergy's** resource planning and therefore its spending on capital and O&M costs for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2. The Commission finds that Evergy has met its burden of proof to permit recovery of capital and O&M costs proposed in the test year for Iatan Unit 1, Jeffrey Unites 1-3, and La Cygne Units 1 and 2.

<u>STREETLIGHTING (EMW ONLY)</u>

Findings of Fact:

249. The City of St. Joseph (St. Joseph) recommends revisions to Tariff Sheet No. 150 to permit a municipality to build streetlights as part of a public works project, or

to have them built by a contractor as part of a city-approved development, and deem ownership of the streetlights to be in Evergy.[299]

250. The proposal of transferring ownership of streetlighting was offered by St. Joseph Light and Power Company (SJLP) as part of its municipal street lighting tariff.[300]

251. Historically, St. Joseph was able to require a developer build the streetlights and then have the utility take ownership of the streetlights (Developer Installed Option). **Evergy's current practice charges the streetlighting fees directly to St. Joseph.**[301]

252. St. Joseph was the only EMW customer to have the Developer Installed Option to the municipal streetlighting tariff.[302]

253. **To Evergy's best knowledge, the practice of allowing developer installed** streetlighting in St. Joseph began through a memorandum of understanding that followed **SJLP's purchase of the St. Joseph streetlighting system in the 1980s** or early 1990s.[303]

254. Subsequently, SJLP and another electric utility, Missouri Public Service Company, merged under Aquila and then KCP&L Greater Missouri Operations Company, and in 2016 consolidated the **various companies'** streetlighting tariffs in File No. ER-2016-0156.[304]

255. The City of St. Joseph was a party to File No. ER-2016-0156.[305]

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[299] Ex. 51, Lutz Rebuttal, p. 9.
[300] Ex. 51, Lutz Rebuttal, p. 10.
[299] Ex. 307, Marke Rebuttal, p. 23.
[302] Ex. 51, Lutz Rebuttal, p. 12.
[303] Ex. 51, Lutz Rebuttal, p. 10.
[304] Ex. 51, Lutz Rebuttal, p. 10.
[305] Order Granting Intervention, issued March 21, 2016, File No. ER-2016-0156.

256. Provisions for the Developer Installed Option were not included in the 2016 consolidated streetlighting tariffs as the consolidation sought to end lighting options that were not suited for universal application across the service area.[306]

257. In a limited deployment, such as the city limits of St. Joseph with approximately 45 square miles, the Developer Installed Option was practical in that utility companies could travel to inspect a streetlight quickly and utility relationships with the small number of developers allowed some familiarity and interaction with the developers' streetlight installers to assist quality control.[307]

258. Beginning in 2017, Evergy began a systematic conversion of its municipal street lighting to light emitting diode (LED) technology.[308]

259. In spring of 2018, St. Joseph lifted a 12-year suspension on city-initiated streetlight expansion.[309]

260. Also in spring of 2018, EMW completed a conversion of all non-decorative streetlighting fixtures to LED technology.[310]

261. St Joseph has approximately 6,500 LED lighting type streetlights, plus a few older light types such as high pressure sodium or mercury vapor.[311]

262. As a rule of thumb, and subject to change due to location and other conditions, it costs Evergy roughly $3,800 to purchase and install a metal street light pole.[312]

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306 Ex. 51, Lutz Rebuttal, pp. 10-11.
307 Ex. 52, Lutz Surrebuttal, p. 33.
308 Ex. 117, Lutz Direct, p. 52.
309 Ex. 51, Lutz Rebuttal, p. 11.
310 Ex. 51, Lutz Rebuttal, p. 11.
311 Tr. Vol. pp. 881-882.
312 Tr. Vol. 12, p. 872; and pp. 880-881.

263. The LED conversion and the lifting of the 12-year suspension brought to attention **the change in EMW's streetlighting tariff, which resulted in multiple meetings** between Evergy and St. Joseph, resulting in a letter sent to St. Joseph in December of 2018.[313]

264. In 2019 St. Joseph attempted to invoke the terms of the Developer Installed Option contained in the pre-2016 streetlighting tariff, which had provided for transferring ownership of streetlighting to Evergy, which resulted in additional meetings and a letter sent to St. Joseph in April 2020.[314]

265. The letter sent in April 2020 presented two alternatives to St. Joseph: 1) let Evergy build all the new streetlights; or 2) St. Joseph build the new streetlights itself and also own and maintain them.[315]

266. A maintenance only rate in Tariff Sheet No. 151 attempts to remove the equipment ownership aspects and provide only maintenance and energy cost elements.[316]

267. Tariff Sheet No. 150.1 describes the additional optional charges applicable only to streetlights owned by EMW to recover the costs associated with the installation of the elements listed in 4.1 to 4.5 of the tariff sheet.[317]

268. City owned streetlights would not be subject to the charges in Tariff Sheet No. 150.[318]

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[313] Ex. 51, Lutz Rebuttal, p. 11.
[314] Ex. 51, Lutz Rebuttal, pp. 11-12.
[315] Ex. 850, Carter Direct, p. 3; Ex. 854 is a copy of the April 2020 letter.
[316] Tr. Vol. 12, p. 884.
[317] Tr. Vol. 12, pp. 886-887.
[318] Tr. Vol. 12, pp. 886-887.

269. St. Joseph can install and own streetlights, but that would require adding liability insurance and maintenance costs to the city budget.[319]

270. Breakaway bases are special bases for streetlight poles designed to fragment if hit by a vehicle. It is used as the base for a metal light pole.[320]

271. Undergrounding refers to how the electricity is extended to the light pole, by installing the electric distribution line underground rather than by overhead wire. Depending on soil conditions around the new streetlight, rock may need to be removed or other specialized trenching or boring be employed to extend electricity to the streetlight pole underground.[321]

272. The purpose of charges for underground conductors and breakaway bases is to cover the ongoing maintenance of these items; the costs are not accounted for elsewhere in the streetlighting tariff.[322]

273. Where the streetlighting tariff refers to charges added for new, basic installations, it does not mean a new streetlight, rather it establishes the conditions of new installation versus a retrofit. The designation of new does not limit EMW's charges to installation only, it is an ongoing monthly charge for continued maintenance.[323]

274. In order to re-adopt the Developer Installed Option, EMW would need to be prepared to support all municipalities wishing to utilize the option.[324]

275. St. Joseph testified that the ability to require developers to install streetlighting at the developer's cost is a policy decision that should be left to local

[319] Ex. 850, Carter Direct, pp. 3-4.
[320] Ex. 851, Carter Surrebuttal, pp. 6-7.
[321] Ex. 851, Carter Surrebuttal, p. 7.
[322] Ex. 51, Lutz Rebuttal, p. 12.
[323] Tr. Vol. 12, pp. 871-872.
[324] Ex. 51, Lutz Rebuttal, p. 12.

municipalities, but that it would be content with some other designated limitation to reduce the availability of the tariff to just itself or a small group.[325]

276. St. Joseph argues that the capital costs of streetlights should be borne by the developers who are causing the expansion, and not the city operating budget.[326]

277. St. Joseph distinguishes the capital costs of the city versus the operating costs.[327] It is this change in the city's budget – paying for the streetlights from its capital costs to its operating costs that is the cause of St. Joseph's concern.[328]

278. St. Joseph argues that the change to the streetlighting tariff removed the city's ability to allocate capital expense to developers, and instead burdened the city with significant infrastructure cost.[329]

279. St. Joseph argued that it is unfair for it to have to pay ongoing monthly charges related to undergrounding, breakaway bases, rock removal, or other specialized trenching/boring.[330]

280. Sixty-one streetlights have been identified as being transferred from St. Joseph to EMW in 2017.[331]

281. Of the 61 identified streetlights, 31 have breakaway bases.[332]

282. All 61 identified streetlights require undergrounding.[333]

283. The 61 streetlights are in EMW's rate base valued at zero dollars.[334]

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[325] Ex. 851, Carter Surrebuttal, pp. 3-4.
[326] Ex. 850, Carter Direct, p. 4.
[327] Ex. 851, Carter Surrebuttal, p. 4.
[328] Ex. 851, Carter Surrebuttal, pp. 4-5.
[329] Ex. 851, Carter Surrebuttal, p. 2.
[330] Ex. 850, Carter Direct, pp. 6-7.
[331] Ex. 850, Carter Direct, p. 7.
[332] Tr. Vol. 12, p. 867.
[333] Tr. Vol. 12, p. 867.
[334] Tr. Vol. 12, p. 873.

Conclusions of Law:

DD. Streetlighting Tariff Sheet No. 151 contains no restriction on third parties' ability to install streetlights.

EE. Section 393.130.3 prohibits an electrical corporation from granting undue or unreasonable preference to select ratepayers and locales.

Issues Presented by the Parties:

> **A. Should language be added to EMW's Municipal Street Lighting Service** Tariff providing that streetlights installed by a city contractor or a city-approved developer shall be deemed to be owned by Evergy, after inspection and approval by the Company, and shall not be subject to additional installation or structure charges?
>
> **B. Should language be added to EMW's Municipal Street Lighting Service Tariff providing that no "Optional Equipment" charges in Section 4.0 or 5.0** of Municipal Street Lighting Service Tariff will be charged to streetlight facilities which are deemed to be owned by the Company and installed by a city or its contractor, or by a developer of a city-approved development?
>
> C. Should the Company be required to remove from its rate base streetlights that were installed by city contractors or city-approved developers?
>
> D. Should the Company be required not to charge the City of St. Joseph for **breakaway bases**, **undergrounding and other "Optional Equipment" charges** under Sections 4.0 and 5.0 of the tariff for streetlights that were installed by city contractors or city-approved developers?

Decision:

The Commission is sympathetic to the position of St. Joseph. It had a program whereby the city accumulated street lights, but did not have to pay to purchase and install them as they were paid for by the developer. Under the previous tariff of transferring ownership of streetlighting, the city streetlights also received ongoing maintenance at no cost to the city.

Such a program, however, is not suited for universal application across the EMW service area. The Developer Installed Option provisions of the streetlighting tariff began with a memorandum of understanding between EMW's predecessor and St. Joseph when St. Joseph Light and Power was acquired by Aquila. It is from this arrangement that the original tariff provisions were created. No other city ever participated in the Developer Installed Option.

When the streetlighting tariffs were consolidated in File No. ER-2016-0156, the Developer Installed Option was removed as it was not suited for universal application across the service territory. In arguing for the revival of Developer Installed Option, St. Joseph argued that it would accept verbiage which limited the program's availability within the service territory. In essence, St. Joseph requested that the Commission order EMW to offer the Developer Installed Option to everyone, or just to St. Joseph.

By statute, tariffs are required to be non-discriminatory. St. Joseph first requests that the Developer Installed Option would be available to everyone. This argument fails due to the cost and involvement of offering such a streetlight ownership transfer program across the service territory. EMW's response in sum is that transferring ownership and maintenance of approximately 6,500 streetlights in a city of 45 square miles is achievable, but only due to the relatively small area. If the Developer Installed Option would be reinstated and available to all customers; the costs, personnel needed, and lack of current compliance standards makes enactment of the tariff provisions unreasonable.

St. Joseph argued that the Developer Installed Option could be limited to certain city or county classifications, or geographic identifiers. St. Joseph did not offer any evidence that there was a difference in the provision of street lighting service for St. Joseph's streetlights or in the provision of service of cities of a certain size or within a county of a certain designation as compared to other customers taking service under the streetlighting tariff such that the preference could be justified. The Developer Installed Option, as recommended by St. Joseph, is not appropriate due to the high cost associated with offering it **across EMW's service area.** Additionally, there is no evidence to support a finding that limiting the availability of the streetlight transfer of ownership provisions to only St. Joseph or other similarly situated cities would be justified.

St. Joseph also recommended that the streetlights it has already transferred **ownership of be removed from EMW's rate base. EMW credibly testified that the** transferred streetlights were in rate base for the purpose of tracking, but that all transferred streetlights were entered at a valuation of zero dollars. The Commission does **not find St. Joseph's recommendation reasonable as the tracking is useful, and EMW is** not earning a return on the transferred streetlights.

Lastly, St. Joseph recommended that it be exempted from having to pay for the continuing maintenance of the streetlights it transferred, specifically mentioning the undergrounding and breakaway bases. This recommendation fails for the reason that the charges it opposes are tied to the ongoing maintenance of the streetlights. Even though transferred by St. Joseph to EMW, St. Joseph must still pay the monthly charges for EMW-owned streetlights under the terms of the tariff. Those monthly charges include energy and, pertinent to this subissue, maintenance. If St. Joseph desires to pay EMW only for energy and not for maintenance, then Tariff Sheet No. 151 details the energy charges for streetlights not owned or maintained by EMW. However, streetlights not owned or maintained by Evergy will be the responsibility of the streetlight owners, which is the situation that St. Joseph finds objectionable. The Commission does not find reasonable the recommendation of St. Joseph to be exempt from certain streetlighting charges addressing ongoing maintenance due to a prior transfer of ownership of the streetlights.

CENTRAL NEBRASKA PUBLIC POWER AND IRRIGATION DISTRICT HYDRO PURCHASED POWER AGREEMENT

Findings of Fact:

284. EMM entered into a hydro purchased power agreement with Central Nebraska Public Power and Irrigation District ("the Hydro PPA") to meet the Kansas Renewable Energy Standard.[335]

285. The Company's response to a discovery request in File No. ER-2018-0145 provides a power point presentation that provides information related to its justification for entering into the Hydro PPA contract.[336]

286. The Hydro PPA contract is effective from January 1, 2014, through December 31, 2023.[337]

287. The Hydro PPA contract has been serving customers in both Missouri and Kansas.[338]

288. Since the effective dates of rates from File No. ER-2018-0145, EMW alleges that the Hydro PPA has been included in base energy rates but has been excluded from the ongoing FAC Fuel Adjustment Rate ("FAR") filings.[339]

289. The Hydro PPA cannot be used to meet the Missouri Renewable Energy Standard because the three plants are accredited at 18 MW each and the Missouri statute

[335] Ex. 302, Mantle Rebuttal, p. 25; Tr. Vol 13, pp. 945-946.
[336] Ex. 336, Surrebuttal Testimony of Lena Mantle in ER-2018-0145, Schedule LMM-S-4C.
[337] Tr. Vol. 13, p. 951.
[338] Tr. Vol. 13, pp. 954-955.
[339] Ex. 66, Nunn Surrebuttal, p. 7.

requires plants to be rated at 10 MW or less to qualify for inclusion in meeting the Missouri Renewable Energy Standard.[340]

290. **The Hydro PPA's capacity is not needed** for EMM to meet resource adequacy requirements of SPP.[341]

291. **The Hydro PPA's energy is not needed to meet customer load in** Missouri.[342]

292. Staff argues that there is no benefit to Missouri customers just by being served; if the costs are exceeding the revenues, there is no benefit.[343]

293. OPC testified that there are no benefits to Missouri customers based on the Hydro PPA.[344]

294. Staff argues that there should be no recovery for the energy used to serve Missouri customers, and that Evergy can choose to serve Missouri customers without the Hydro PPA.[345]

295. **Staff witness Shawn Lange, P.E., modeled EMM's generation and load** requirements, and determined that, **as modeled by Staff**, **EMM's generation exceeds its** total load from Kansas and Missouri by approximately 6 million MWh annually.[346]

296. The Hydro PPA was modeled by Staff at providing 300,000 MWh annually.[347]

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[340] Ex. 303, Mantle Surrebuttal, p. 6; *see also* Tr. Vol. 13, p. 986, stating the generators are noncompliant with the Missouri limit.
[341] Ex. 303, Mantle Surrebuttal, p. 6.
[342] Tr. Vol. 13, p. 961, and pp. 986-987.
[343] Tr. Vol. 13, p. 960.
[344] Tr. Vol. 13, pp. 986-987.
[345] Tr. Vol. 13, p. 963.
[346] Tr. Vol. 13, pp. 974-976; Ex. 335C.
[347] Tr. Vol. 13, p. 977.

297. The modeled costs for the Hydro PPA were in excess of the revenues that were modeled.[348]

298. OPC testified to reviewing the test-year time period, and found that the costs of the Hydro PPA exceeded revenues for every month of the test-year period.[349]

299. There are instances where EMM would not be able to dispatch all 21 million MWh and would need to purchase power from SPP to meet its system load.[350]

300. EMM's generation is dispatched by the SPP.[351]

Conclusions of Law:

FF. The United States Supreme Court has stated:

> The filed rate doctrine also precludes a regulated utility from collecting any rates other than those properly filed with the appropriate regulatory agency. This aspect of the filed rate doctrine constitutes a rule against retroactive ratemaking or retroactive rate alteration. In its discussion of the doctrine, the [Court] explains that it explicitly prohibits an entity from "imposing a rate increase for gas already sold," and states, in a footnote, that an entity "may not impose a retroactive rate alteration and, in particular, may not order reparations.[352]

Issues Presented by the Parties:

How should the net cost of the Central Nebraska Public Power and Irrigation District ("CNPPID") hydro purchased power agreement ("PPA") be treated?

1. Should a normalized cost be included in the calculation of the fuel and purchased power costs of Evergy Metro's revenue requirement?

2. Should a normalized cost be included in the Evergy Metro fuel adjustment clause ("FAC") base factor calculation?

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[348] Tr. Vol. 13, p. 983.
[349] Tr. Vol. 13, pp. 987-988, and 990.
[350] Tr. Vol. 13, p. 981.
[351] Tr. Vol. 13, p. 982.
[352] *State ex rel. Associated Natural Gas Co. v. Public Service Comm'n*, 954 S.W.2d 520, 531 (Mo. App. W.D. 1997) (internal citations omitted).

3. Should the actual CNPPID hydro PPA costs be included in **Evergy Metro's actual accumulation period FAC costs?**[353]

Decision:

Evergy argues that the Hydro PPA serves Missouri customers and as such is used and useful. Although used, evidence shows it is not needed to meet Missouri customer load, its costs have exceeded revenues in every month of the current rate case test year, and thus, it is not useful to Missouri customers or economic.

Evergy also argues that the Hydro PPA was included in the base energy rate in the previous rate case and that the practice should be extended in this rate case. Underlying this argument are the terms of a settlement agreement from EMM's same previous rate case, File No. ER-2018-0145. The parties have disagreed about the inclusion, or exclusion, of the Hydro PPA in the settlement, and whether the settlement only dictated exclusion of the Hydro PPA from recovery under the FAC, or excluded the Hydro PPA from recovery in the base energy rate as well. The Commission does not reach a decision on what was or was not involved in that settlement, nor is it permitted to make adjustments even if the Hydro PPA was previously included in the base energy rate in error. **The Commission's decision is based on the fact that the Hydro PPA's usefulness** was not shown during the test-year. Moreover, the initial ten-year term of the Hydro PPA contract ends in December 31, 2023. The Hydro PPA does not provide benefits to Missouri customers and therefore will be excluded from recovery from Missouri customers.

[353] Questions edited due to overlapping issues.

Conclusion:

The Commission, having considered the competent and substantial evidence upon the whole record, makes the above findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making these findings. Any failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission did not consider relevant evidence, but indicates rather that omitted material is not dispositive of this decision.

Except as otherwise set out in the body of this order, the Commission finds that EMM and EMW have met their burden of proof to show that an increased rate for each is just and reasonable. Thus, the Commission concludes, based upon its review of the whole record that rates approved as a result of this order support the provision of safe and adequate service. The revenue requirement authorized by the Commission is no more than what is sufficient to keep **EMM's and EMW's** utility plant in proper repair for effective public service and provide to Evergy**'s** investors an opportunity to earn a reasonable return upon funds invested.

By statute, orders of the Commission become effective in thirty days, unless the Commission establishes a different effective date.[354] To match the suspension date of the proposed tariffs, the Commission will make this order effective on December 6, 2022.

THE COMMISSION ORDERS THAT:

1. The tariff sheets submitted on January 7, 2022, by EMM, and assigned Tracking Nos. YE-2022-0200 and YE-2022-0201 are rejected.

[354] Section 386.490.2, RSMo.

2. EMM is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order and the *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022.

3. The tariff sheets submitted on January 7, 2022, by EMW, and assigned Tracking No. YE-2022-0202 are rejected.

4. EMW is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order and the *Order Approving Four Partial Stipulations and Agreements*, issued September 22, 2022.

5. The retirement of Sibley was prudent.

6. All determinations regarding the Sibley AAO are as set forth in the body of this order.

7. AMI-SD meters installed for the three reasons of (1) exchange of AMI meter for AMI-SD meter; (2) exchange of AMI meter for an AMI-SD meter due to customer arrears; and (3) unknown reasons are disallowed from recovery.

8. Fifty percent of the cost of the consultant fees associated with Subscription Pricing are disallowed from recovery.

9. Residential rates for Evergy are authorized as follows:

a. Evergy's 2-period TOU proposed rate will be the default rate beginning six months after Evergy's tariffs in compliance with this order become effective;

b. Staff's proposed low-differential rate is approved as an opt-in rate, without a lead-in time;

c. Evergy's additional TOU rate proposals are authorized on an opt-in basis, without a lead-in time.

Evergy shall eliminate the identified residential rate codes and transition customers to the identified existing codes as discussed in the body of this order. Additionally, Evergy shall implement a program to engage and educate customers in the six-month lead-in time until its tariff provisions regarding the 2-period TOU rate as the default rate for residential customers becomes effective.

10. Non-residential rates for Evergy are authorized in the form of Evergy's proposed Time-Related Pricing rate on an opt-in bases, seasonal alignment matching EMM to EMW, and code consolidation and elimination of select end use rates.

11. Evergy shall host a meeting with interested stakeholders related to its rate modernization plan within 180 days of the effective date of Evergy's tariffs filed in compliance with this order.

12. Sierra Club's allegation of imprudence regarding resource planning involving coal plants is denied for lack of raising a serious doubt as to the prudence of existing resource planning.

13. Sierra Club's allegation of imprudence regarding Evergy's test-year spending on capital and O&M costs for Iatan Unit 1, Jeffrey Units 1-3, and La Cygne Units 1 and 2 is denied for lack of raising a serious doubt as to the prudence of its test-year spending for the above listed coal-fired generation plants.

14. St. Joseph's request to add language to EMW's streetlight tariff related to the Developer Installed Option is denied.

15. St. Joseph's request that the streetlights it has already transferred ownership of be removed from EMW's rate base is denied.

16. **St. Joseph's request** that it be exempted from having to pay for the continuing maintenance of the streetlights it already transferred to EMW is denied.

17. The Hydro PPA is disallowed from recovery as it is not used and useful to Missouri customers.

18. This Report and Order will become effective on December 6, 2022.

BY THE COMMISSION

Morris L Woodruff

Morris L. Woodruff
Secretary

Silvey, Chm., Rupp, Coleman, and
Kolkmeyer CC., concur.
Holsman, C., dissents.

Hatcher, Senior Regulatory Law Judge

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 21st day of November, 2022.

Morris L Woodruff

Morris L. Woodruff
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

November 21, 2022

File/Case No. ER-2022-0129 and ER-2022-0130

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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Morris L Woodruff

Morris L. Woodruff
Secretary

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FILED
May 01, 2023
Data Center
Missouri Public
Service Commission

Exhibit No. 12

Ameren – Exhibit 12
Ann E. Bulkley
Direct Testimony
File No. ER-2022-0337

Exhibit No.:	
Issue(s):	Cost of Capital
Witness:	Ann E. Bulkley
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2022-0337
Date Testimony Prepared:	August 1, 2022

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

ANN E. BULKLEY

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2022

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DIRECT TESTIMONY

OF

ANN E. BULKLEY

FILE NO. ER-2022-0337

I. Introduction

Q: Please state your name, occupation and business address.

A: My name is Ann E. Bulkley. I am a Principal with The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q: On whose behalf are you submitting this Prepared Direct Testimony?

A: I am submitting this testimony on behalf of Ameren Missouri (the "Company"), a wholly-owned subsidiary of Ameren Corporation ("Ameren").

Q: Please describe your background and professional experience in the energy and utility industries.

A: I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional and educational background is presented in Schedule AEB-D1.

Q: What is the purpose of your Prepared Direct Testimony?

A: The purpose of my testimony is to present evidence and provide a recommendation regarding the appropriate return on equity ("ROE")[1] for Ameren Missouri to be used for ratemaking purposes. My analyses and recommendations are supported by the data presented in Schedule AEB-D2, Attachments 1 through 12, which were prepared by me or under my direction.[2]

Q: How is the remainder of your Prepared Direct Testimony organized?

A: The remainder of my testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions on the Company's cost of equity.
- Section V explains my selection of the proxy group of electric utilities.
- Section VI describes my analyses and the analytical basis for the recommendation of the appropriate ROE for the Company.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.

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1 Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "cost of equity."

2 My testimony and supporting analyses rely, in part, on information obtained through a subscription with S&P Capital IQ Pro, and consequently, that information has been designated as confidential in accordance with licensing requirements of the provider.

- Section VIII presents my conclusions and recommendations for the market cost of equity.

II. Summary Of Analyses And Conclusions

Q: What are the key factors considered in your analyses and upon which your recommended cost of equity for the Company is based?

A: In developing my recommended ROE for the Company, I considered the following:

- The United States Supreme Court decisions in *Hope* and *Bluefield*[3] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies, and the implications of those risks.

Q: How did you develop your recommended cost of equity for the Company?

A: I relied on the results of several analytical approaches to estimate the costs of equity for Ameren Missouri. To develop my ROE recommendation, I first developed a proxy

[3] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope"); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield").

group that consists of electric utility companies that face risks generally comparable to those faced by Ameren Missouri. To that electric company proxy group, I applied the Constant Growth Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Risk Premium approach. As discussed in more detail herein, it is appropriate to rely on multiple ROE methodologies because market conditions affect the assumptions used in each model differently. Therefore, the use of multiple ROE estimation models is beneficial to provide benchmarks and a range of results to consider.

My recommendations also consider company-specific business and financial risk factors to estimate the investor-required cost of equity for the Company. Although the companies in my proxy group are generally comparable to Ameren Missouri, each company is unique, with no two having exactly the same risk profiles. Accordingly, while I did not make any specific adjustments to my ROE estimates for any of these factors, I considered the Company's business and financial risk in the aggregate in comparison to that of the proxy group companies when determining where the Company's ROE falls within the reasonable range of analytical results to account for any residual differences in risk.

Q: What are the results of your ROE estimation models?

A: Figure 1 summarizes the range of results of my cost of equity analyses for the Company.

FIGURE 1: SUMMARY OF COST OF EQUITY ANALYTICAL RESULTS

	Constant Growth DCF		
	Minimum Growth Rate (Median)	Average Growth Rate (Median)	Maximum Growth Rate (Median)
30-Day Average	8.11%	9.34%	10.38%
90-Day Average	8.09%	9.37%	10.37%
180-Day Average	8.21%	9.41%	10.53%
Constant Growth Average	8.14%	9.37%	10.43%
	CAPM		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.65%	11.73%	11.73%
Bloomberg Beta	11.20%	11.30%	11.31%
Long-term Avg. Beta	10.47%	10.61%	10.62%
	ECAPM		
Value Line Beta	11.97%	12.03%	12.03%
Bloomberg Beta	11.64%	11.71%	11.72%
Long-term Avg. Beta	11.09%	11.19%	11.20%
	Bond Yield Plus Risk Premium		
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	10.03%	10.27%	10.29%

As shown in Figure 1, the range of results produced by the ROE estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies. As a result, my ROE recommendation considers the range of results of analyses, as well as the company-specific risk factors and current and prospective capital market conditions expected during the time when rates set in this case would be in effect.

Q: What is your recommended ROE for Ameren Missouri?

A: Based on the analytical results presented in Figure 1, the current and projected capital market conditions, and the level of regulatory, business, and financial risk faced by Ameren Missouri's electric operations relative to the proxy group, I conclude that a ROE in the range of 9.90 to 11.25 percent is reasonable. In addition, the required ROE is a forward-looking estimate of the return required to attract capital on reasonable terms. Therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (*e.g.*, projected growth rates in the DCF model and a forecasted risk-free rate and market risk premium in the three risk premium analyses). Considering these factors, I conclude that the Company's requested ROE in this proceeding of 10.20 percent is reasonable.

III. Regulatory Guidelines

Q: Please describe the guiding principles used in establishing the cost of capital for a regulated utility.

A: The United States Supreme Court's *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[4]

Q: Is fixing a fair rate of return just about protecting the utility's interests?

A: No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[5] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[6]

Q: Has the Missouri Public Service Commission ("Commission") provided similar guidance in establishing the appropriate return on common equity?

A: Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases and acknowledges that utility investors are entitled to a fair and reasonable return. This position was set forth by the Commission as follows:

> The standard for rates is "just and reasonable," a standard founded on constitutional provisions, as the United States Supreme Court has explained. But the Commission must also consider the customers. Balancing the interests of investor and consumer is not reducible to a single formula, and making pragmatic adjustments is part of the Commission's duty. Thus, the law requires a just and reasonable end, but does not specify a means. The Commission is charged

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4 *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

5 *Bluefield*, 262 U.S. 679, 67 L Ed 1176 (1923).

6 *Hope*, 320 U.S. 591, 603 (1944).

> approving rate schedules that are as "just and reasonable" to consumers as they are to the utility.[7]

Based on these standards, the authorized ROE should provide the Company with a fair and reasonable return and should provide access to capital on reasonable terms in a variety of market conditions.

Q: Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A: A return that is adequate to attract capital at reasonable terms will enable the Company to continue to provide safe, reliable electric service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable risk. If it is lower, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby impairing the Company's ability to attract capital at reasonable cost. To the extent the Company is provided a reasonable opportunity to earn a market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q: Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A: Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE authorized for a

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7 *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, File No. ER-2014-0370, Report and Order, September 15, 2015, at 11.

utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other electric utilities can inhibit the utility's ability to attract capital for investment in Missouri.

Q: Are the authorized ROE and capital structure important to credit rating agencies?

A: Yes. The credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. The credit rating agencies are particularly focused on these metrics and have instituted negative ratings actions in reaction to regulatory commission decisions authorizing a cost of equity that is deemed to increase risk by reducing future cash flow.

For example, most recently, changes made by the Arizona Corporation Commission ("ACC") to an Administrative Law Judge's recommended order in an Arizona Public Service Company ("APS") rate proceeding caused credit rating agencies to institute negative ratings actions. Specifically, the ACC reduced the authorized ROE for APS from the ALJ-recommended 10.00 percent to 8.70 percent. With this reduction by the ACC, Fitch downgraded the issuer default credit rating of APS from A to A-, and its parent, Pinnacle West Capital Corporation ("PNW") from A- to BBB+, citing heighted business risk.[8] Subsequently, Moody's Investors Service, Inc. ("Moody's") also downgraded APS from A2 to A3 and PNW from A3 to Baa1.[9] Moody's noted that the downgrade was a function of "the recent decline in Arizona regulatory environment following the conclusion of the utility's 2019 rate case as well as the organization's weakened credit metrics."[10]

Guggenheim Securities LLC, an equity analyst that follows PNW, informed its clients that:

> [T]he "Arizona Corporation Commission is now confirmed to be the single most value destructive regulatory environment in the country as far as investor-owned utilities are concerned."[11]

Similarly, S&P Global Market Intelligence's Regulatory Research Associates ("RRA") noted that this decision was "among the lowest ROEs RRA had encountered in its coverage of vertically integrated electric utilities in the past 30 years."[12]

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8 FitchRatings, "Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative," October 12, 2021.

9 Moody's Investors Service, Inc., "Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3," November 17, 2021.

10 *Id.*

11 S&P Global Market Intelligence, "Pinnacle West shares tumble after regulators slash returns in rate case," October 7, 2021.

12 S&P Global Market Intelligence, RRA Regulatory Focus, "Commission accords Arizona Public Service Company a well below average ROE," October 8, 2021.

Q: What are your conclusions regarding regulatory guidelines?

A: The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Doing so balances the long-term interests of the utility and its customers.

The financial community carefully monitors the current and expected financial condition of utility companies and the regulatory frameworks in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide the Company with a reasonable opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions; (2) sufficient to ensure good financial management and firm integrity; and (3) commensurate with returns on investments in enterprises with similar risk. Providing Ameren Missouri the opportunity to earn its market-based cost of equity supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

Q: Does the fact that the Company is owned by Ameren, a publicly-traded company, affect your analysis?

A: No, it does not. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for Ameren Missouri, not its publicly-traded parent, Ameren. It is appropriate to establish a return on equity and capital structure that provide Ameren Missouri the ability to attract capital on reasonable terms.

IV. Capital Market Conditions

Q: Why is it important to consider capital market conditions in the estimation of the investor-required return on equity?

A: The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the risk premium models. Therefore, results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. Because the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst must use current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, analysts and regulators have concluded that current market conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that test year. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q: What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A: The financial environment is substantially different than when the Commission set the Company's current authorized ROE, and the changes in the capital markets will have a direct and significant effect on the ROEs required by investors. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) currently high inflation continuing into 2022; (3) increasing interest rates, and (4) volatile market conditions. These factors affect the assumptions used in the ROE estimation models, and as a result, it is important that these changed conditions are recognized by the Commission in establishing the Company's cost of equity in this proceeding.

Q: What effect do current and prospective market conditions have on the cost of equity for the Company?

A: The combination of persistently high inflation, the Federal Reserve's changes in monetary policy, and the dramatic shifts in market conditions resulting from political influences all contribute to an expectation of increased market risk and an increase in the cost of the investor-required return on equity. Inflation is currently at its highest level seen in approximately 40 years. Interest rates, which have increased significantly from the pandemic-related lows of 2020, are expected to continue to increase in direct response to the Federal Reserve's use of monetary policy. As discussed later herein, since there is a strong correlation between interest rates and authorized utility ROEs, it is reasonable to expect that investors' cost of equity is increasing. Because the cost of equity in this proceeding is being estimated for the period that the Company's rates will be in effect, and because utility cost of equity is expected to increase over the near term for utilities, it is essential that these factors be considered in setting a forward-looking cost of equity. ROE estimates based in whole or in part on current market conditions will understate the ROE during the future period that the Company's rates will be in effect.

IV.A. The Effect of Monetary Policy on Market Dynamics

Q: What actions were taken by the Federal Reserve in response to the COVID-19 pandemic?

A: As a result of the COVID-19 pandemic, the Federal Reserve undertook expansive monetary and fiscal programs to mitigate the economic effects of the pandemic and to provide additional support for the economy to recover from the COVID-19 recession. The expansive monetary and fiscal policy programs resulted in a strong economic recovery in 2021 from the COVID-19 induced recessionary period in 2020. In fact, according to the Bureau of Economic Analysis, real GDP grew by 5.7 percent in 2021 driven primarily by a 7.9 percent increase in personal consumption expenditures.[13] Moreover, the unemployment rate decreased from a high of 14.7 percent in April 2020 to 3.9 percent as of December 2021.[14] In addition, the economic recovery has also included a substantial increase in inflation. The strong economic recovery along with the increase in inflation has resulted in the Federal Reserve normalizing monetary policy and removing the accommodative policy programs that it used to mitigate the effects of COVID-19.

Q: Please summarize the monetary policy actions taken by the Federal Reserve over the past six months.

A: In the past six months, the Federal Reserve has taken a number of steps and continued to accelerate the normalization of monetary policy in response to the significant increase in inflation that has occurred. As of the June 15, 2022 meeting, the Federal Reserve:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[15]

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[13] Bureau of Economic Analysis, News Release, February 24, 2022, at 8.

[14] Bureau of Labor Statistics. https://data.bls.gov/timeseries/LNS14000000

[15] Federal Reserve Bank of New York, https://www.newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.

- Increased the target federal funds rate to 0.25 – 0.50 percent at the March 16, 2022 meeting,[16] to 0.75 to 1.00 percent at the May 4, 2022 meeting,[17] and then to 1.50 percent to 1.75 percent at the June 15, 2022 meeting;[18]
- Forecasted a total of seven additional 25-basis-point rate increases in 2022 and two 25-basis-point rate increases in 2023, which resulted in a median forecast of the federal funds rate of 3.4 percent and 3.8 percent, respectively;[19] and
- Started reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022. Specifically, the Federal Reserve will reduce the size of its balance sheet by only reinvesting principal payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury securities, the cap will be set at $30 billion per month for the first three months and $60 billion per month after the first three months, while for mortgage-backed securities the cap will be set at $17.5 billion per month for the first three months and $35 billion per month after the first three months.[20]

IV.B. Inflationary Expectations in Current and Projected Market Conditions

Q: Has the increase in inflation been significant?

A: Yes. As shown in Figure 2, the year-over-year ("YOY") change in the Consumer Price Index ("CPI") published by the Bureau of Labor Statistics was 1.37 percent in

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[16] Federal Reserve, Press Release, March 16, 2022.

[17] Federal Reserve, Press Release, May 4, 2022.

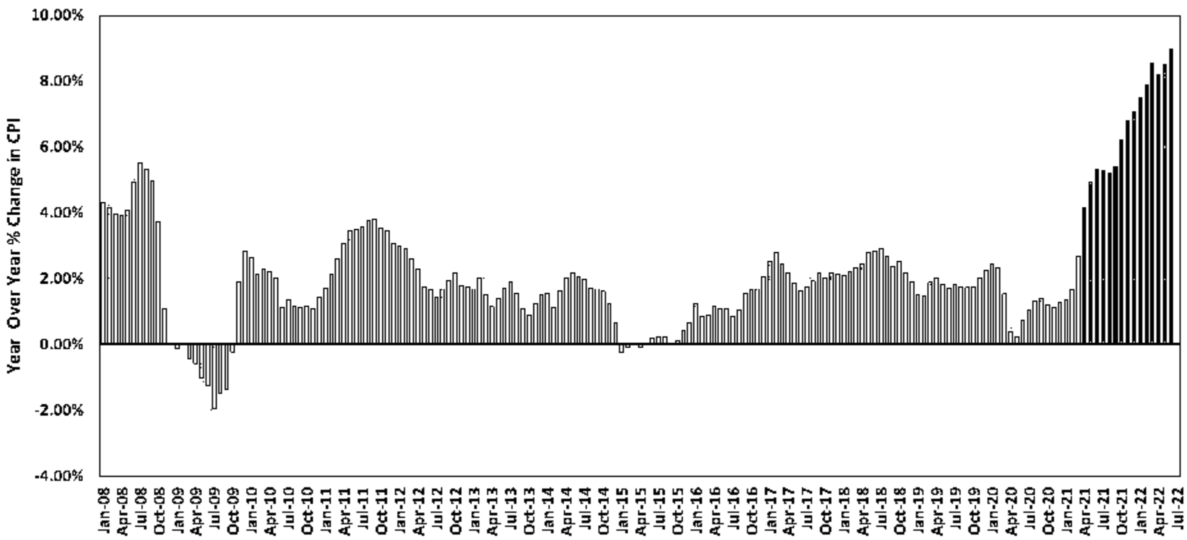
[18] Federal Reserve, Press Release, June 15, 2022.

[19] Federal Reserve, Summary of Economic Projections, June 15, 2022, at 2.

[20] Federal Reserve, Plans for Reducing the Size of the Federal Reserve's Balance Sheet, Press Release, May 4, 2022.

January 2021. However, since that time, and particularly since the start of 2022, inflation has increased steadily, reaching a high of 9.0 percent YOY change in June 2022, which is the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008.

FIGURE 2: YOY PERCENT CHANGE IN CONSUMER PRICE INDEX, JANUARY 2008 – JUNE 2022



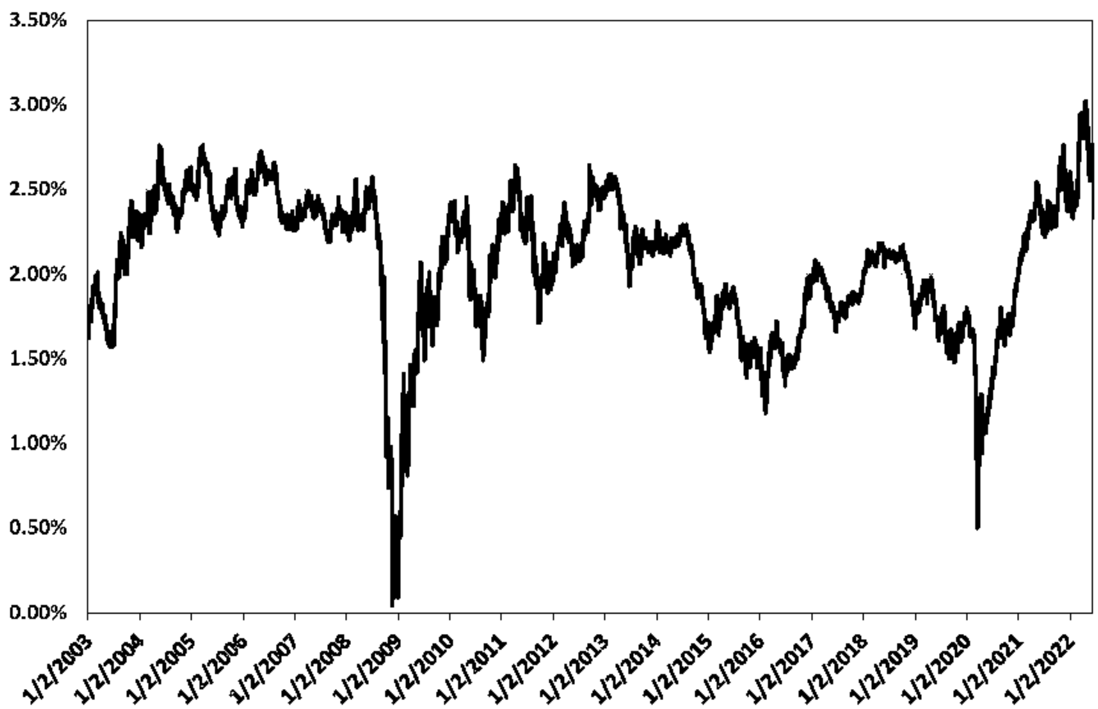
Q: Do investors expect inflation pressures to continue for a number of years?

A: Yes. One measure of investors' expectations regarding inflation is the breakeven inflation rate calculated as the spread between the yield on a Treasury bond and the yield on a Treasury Inflation-Protected bond, which would account for the effect of inflation. The maturity of the bond selected would then reflect investors' views of inflation during the holding period of the bond.

For example, the 10-year breakeven inflation rate is calculated as the spread between the 10-year Treasury bond yield and the 10-year Treasury Inflation-

Protected bond yield. As shown in Figure 3, the 10-year breakeven inflation rate is currently greater than any level seen since January 2003. Furthermore, the 30-day average of the 10-year breakeven inflation rate as of May 31, 2022 was 2.76 percent, indicating that investors expect inflation will remain well above the Federal Reserve's 2 percent target over the next 10 years.

FIGURE 3: 10-YEAR BREAKEVEN INFLATION RATE, JANAURY 2003 – JUNE 2022[21]



There are many factors as to why inflation is expected to remain elevated. For example, *Kiplinger* recently noted a few factors, including supply shortages due to COVID-19 and Russia's war in Ukraine, which led *Kiplinger* to forecast an inflation rate of 6.3 percent for 2022:

[21] Federal Reserve Bank of St. Louis, 10-Year Breakeven Inflation Rate [T10YIE].

> The inflation rate is expected to ease further over the rest of this year, but will likely end 2022 at a still-high rate of about 6.3%. In 2023 the rate should fall faster, down to 3.0% by the end of the year. The higher cost of housing will keep inflation rates elevated for some time to come. Gasoline prices and heating costs are likely to stay high for a good while because of the war in Ukraine, but they may plateau instead of climbing more. The price of cars and trucks will also stay at a high level until the semiconductor shortage ends sometime next year. Continued spot shortages of various items will drive their price up, adding to the overall inflation rate. The latest is a shortage of baby formula.[22]

IV.C. Effect of Inflation on Interest Rates and the Investor-Required Return

Q: What effect will inflation have on long-term interest rates?

A: Inflation and the Federal Reserve's normalization of monetary policy will likely result in increases in long-term interest rates. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond, and this risk increases the longer the duration of the bond. As a result, investors will require higher yields to compensate for the increased risk of inflation, which means interest rates in turn increase.

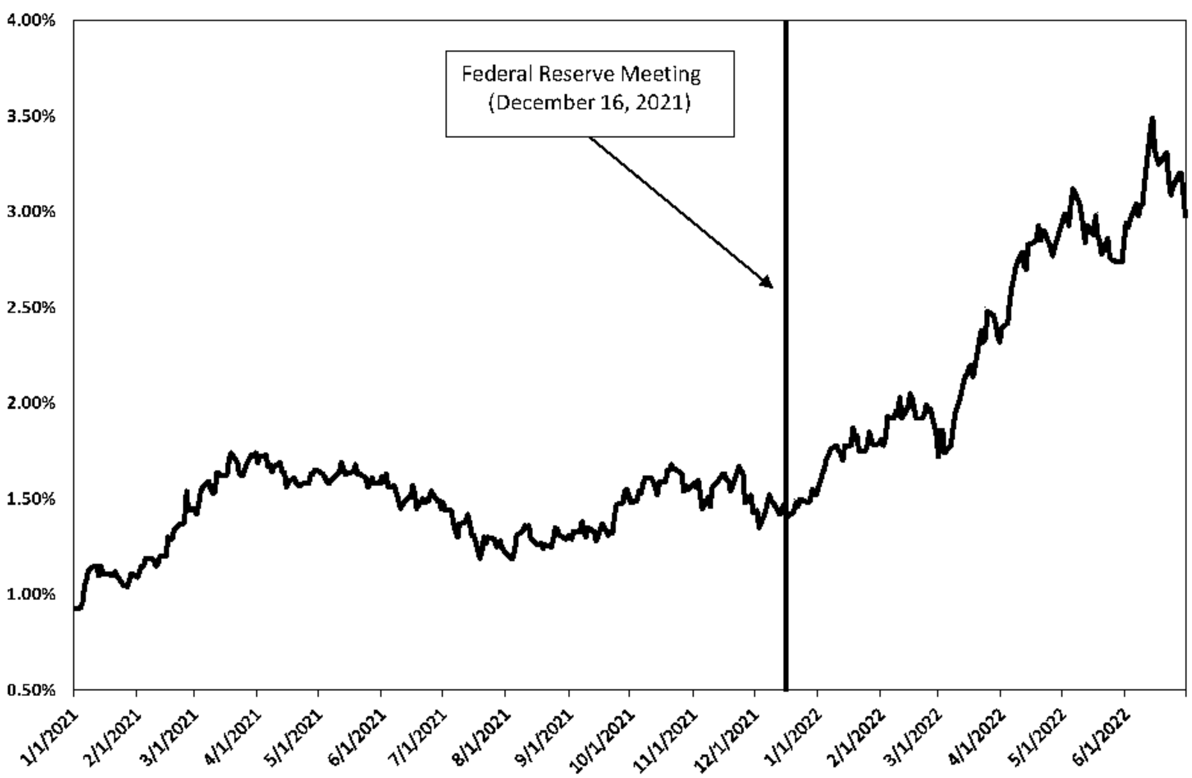
Q: Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A: Yes, they have. As shown in Figure 4, since the Federal Reserve's December 2021 meeting, as the process of normalizing monetary policy has accelerated to respond to inflation, the yield on the 10-year Treasury bond has increased over 150 basis

[22] Payne, David, "Inflation Will Ease, But Only Gradually This Year," *Kiplinger*, May 11, 2022.

points, from 1.47 percent on December 15, 2021 to 2.98 percent on June 30, 2022. The increase is due to the Federal Reserve's announcements at its December 2021, January 2022, March 2022 and May 2022 meetings, investors' expectations regarding the Federal Reserve's announcement at the June 2022 meeting, and the continued increased levels of inflation that are now expected to persist much longer than the Federal Reserve and investors had originally projected.

FIGURE 4: 10-YEAR TREASURY BOND YIELD, JANUARY 2021 – JUNE 2022[23]



Q: What have equity analysts said about long-term government bond yields?

A: Several equity analysts have noted that they expect economic conditions to continue to improve and thus the yields on long-term government bonds to continue to

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[23] S&P Capital IQ Pro.

increase through the end of 2022. As shown in Figure 5, equity analysts are projecting a range for the yield of the 10-year Treasury bond of between 3.15 percent and 4.00 percent through the end of 2022. In addition, it is important to note that the 10-year Treasury Bond was trading as high as 3.49 percent as of June 14, 2022.

FIGURE 5: EQUITY ANALYSTS FORECAST OF THE 10-YEAR TREASURY YIELD

	Actual
30-Day Average as of June 30, 2022	3.04%
	2022 Forecast
Advocate Capital Management [24]	4.00%
Goldman Sachs[25]	3.30%
Blue Chip Financial Forecasts (Consensus Estimate)[26]	3.40%
BMO Economics[27]	3.15%

Q: Have you considered any additional indicators that may imply long-term interest rates are expected to increase?

A: Yes, I have. I considered the net position of commercials (*i.e.*, banks) in U.S. Treasury Bond futures contracts as reported in the Commitment of Traders Report produced by the Commodity Futures Trading Commission. A net position is defined

[24] MarketWatch, "This bond expert who called the spike in U.S. yields forecasts the 10-year to reach 4%," May 7, 2022. https://www.marketwatch.com/story/this-bond-expert-who-called-the-spike-in-u-s-yields-forecasts-the-10-year-to-reach-4-11651843223.

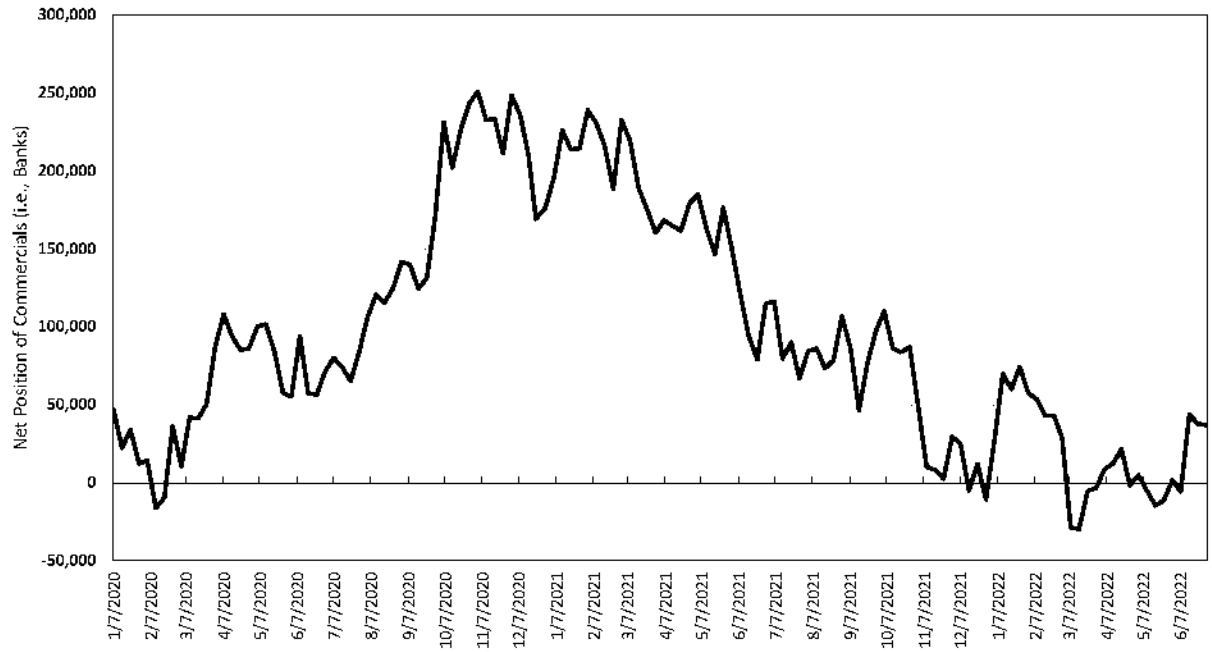
[25] Pollard, Amelia, "Goldman Lifts Yield Forecasts, Sees 10-Year Treasuries at 3.3%," Bloomberg.com, May 12, 2022.

[26] *Blue Chip Financial Forecasts*, Vol. 41, No. 7, July 1, 2022, at 2 (average of 3Q/2022 and 4Q/2022).

[27] BMO Economics, "Rates Scenario for May 11, 2022," May 11, 2022.

as the total number of long positions in a futures contract minus the total number of short positions in a futures contract. A long position means that an investor agrees to purchase an asset in the future at a specified price today and therefore profits if the price of the underlying asset increases. Conversely, a short position is when an investor agrees to sell an asset at a time in the future at a specified price today and profits if the price of the asset declines. Therefore, if banks are increasing the number of short positions and thus have a declining net position, the banks are assuming that the price of the asset will decline. As shown in Figure 6, the net position of banks in U.S. Treasury Bonds has been decreasing since the end of 2020. Therefore, banks are forecasting a decrease in the price of long-term government bonds and thus an increase in the yields (which are inversely related to the price) over the near-term.

FIGURE 6: COMMITMENT OF TRADERS REPORT – NET POSITION OF BANKS IN U.S. TREASURY BOND FUTURES CONTRACTS[28]



IV.D. Expected Performance of Utility Stocks and the Investor-Required ROE on Utility Investments

Q: Are utility share prices correlated to changes in the yields on long-term government bonds?

A: Yes, interest rates and utility share prices are inversely correlated which means, for example, that an increase in interest rates will result in a decline in the share prices of utilities. For example, Goldman Sachs and Deutsche Bank recently examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had

[28] Commitment of Traders Report, as of June 30, 2022; https://www.cftc.gov/MarketReports/CommitmentsofTraders/HistoricalCompressed/index.htm

one of the strongest negative relationships with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[29]

Q: Have electric utility stock prices recently increased?

A: Yes. Utility stock prices had trended down as interest rates moved higher; however, as a result of the political turmoil associated with the war in Ukraine, investors have recently returned to utility stocks as a safe haven seeking to lower risk, resulting in higher electric utility stock prices and thus lower dividend yields.

Q: How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A: Even with the recent increase in electric utility stock prices, equity analysts project that utilities are expected to continue to underperform the broader market as interest rates increase. For example, in its most recent Big Money poll, which closed in mid-April, *Barron's* surveyed 112 money managers regarding the outlook for the next twelve months, and the professional investors indicated that the utility sector as the least attractive of all industries for investment.[30] Additionally, Fidelity recently noted

[29] Lee, Justina, "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks," Bloomberg.com, March 11, 2021; www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.

[30] Jasinski, Nicholas, Bearish Now, Bullish Later: How Investors Are Sizing Up Stocks, Barron's, updated April 24, 2022.

that its underweight recommendation on the sector reflected a combination of "poor fundamentals and expensive valuations."[31]

Q: Have you reviewed any market indicators that may imply that utilities will underperform over the near-term?

A: Yes. As discussed, the utility sector is considered a "bond proxy" or a sector in which investors are attracted as a safe haven alternative to bonds, and utility stock prices are therefore inversely related to changes in interest rates. For example, the utility sector tends to perform well when interest rates are low since the dividend yields for utilities offer investors the prospect of higher returns when compared to the yields on long-term government bonds. Conversely, the utility sector underperforms as the yields on long-term government bonds increase and the spread between the dividend yields on utility stocks and the yields on long-term government bonds decreases. Therefore, I examined the yield spread between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through June 2022. I selected the dividend yield on the Utilities Select Sector SPDR Fund ("XLU")[32] as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury Bond as the estimate of the yield on long-term government bonds.

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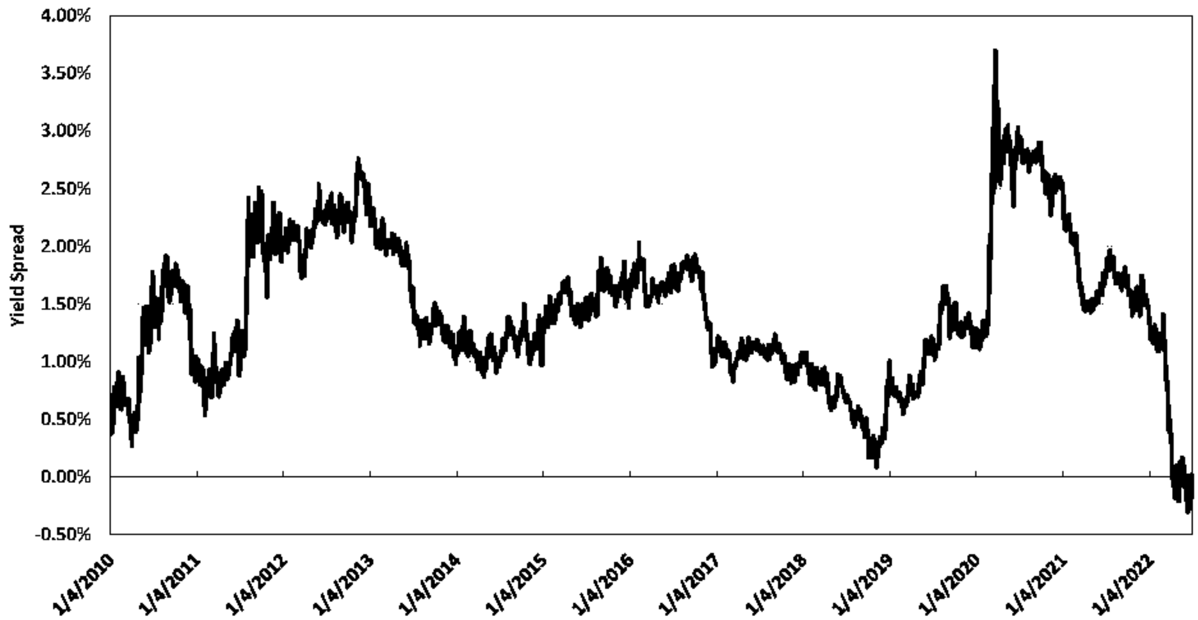
31 Chisolm, Denise, "Chisolm: Top sectors to watch in Q2," *Fidelity*, May 4, 2022.

32 The Utilities Select Sector Index includes companies from the following industries: electric utilities; water utilities; multi-utilities; independent power and renewable electricity producers; and gas utilities.

As shown in Figure 7, the yield spread first went negative in June 2022 indicating that yield on the 10-year Treasury Bond was greater than the dividend yield for the XLU, which has not occurred since 2010. The 30-day average yield spread as of the end of June was -0.07 percent, which is well below the long-term average since January 2010 of 1.44 percent. Given that the yield spread is currently negative and well below the long-term average, and interest rates are expected to continue to increase, it is reasonable to conclude that the utility sector will underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the low yields on long-term government bonds will begin to rotate back into government bonds as the yields on long-term government bonds continue to increase, thus resulting in a decrease in the share prices of utilities.

FIGURE 7: YIELD SPREAD BETWEEN THE DIVIDEND YIELD ON THE XLU AND THE YIELD ON THE 10-YEAR TREASURY BOND, JANUARY 2010 – JUNE 2022[33]



Q: What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A: As discussed, the Federal Reserve is aggressively normalizing monetary policy in response to inflation, which is expected to increase long-term government bond yields. As a result, an increase in interest rates will have an effect on the ROE estimation models used to establish the cost of equity for the Company in this proceeding that must be considered.

As explained further herein, the Constant Growth DCF model reflects the expected dividend yield plus an expected growth rate; however, historical utility stock prices are required to calculate a dividend yield. Therefore, if interest rates increase as

[33] S&P Capital IQ Pro; Bloomberg.

expected over the near-term during which the Company's rates will be in effect, then the share prices of utilities will decline, and dividend yields will increase. If dividend yields increase going forward, the ROE calculated by the model currently using historical utility stock prices and dividend yields will understate the ROE for the Company during the period in which its rates will be effective.

Because interest rates have increased substantially and are projected to be higher by the time the Company's rates are made effective, prospective market conditions warrant consideration of other ROE estimation models such as the CAPM and ECAPM, which may better reflect expected market conditions. The CAPM and ECAPM models rely on a risk-free rate, beta coefficient and market risk premium, and two of those inputs (*i.e.*, the risk-free rate and market risk premium) are forward-looking. However, since interest rates are increasing and expected to continue to increase over the near-term, relying on the historical average interest rates as the risk-free rate in the CAPM will also tend to understate the cost of equity.

Consequently, it is important to recognize that with the current and projected capital market conditions that the results of the ROE estimation models are lagging the investor-required returns over the period that the Company's rates will be in effect. Therefore, the current and expected market conditions support consideration of forward-looking estimates and a range of ROE results so that the Company's cost of equity is not understated during the period in which its rates will be in effect.

Q: Have state regulatory commissions considered market events and the utility's ability to attract capital in determining the equity return?

A: Yes. In a recent rate case for Consumers Energy Company, the Michigan Public Service Commission ("Michigan PSC") noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past. Specifically, the Michigan PSC stated that:

> [i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. *It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.*[34]

The Michigan PSC references "global events" and the overall effect the events could have on the ability of a utility to access capital. Consistent with the Michigan PSC's views, it is important to consider current market conditions and the impact of those

[34] Michigan Public Service Commission Order, Cause No. U-20697, Consumers Energy Company, December 17, 2020, at 165; emphasis added.

conditions on the access to and cost of capital, and to position utilities to be able to maintain access in rapidly changing market conditions.

IV.E. Conclusion Regarding Capital Market Conditions

Q: What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A: Over the near-term, investors expect long-term interest rates to increase in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, an increase in long-term government bond yields will likely result in a decline in utility share prices, which is the reason a number of equity analysts expect the utility sector to underperform over the near-term. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. This change in market conditions also supports the use of other ROE estimation models such as the CAPM and the ECAPM, which may better reflect expected market conditions.

V. Proxy Group Selection

Q: Have you developed a proxy group for estimating the ROE for the Company in this proceeding?

A: Yes. In this proceeding, I am estimating the cost of equity for the Company, which is a rate-regulated subsidiary of Ameren, and is not itself publicly-traded. Since the

ROE is a market-based concept, and the Company's operations do not make up the entirety of a publicly-traded entity, it is necessary to establish a group of companies that is both publicly-traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of the ROE estimation process. Even if Ameren Missouri were a publicly-traded entity, it is possible that transitory events could bias its respective market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and financial risk characteristics that are substantially comparable to Ameren Missouri, and, therefore, provide a reasonable basis for deriving the appropriate ROE.

Q: Please provide a brief profile of the Company.

A: Ameren Missouri (also known as Union Electric Company) is a wholly-owned subsidiary of Ameren Corporation. The Company is the largest electric utility in Missouri, providing regulated retail electric service to more than 1.2 million electric customers across a 24,000 square mile area in central and eastern Missouri, including the greater St. Louis metropolitan area.[35] As of December 31, 2021, the Company's net utility electric plant in Missouri was approximately $14.3 billion.[36]

[35] Ameren Corporation, Form 10-K, February 22, 2022, at 98.

[36] Union Electric Company d/b/a Ameren Missouri, FERC Form 1, April 14, 2022, at pp. 110-11.

Ameren Missouri's issuer/corporate credit rating is currently rated BBB+/Stable by Standard & Poor's ("S&P") and Baa1/Stable byMoody's.[37]

Q: How did you select the companies included in your proxy group?

A: I began with the group of 36 companies that Value Line Investment Survey ("Value Line") classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends because such companies can be analyzed using the Constant Growth DCF model;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- own generation assets included in rate base;
- have more than 40 percent of total energy sales provided by company-owned generation;
- derive more than 60 percent of total operating income from regulated operations;
- derive more than 80 percent of their total regulated operating income from regulated electric operations; and
- were not party to a merger or transformative transaction during the analytical period considered.

[37] Ameren Corporation, Form 10-K, February 22 ,2022, at 66; Moody's Investor Services, Inc., Credit Opinion, Union Electric Company, September 13, 2021.

Q: Did you exclude any other companies from the proxy group?

A: Yes. I also excluded Pinnacle West Capital Corporation ("PNW") and Hawaiian Electric Industries, Inc. ("HE"). As previously discussed, PNW's largest operating subsidiary, APS, recently received a negative regulatory decision, and as a result, the share price of PNW decreased approximately 24 percent over a two-month period from October through November 2021. Therefore, similar to the reason that I exclude transformative transactions, because the stock price can be affected by one-time events, I also excluded PNW from the proxy group.

HE's operations are concentrated on the islands of Hawaii; therefore, the company faces geographic concentration risk. As noted in HE's 2021 Form10-K:

> The Company is subject to the risks associated with the geographic concentration of its businesses and current lack of interconnections that could result in service interruptions at the Utilities or higher default rates on loans held by ASB [American Savings Bank].[38]

The increased risk of service interruptions resulting from HE's geographic location, which could result in revenue loss and increased costs, is a risk unique to HE and would not apply to utilities located on the U.S. mainland. Furthermore, HE's unregulated operations, which represented approximately 33 percent of the company's operation income in 2021, are concentrated in the banking sector through the ownership of American Savings Bank ("ASB").[39] ASB also only operates on Hawaii; thus, all of the company's consumer and commercial loans are to

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[38] Hawaii Electric Industries, Inc., 2021 Form 10-K, at 23.

[39] *Id.*, at 86.

customers on Hawaii. If Hawaii were to face an adverse economic or political event, ASB could face severe financial effects given the company's geographic concentration in Hawaii.[40] Considering HE's unique geographical risks, I have excluded HE from my proxy group.

Q: What is the composition of your proxy group?

A: The screening criteria discussed above is shown in Schedule AEB-D2, Attachment 2 and resulted in a proxy group consisting of the companies shown in Figure 8.

FIGURE 8: ELECTRIC PROXY GROUP

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

[40] *Id.*, at 20.

VI. Cost Of Equity Estimation

Q: Please briefly discuss the ROE in the context of the regulated rate of return.

A: The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the cost of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q: How is the required ROE determined?

A: The required ROE is determined by using one or more analytical techniques that rely on market data to quantify investor expectations regarding the range of required equity returns. Informed judgment is applied, based on the results of those analyses, to determine where within the range of results the cost of equity for a company falls. As a general proposition, the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets, the proxy group companies, and the subject company's risk profile.

Q: What methods did you use to determine the Company's ROE?

A: I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, and the Bond Yield Plus Risk Premium Analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

VI.A. Importance of Multiple Analytical Approaches

Q: Why is it important to use more than one analytical approach to estimate the cost of equity?

A: Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. As a practical matter, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[41] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[42] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q: Is it important given the current market conditions to use more than one analytical approach?

A: Yes. As previously discussed, interest rates have been relatively low as a result of the Federal Reserve's accommodative monetary policy. The effect of the recent low interest rate environment was relatively high stock valuations and low dividend yields for utilities, which in turn result in DCF cost of equity estimates that understate the

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41 Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

42 Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

forward-looking cost of equity. As interest rates have increased recently, utility stock prices had trended down, yet as a result of the political turmoil associated with the war in Ukraine, investors have recently returned to utility stocks as a safe haven seeking to lower risk, increasing utility stock prices and resulting in lower dividend yields. However, as discussed previously, the electric utility sector is projected to underperform the broader market during the period when the rates established in this case are effective. This indicates that current dividend yields for utilities reflected in the DCF are projected to underestimate the cost of equity for the Company going forward.

Also as discussed, interest rates are projected to substantially increase over the next 12 to 18 months, which affects the CAPM in two ways: (1) the risk-free rate is lower than it is expected to be going forward, thus understating the CAPM result; and (2) because the market risk premium is a function of interest rates (*i.e.*, it is the return on the broad stock market less the risk-free interest rate), the market risk premium is higher than what it is expected to be going forward, thus overstating the CAPM result. The net effect of these impacts is that with interest rates and bond yields now rising, the expected cost of equity will be higher than is suggested by the CAPM using historical average yields. Thus, use of projected Treasury bond yields in the CAPM results in estimates that will be more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

During such a transitory period as this one, it is important to use multiple analytical approaches to moderate the impact that the recent low interest rate environment has had on the ROE estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period over which the rates being established will be in effect. Under these circumstances, relying exclusively on historical and even current assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect.

Q: Are you aware of regulatory commissions that have recognized the importance of considering the results of multiple models?

A: Yes. The Commission, as well as various other regulatory commissions have considered the results of multiple ROE estimation methodologies such as the DCF, CAPM, ECAPM and Bond Yield Plus Risk Premium models in determining the authorized ROE, including the Washington Utilities and Transportation Commission ("Washington UTC"),[43] the Michigan Public Service Commission ("Michigan PSC"),[44] the Minnesota Public Utilities Commission,[45] the Iowa Utilities Board,[46] and the New Jersey Board of Public Utilities.[47]

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[43] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, December 4, 2013, Order 05, n. 89; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, March 25, 2011, Order 06, ¶ 91.

[44] Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

[45] Docket No. G011/GR-17-563, Findings of Fact, Conclusions and Order, at 27; Docket No. E015/GR-16-664, Findings of Fact, Conclusions and Order, at 60-61.

[46] Iowa Utilities Board, Iowa-American Water Company, RPU-2016-0002, Final Decision and Order issued February 27, 2017, at 35.

[47] NJBPU Docket No. ER12111052, OAL Docket No. PUC16310-12, Order Adopting Initial Decision with Modifications and Clarifications, March 18, 2015, at 71.

For example, the Commission has stated that, "[f]inancial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity," noting the DCF, CAPM and Risk Premium approaches, and that "no one method is any more 'correct' than any other method in all circumstances," and that, "analysts balance their use of all three methods to reach a recommended return on equity."[48]

The Washington UTC has repeatedly emphasized that it "places value on each of the methodologies used to calculate the cost of equity and does not find it appropriate to select a single method as being the most accurate or instructive."[49] The Washington UTC has also explained that "[f]inancial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies."[50]

Additionally, in a 2018 DTE Gas Company rate proceeding, the Michigan PSC considered the results of each of the models presented by the ROE witnesses, which included the DCF, CAPM, and ECAPM in the determination of the authorized ROE.[51] In the proceeding, the Michigan PSC also considered authorized ROEs in other

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48 *See, e.g.*, Missouri Public Service Commission, Report and Order, File No. ER-2014-0258, May 12, 2015, at 64; Missouri Public Service Commission, Report and Order, File No. ER-2016-0285, May 13, 2017, at 15-16.

49 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, December 4, 2013, Order 05, n. 89.

50 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, March 25, 2011, Order 06, ¶ 91.

51 Michigan Public Service Commission Order, DTE Gas Company, Case No. U-18999, September 13, 2018, at 45-47.

states, increased volatility in capital markets and the company-specific business risks of DTE Gas.

VI.B. Constant Growth DCF Model

Q: Please describe the DCF approach.

A: The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and *k* is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q: What assumptions are required in the Constant Growth DCF model?

A: The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a price-