102. [DELETED]

102A. Xcel Energy is required to have a Board of Directors and provides to non-employee members of the Board of Directors compensation with equity shares through a stock equivalent plan.

102B. Each unit that sets director compensation under the stock equivalent plan has a value equal to one share of Xcel stock, directly aligning the non-employee directors' interests with shareholders'.

102C. SPS failed to meet its burden to prove the stock equivalent plan is not financially-based compensation.

102D. SPS's requested expense of $163,701 for the Stock Equivalent Plan expenses should be denied.

103. SPS has withdrawn its request for recovery of $3,565 in Xcel Energy executives' benefits.

104. SPS's requested amount of $634,765 for moving and relocation expenses, as adjusted downward by $37,984, is reasonable and necessary to attract employees.

Deferred Pension and OPEB Expense Recovery

105. SPS is requesting recovery of $3,583,510 of deferred pension and OPEB expense.

106. The amount of deferred pension and OPEB expense is reasonable and should be included in SPS's cost of service.

107. It is appropriate to amortize the deferred pension and OPEB expense over a two-year period.

Depreciation Expense

108. All of SPS's current depreciation rates were set in Commission orders that were based on negotiated settlements and are not precedential.

109. Except as otherwise stated below, SPS's depreciation study recommends appropriate and reasonable depreciation rates for SPS's steam production, other production, transmission, distribution, and general plant.

110. SPS's proposed service lives for production plant are reasonable, and are appropriately used to calculate SPS's production-plant-depreciation rates.

111. None of the parties proposed a net salvage value for production plant that was calculated using a plant-specific study of SPS's production plant.

112. The current positive 5% net salvage value for SPS's Production Plant was set in non-precedential Commission orders that were based on settlements in prior SPS rate cases.

113. The evidence does not support setting a positive net salvage value for SPS's production plant. SPS proved that its production plant has a negative net salvage value.

114. SPS did not propose the negative 8% net salvage value for production plant indicated by the dismantling cost study presented by SPS.

115. The model used in the dismantling cost study was originally developed for decommissioning nuclear plants, and SPS did not prove that the model had been appropriately adapted for use in estimating the cost of dismantling SPS's fossil plants.

116. The dismantling cost study contained a number of assumptions that overstate the net cost of dismantling SPS's fossil plants.

117. In rate cases for various Texas electric utilities, the Commission has approved a variety of net salvage values for production plant, including in many cases a negative 5% net salvage value. SPS proposed a negative 5% net salvage value based on the Commission orders approving a negative 5% net salvage value.

118. SPS did not prove that its Production Plant has a net salvage value of negative 5% or any negative number larger than negative 2%.

119. A negative 2% net salvage value is reasonable and appropriate based on the evidence and should be used for all of SPS's Production Plant.

120. Except for the net salvage value for Transmission Poles & Fixtures (Account 355), SPS's proposed service lives and net salvage values for Transmission Plant are reasonable and should be used to calculate SPS's Transmission Plant depreciation rates.

121. A net salvage value of negative 35% for Transmission Poles & Fixtures (Account 355) is reasonable and should be used to calculate SPS's depreciation rates for that account.

122. The evidence does not show that SPS should be ordered to conduct the study relating to Transmission Poles & Fixtures (Account 355) proposed by AXM.

123. SPS's proposed service lives and net salvage values for Distribution Plant are reasonable and should be used to calculate SPS's Distribution Plant depreciation rates.

124. [DELETED]

124A. SPS's proposed service lives for General Plant are reasonable and should be used to calculate SPS's General Plant depreciation rates.

125. SPS's proposed net salvage values for General Plant are reasonable, and are appropriately used to calculate SPS's General plant depreciation rates.

126. The evidence does not show that SPS should be ordered to conduct the study relating to Miscellaneous Intangible Plant (Account 303) Large Software Systems proposed by AXM.

127. [DELETED]

127A. An average service life of 10 years for Transmission Equipment–Light Trucks (Account 392.02) is reasonable and should be used to calculate SPS's depreciation rates for that account.

128. [DELETED]

128A. An average service life of 12 years for Transmission Equipment–Heavy Trucks (Account 392.04) is reasonable and should be used to calculate SPS's depreciation rates for that account.

Affiliate Charges

129. SPS's affiliates charged SPS $89,746,387 for services during the test year. The vast majority of these operations and maintenance (O&M) expenses – $89,669,175 – were for services rendered by XES. The remaining affiliate services were charged (or credited) to SPS by Northern States Power Company – Minnesota, or Public Service Company of Colorado.

130. After exclusions and pro forma adjustments, SPS sought to recover $86,844,330 in O&M affiliate charges.

131. XES follows a number of processes to ensure that: (1) affiliate charges are reasonable; (2) SPS and other affiliates are charged the same rate for similar services; and (3) the charges approximate the costs incurred by XES to provide the services.

132. The processes followed by XES include: (1) use of service agreements to define the level of service required and the cost of those services; (2) direct billing of affiliate charges when possible; (3) use of reasonable allocation methodologies for charges that cannot be direct billed; (4) billing its services without any mark-up, *i.e.* at cost billing; and (5) use of budgeting processes and controls to control spending.

133. The affiliate charges were grouped into 44 classes.

134. SPS properly removed lobbying costs from the costs of the External Affairs affiliate class. SPS's remaining costs in the External Affairs class, which are 12.5% of the total costs of this affiliate class, are not lobbying costs and are properly recoverable.

135. During the test year, XES incurred legal costs to defend itself against several employment discrimination claims, none of which were found to have merit. The portion of these legal costs allocated to SPS was $79,291 (total company). The employees in question were XES employees; all but one of the claims were asserted solely against XES; and no Xcel Energy operating companies were defendants. The XES employees in question performed jobs that benefited SPS, and it is appropriate that SPS pay its share of the defense costs for these claims.

136. [DELETED]

136A. Affiliate charges totaling $203,474 (total company) were made to SPS using multiple six-digit work orders that contained "New Mexico" or locations within New Mexico in their titles. Six-digit work orders are used to directly charge costs to specific Xcel Energy operating companies, but not to specific retail jurisdictions.

136B. SPS met its burden to prove the managerial-level work associated with these work orders benefitted Texas retail customers.

136C. It would be inconsistent and inequitable to include only a portion of the costs of work orders with Texas in the titles while also wholly excluding the costs of work orders with New Mexico in the title.

136D. The affiliate charges, totaling $203,474 (total company), associated with these work orders are reasonable and necessary expenses and are properly included in setting SPS's base rates.

137. A component of the shared facilities charges SPS incurred from affiliates included the carrying costs associated with those facilities. Because these carrying costs are unnecessary and unreasonable, $1,564,659 should be removed from SPS's affiliate expense. SPS should also make a corresponding decrease to FERC account 922 of $1,187,726 in revenue SPS has received related to carrying costs. This results in a net reduction of $376,933 (total company).

138. SPS agreed to remove $2,475 in Life Event costs, which were contained in multiple affiliate classes, from its application.

139. SPS agreed to remove a $104 charge that was due to a timekeeping entry error from its application.

140. All remaining affiliate transactions for which recovery was sought were reasonable and necessary, were allowable, and were charged to SPS at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

<u>Purchased Capacity Costs</u>

141. SPS's capacity-related expenses generally include capacity or demand and non-fuel items, such as O&M expenses or turbine start charges. SPS's capacity-related expenses are reasonable and necessary and are appropriately included in base rates.

142. SPS's proposed changes to purchased power agreement expenses for decreases due to the expiration of purchased power agreements and cost increases based on contractual terms represent appropriate known and measurable adjustments to test-year expenses.

143. Because the term of the second Calpine Energy Services purchased power agreement (Calpine II) extends through May 31, 2019, but the test year only contained one month of Calpine II capacity costs, SPS's adjustment to annualize capacity costs for the Calpine II agreement is an appropriate known and measurable adjustment to test-year expenses.

Coal Procurement Expenses

144. Because SPS's proposed changes to coal procurement costs reflect contractual terms, they represent appropriate known and measurable adjustments to test-year expenses.

145. SPS's coal procurement expenses are reasonable and necessary.

SPP and Other Transmission Charges and Revenue

146. SPS is both a transmission owner and a transmission customer within the Southwest Power Pool (SPP).

147. As a transmission owner, SPS is subject to charges calculated in accordance with the SPP Open Access Transmission Tariff (OATT).

148. Transmission customers within SPP must pay Schedule 11 expenses related to transmission upgrades designated as Base Plan Upgrades.

149. Transmission owners that build base plan upgrades are entitled to receive Schedule 11 revenues from SPP.

150. In the test year, SPS paid $54,595,476 (total company) of Schedule 11 expenses, and it received $60,836,125 (total company) of Schedule 11 revenues.

151. Instead of using its test-year Schedule 11 expenses and revenues to calculate the cost of service, SPS used a calculation based on SPP's October 2014 Revenue Requirement and Rates (RRR) file, adjusted to reflect the return on equity that SPS proposes in this case instead of the return on equity authorized by FERC that underlies the October 2014 RRR file.

152. Using its method described above, and under the assumption that SPS's proposed post-test-year adjustments to rate base are rejected, SPS calculated $77,593,999 (total company) of Schedule 11 expenses and $60,251,331 (total company) of Schedule 11 revenues.

153. SPS proposed that if the Commission adopts a return on equity different from that proposed by SPS, SPS's calculation of the Schedule 11 expenses and revenues be adjusted to use the return on equity the Commission sets in this case.

154. SPP changes its RRR files often. For example, SPP stopped using the October 2014 RRR file when its January 2015 RRR file update took effect, and the RRR file has changed several times since then.

155. Shifts in variables in the RRR file can cause an SPP member's Schedule 11 expenses net of its Schedule 11 revenues to be significantly higher or lower.

156. Under SPS's methodology, SPS's calculated Schedule 11 revenues and expenses would differ substantially depending on the RRR file used. For example, using the October 2014 RRR file would indicate a significant Schedule 11 net expense, and using the January 2015 RRR file would indicate a significant Schedule 11 net credit.

157. The October 2014 RRR file is not a known and measurable change to SPS's test year Schedule 11 revenues and expenses, and using the October 2014 RRR file to calculate SPS's Schedule 11 revenues and expenses would be unreasonable.

158. SPS's cost of service in this case should be determined using SPS's actual Schedule 11 revenues and expenses, which are based on the FERC return on equity that SPP actually used to calculate SPS's Schedule 11 revenues and expenses, not the hypothetical return SPS calculated to account for differences in the returns on equity approved by the Commission and FERC.

159. Differences in regulatory treatment by FERC and the Commission are not limited to setting different returns on equity at a particular time. The rate-setting methodologies used by FERC and the Commission differ in numerous respects.

160. SPS's actual Schedule 11 expenses and revenues for the test year are reasonable and necessary and should be used to calculate SPS's cost of service.

161. Schedule 1-A charges are charges applied to all transmission service under the SPP OATT to cover SPP's expenses related to its administration of the OATT.

162. SPS's test year Schedule 1-A charges were $11,895,856 (total company). SPS removed $3,294,127 attributable to wholesale load and increased the Schedule 1-A expenses by $878,143 (total company) to account for the increase in the Schedule 1-A fee approved by the SPP Board of Directors in October 2014.

163. The adjustment proposed by SPS for Schedule 1-A charges is known because it has already occurred and SPS is currently paying the increased charge. The amount is also measurable because it is calculated on a megawatt-hour basis. The proposed Schedule 1A expense of $9,479,871 (total company) is reasonable and should be included in the cost of service.

164. SPS incurred $8,475,178 of costs during the test year for a transmission reservation across the Lamar Direct Current Tie, a transmission tie between SPS and Public Service Company of Colorado.

165. SPS proposed a known and measurable adjustment of $390,182 to the Lamar Direct Current Tie test-year costs to reflect that Public Service Company of Colorado's FERC-approved formula rate increased on January 1, 2015.

166. The adjustment is known because it has occurred and SPS is currently paying the higher rate approved by FERC. The adjustment is also measurable because it is charged on fixed amount of capacity.

167. SPS's requested amount of $8,865,360 for Lamar Direct Current Tie costs is reasonable and should be included in the cost of service.

168. As a transmission owner within SPP, SPS received transmission revenues from transmission customers for point-to-point service under Schedule 7 and Schedule 8.

169. In the test year, SPS received $4,869,637 of Schedule 7 and Schedule 8 revenues from SPP. SPS proposed to increase the revenues by $457,850 to reflect higher transmission rates approved by FERC.

170. The adjustment is known because the increase in transmission rates has occurred, and it is measurable because it is charged on a megawatt-hour basis.

171. SPS's requested Schedule 7 and Schedule 8 revenue of $5,327,487 is reasonable, and that amount should be included as a revenue credit in the SPS cost of service.

__O&M Cost Containment__

172. SPS presented a benchmarking study comparing its O&M costs to those of groups of peer utilities.

173. The benchmarking study presented by SPS shows that SPS's overall O&M expenses are reasonable compared to those of peer utilities.

174. SPS's benchmarking study did not include a comparison of O&M expense escalation rates.

175. DOE presented an O&M benchmarking study that compares SPS's administrative and general O&M expenses (A&G expenses) and distribution O&M expenses to those of a peer group of utilities.

176. SPS's and DOE's benchmarking studies were reasonably constructed and are reasonable tools for evaluating SPS's performance at managing O&M expense with respect to the matters analyzed in each study.

177. DOE's benchmarking study indicates that SPS ranks in the bottom or below average quintiles for controlling A&G expense escalation.

178. DOE's benchmarking study indicates that SPS ranks in the bottom or below average quintiles for controlling distribution O&M expense escalation.

179. Based on its benchmarking study, DOE proposed disallowances of $17.2 million (total company) of A&G expense and $3.2 million (total company) of distribution O&M expense.

180. DOE's proposed disallowances would apply the same standard to disallow SPS's A&G and distribution O&M expenses regardless of whether they are affiliate expenses.

181. DOE's benchmarking study analyzed only comparative cost growth rates, not circumstances underlying those growth rates. It did not analyze whether the increase in SPS's A&G and distribution O&M expenses resulted from imprudence.

182. The evidence does not show that the increases in SPS's A&G and distribution O&M expenses resulted from imprudence.

183. SPS presented some evidence of reasons its A&G and distribution O&M expenses have escalated.

184. DOE's proposed adjustments should not be made in this case.

185. DOE's study indicates that further investigation of the substantial escalation of SPS's A&G and distribution O&M expenses is warranted.

186. SPS should be required to investigate (including work with affiliates regarding their charges) and to detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M costs, steps being taken to reduce them, and the timing and cost impact of those steps.

Fleet Fuel Expense

187. Fleet fuel expense reflects the costs that SPS incurs to purchase gasoline and diesel for its fleet of vehicles.

188. SPS's fleet fuel expense during the test year was $5,054,776.

189. Staff proposed to make an adjustment to the test-year level of fleet fuel expense to reflect the reduction in fuel costs since the end of the test year.

190. Staff's proposed adjustment to fleet fuel expense is not known and measurable because fuel prices fluctuate, and it cannot be determined what fuel prices will be during the time the rates set in this case are in effect.

Renewable Energy Credits

191. SPS accrues renewable energy credits (RECs) in connection with purchases of renewable energy.

192. SPS obtains RECs through five long-term purchased power agreements, of which one is unbundled (*i.e.*, the prices of energy and RECs are separately stated) and the other four are bundled.

193. Currently, (1) SPS's revenues from sales of its RECs are a credit to eligible fuel expense; (2) for SPS's bundled purchased power agreements, the imputed value of the RECs is deducted from the total contract price in eligible fuel expense; and (3) SPS's costs for unbundled and bundled RECs are included in base rates.

194. In this case, SPS proposed to continue recovering REC expense in base rates; to continue allowing REC sales revenues to be credited through fuel expense; to continue allowing each state commission to establish the value of RECs generated in that state; to reduce the imputed price of bundled RECs from $1.10 per REC to $0.95 per REC; and to share margins from REC sales on a basis of 90% to customers and 10% to SPS.

195. SPS's proposals to continue recovering REC expense in base rates and to continue allowing each state commission to establish the value of RECs generated in that state are reasonable.

196. A price of $0.64 per bundled REC is reasonable and should be imputed to bundled RECs going forward.

197. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not show good cause to make an exception to that rule. REC sales credits should instead be included in SPS's base rates.

198. [DELETED]

198A. Commission Staff's calculation of a base rate credit of ($444,376), offsetting SPS's REC costs against SPS's REC sales revenues, is reasonable and should be included when setting SPS's base rates.

198B. Commission Staff's calculation reflects that a prudent utility would eventually sell all of its excess RECs.

198C. Commission Staff's calculation is consistent with the imputed price per bundled REC.

199. SPS did not prove that its proposal to allocate margins from REC sales on a basis of 90% to customers and 10% to SPS is reasonable or necessary or would produce any net benefit to customers.

Advertising, Contributions, and Dues

200. The Commission allows recovery for ordinary advertising, contributions, and donations as a cost of service as long as the sum of such items does not exceed three-tenths of 1.0% of the gross receipts for services rendered to the public (a 0.3% cap). 16 TAC § 25.231(b)(1)(e).

201. SPS's total advertising, contributions, and dues expense, without the 0.3% cap, reduced by the ALJs' adjustment of $686,619, is reasonable.

Amortization Expense for Regulatory Assets

202. SPS's proposal to include $1.5 million of historical energy efficiency expense in the cost of service is reasonable and consistent with the Commission's orders in prior SPS base rate cases.

203. SPS's proposal to include $2.8 million of historical REC expense in the cost of service is reasonable and consistent with the Commission's orders in prior rate cases.

204. SPS's proposal to include $34,898 of regulatory meter cost in the cost of service is reasonable.

Rate Case Expenses

205. SPS initially proposed to include in cost of service $2,521,940 of unamortized rate case expenses incurred in two prior SPS dockets, along with the amount of rate case expenses incurred or expected to be incurred in this docket.

206. SPS further proposed to offset those amounts by the remaining unamortized balance of the gain on sale of assets to Lubbock Power & Light, which was $2,226,277, and by the remaining unamortized balance of a credit attributable to the TUCO, Inc. overcharge, which was $83,753.

207. On March 6, 2015, the ALJs severed issues relating to the rate case expenses incurred in this docket and moved them to Docket No. 44498, which left the $2,521,940 of rate case expenses from prior dockets to be addressed in this case.

208. SPS proposed that the Lubbock Power & Light and TUCO, Inc. amounts be offset against the $2,521,940, which leaves a net rate case expense balance of $211,911.

209. It is reasonable to offset the Lubbock Power & Light and TUCO, Inc. amounts against the rate case expenses from prior dockets.

210. The $211,911 is a one-time expense. To avoid possible over-recovery, it should be recovered not through base rates but rather through a rider set to recover that specific amount.

211. Because $211,911 is a relatively small amount and Docket No. 44498 is pending, that amount should be recovered through the rider approved in that docket.

212. Consistent with Commission precedent, SPS should not be allowed to earn a return on unpaid rate case expenses.

213. An opportunity to challenge the reasonableness of SPS recovering the $211,911 was provided in this case. SPS proved that it should recover that amount, and that issue should not be re-litigated in Docket No. 44498.

Miscellaneous Services Revenue

214. SPS's proposal to include approximately $990,000 of miscellaneous services revenue in the cost of service is reasonable and should be approved.

Pole Attachment Fee Revenue

215. SPS included in the cost of service a credit of $1,377,041 to reflect the amount of pole attachment revenues SPS received in the test year.

216. SPS agreed that it is appropriate to increase the pole attachment revenue by $413,379 to reflect a normal amount of pole attachment revenues.

217. It is reasonable to include $1,790,420 of pole attachment revenues in the cost of service.

Interest on Customer Deposits

218. SPS calculated interest using the Commission-approved customer deposit interest rate of 0.09% per annum.

219. Effective January 1, 2015, the Commission-approved customer deposit interest rate fell to 0.07% per annum.

220. It is reasonable to use the updated customer deposit interest rate, which reduces the customer deposit interest balance by $1,627.

Uncollectible Expense

221. SPS requested recovery of $3,910,703 in uncollectible expense based on the test-year amount of uncollectible expense recorded in FERC Account 904.

222. The test-year level of expense is representative of the amount of uncollectible expense that SPS is likely to experience in the future. It is reasonable to include that amount in the cost of service.

Taxes

223. SPS inadvertently omitted the Research and Experimentation credit from the calculation of income tax expense.

224. It is reasonable for the Research and Experimentation credit to be included in the calculation of income tax expense.

225. A Research and Experimentation credit in the amount of $330,071 (total company) should be included in the cost of service.

226. SPS incurs property taxes in each jurisdiction in which it has tangible assets, including production plant, transmission plant, distribution plant, and general plant.

227. SPS made several adjustments to the test year property tax expense, including an adjustment to bring the property balances to June 30, 2014.

228. The property tax expense included in the cost of service should be calculated based on the plant balances as of the end of the test year.

229. It is reasonable to use actual property tax balances from 2014 to determine the ratio of tax to plant balances.

230. Property taxes attributable to CWIP should be capitalized to CWIP rather than charged to the current period operating expense. Capitalizing those property taxes to CWIP is reasonable and in compliance with the FERC Uniform System of Accounts.

231. Total company property tax expense should be calculated by reflecting the actual 2014 property-tax-to-plant ratio applied to the June 30, 2014 plant in service balance, exclusive of CWIP. Thus, the reasonable level of total company property tax expense is $29,723,945.

232. SPS's PUC assessment tax should be removed from FERC Account 928 and reclassified into FERC Account 408, because the PUC assessment tax is a gross receipts tax.

Baselines

233. It is necessary to set baselines for the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor.

234. Consistent with the Commission's initial findings in this proceeding, SPS filed revised calculations of the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor baselines for review and comment by the parties.

235. The baselines set forth in Exhibit __ to this Order reflect the Commission's decisions in this case.

Miscellaneous Preliminary Order Revenue Requirement Issues

236. SPS's requested level of fees for the letter of credit that SPS posts for participation in SPP's transmission congestion rights auction is reasonable.

237. SPS has complied with all requirements of the Commission's final order in *Application of Southwestern Public Service Company for Authorization to Refund Amounts Received from Tri-County Electric Cooperative, Inc. Associated with Docket No. 42004*, Docket No. 44609, Order (Jul. 2, 2015).

237A. SPS should receive a Texas retail base revenue decrease of $4,025,973.

Present Revenue

Weather Normalization Adjustment

238. It is reasonable for SPS to calculate its normal weather based on a 10-year period in order to be consistent with the Commission's decision to use a 10-year period in the most recent SWEPCO base rate case, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing (Mar. 6, 2014).

239. SPS used weather data in developing its model to calculate the weather normalization adjustment that adequately represented the weather in SPS's service area.

240. The test year heating degree days were 9.7% above normal, the test year cooling degree days were 6.5% above normal, and the test year precipitation was 13.4% below normal.

241. It is reasonable for SPS to adjust its test-year sales for certain customer classes to remove the effects of abnormal weather, and to use its model to calculate the adjustment.

242. It is reasonable for SPS to exclude the test year from the time period used to develop normal weather because including the test year creates a bias in the weather variance analysis.

Annualized Revenue for Transmission-Level Customer 8

243. SPS properly included a known and measurable adjustment, increasing the test year billing determinants to reflect Customer 8's increased usage after the customer installed a second transformer to provide service to additional processes at that customer's facility.

Adjustment to Post-Test Year Billing Determinants

244. SPS properly adjusted the test year billing determinants to reflect known and measurable changes through December 31, 2014.

245. SPS properly matched the billing determinants with the period of post-test year plant adjustments, and it updated the customer class allocation factors to reflect the calendar year 2014 information.

Inter-class Cost Allocation

Demand Allocation

246. [DELETED]

246A. The only aspect of SPS's average-excess-demand coincident-peak calculation that was contested in this proceeding was SPS's calculation of the system load factor by averaging the monthly peak for the four months of June through September, adjusted for loss (4CP).

247. [DELETED]

247A. Commission Staff, TIEC, Occidental, and State Agencies argued SPS should have instead based its system load factor on the single highest system peak, adjusted for loss (1CP).

248. [DELETED]

248A. Commission Staff stated that use of 1CP to calculate the system load factor best reflects cost causation because SPS uses the single system peak for resource planning.

249. [DELETED]

249A. TIEC cited to the Southwest Power Pool's requirement that its members have capacity margins based on 1CP.

250. [DELETED]

250A. SPS's witness, Mr. Luth, conceded that use of a 1CP system load factor is reasonable.

251. [DELETED]

251A. SPS's system load factor used for allocating demand should be based on 1CP.

252. [DELETED]

253. [DELETED]

254. [DELETED]

255. [DELETED]

256. [DELETED]

Radial Lines

257. [DELETED]

257A. For transmission-facility costs other than radial lines, SPS has traditionally allocated the costs among all customer classes using the DTRAN allocator.

258. [DELETED]

258A. SPS did not have adequate load research data for the individual customers on radial lines to determine what contributions they make to system peaks.

259. [DELETED]

259A. Direct allocation of the costs of radial transmission lines would be inconsistent with the manner in which transmission costs have traditionally been allocated in Texas. For example, in the Electric Reliability Council of Texas (ERCOT) footprint, the costs of transmission infrastructure are generally pooled and allocated system wide.

260. [DELETED]

260A. It is reasonable to allocate the costs of SPS's transmission facilities, including radial lines, to all classes using SPS's DTRAN allocator.

261. [DELETED]

262. [DELETED]

263. [DELETED]

264. [DELETED]

265. [DELETED]

General Plant and Intangible Plant

266. It is reasonable to allocate General and Intangible Plant (G&I Plant) costs among classes primarily on the basis of Salaries and Wages Excluding Administrative & General (SALWAGXAG).

267. The use of a labor allocator, such as SALWAGXAG, is consistent with cost-causation principles because G&I Plant costs are driven largely by the needs of employees.

268. The National Association of Regulatory Utility Commissioners Cost Allocation Manual contemplates the use of a labor allocator for G&I Plant costs.

269. The Commission's rate filing package for transmission and distribution utilities is not a rule and does not apply to vertically integrated utilities such as SPS.

270. Because G&I Plant is driven primarily by labor, SPS appropriately used the SALWAGXAG allocator to allocate those costs among the classes.

Miscellaneous Revenue

271. It is reasonable to allocate revenue from miscellaneous service charges and returned check fees based on the distribution plant in service allocator because the charges originate from customers that take service at distribution voltage.

272. SPS's treatment of miscellaneous service charges and returned check fees is consistent with treating uncollectible expense as a system cost on the uncollectible expense side rather than as an expense attributable to a single class.

Mutual Aid

273. SPS provides mutual aid to other utilities to help respond to natural disasters.

274. Under mutual aid agreements between SPS and other utilities, SPS receives reimbursement for the assistance it provides.

275. It is reasonable to allocate mutual aid reimbursement to classes on a total plant basis.

Electric Vehicle and Fuel Tax Credit

276. SPS's allocation of electric vehicle and fuel tax credits as overhead costs based upon labor is reasonable.

Separating Residential Service and Residential Service with Electric Space Heating for Purposes of Allocating Distribution Costs

277. [DELETED]

277A. It is unreasonable for SPS to allocate distribution costs separately to the customers who take service under the general-residential-service rates and the customers who take service under the rates for residential service with electric space heating because all of these customers compose a single residential class.

277B. SPS's distribution costs should be allocated to the Residential Class as a whole rather than separately to the general-residential-service customers and residential-space-heating customers.

Distribution Substations Allocator

278. SPS properly allocated the costs of distribution substations among customer classes based on a non-coincident peak allocator.

279. Distribution substations are built by SPS to transform transmission voltage and provide distribution voltage to customers taking service at distribution voltage in localized areas.

280. The substations do not serve transmission voltage customers.

281. The substations are not sized to handle the system peak, but instead are sized to handle the customer loads in specific localized areas of the system.

282. A non-coincident peak allocation better reflects the end-use load characteristics of the transformation provided at the substations and is, therefore, reasonably applied.

__Account 368 – Distribution Line Transformers__

283. It is reasonable to distinguish between capacitors and transformers for purposes of allocating costs within FERC Account 368.

__Account 556 – System Control Dispatching-Generation__

284. SPS incurs costs recorded in FERC Account 556 for system control and dispatching of the production system.

285. Load dispatching reflects SPS's operation of its production, transmission, and distribution systems.

286. Load dispatching is a daily operation that occurs throughout the year every hour of every day, and must meet reliability requirements during peak and low-demand times.

287. Peak demand usage is included in each class's average demand over the course of a year.

288. A 12CP demand allocator is based on the average coincident peak for each month of the year.

289. The 12CP demand allocator balances the requirement to dispatch load to meet average usage and the requirement to dispatch load to meet maximum annual peak demand.

290. SPS reasonably allocated system control and dispatching costs among customer classes based on 12CP demand in this case and, based on the daily nature of dispatching, average usage throughout the year is an appropriate method for allocation.

__Accounts 561.1-.3 – Load Dispatch – Transmission and Account 581 – Load Dispatching-Distribution__

291. SPS properly allocated transmission-related load dispatch costs recorded in FERC Account 561 using an average demand allocator.

292. It is reasonable for SPS to allocate distribution-related load dispatch costs recorded in FERC Account 581 using an average demand allocator.

293. SPS dispatches its system every second of every day throughout the year, at peak times and at low-demand times to ensure reliability of the SPS system.

294. Annual line loss-adjusted kWh represents the use of the SPS system throughout the year by a customer class.

295. When the annual kWh of each customer class is compared to other customer classes, the comparison represents each class's relative average use of the SPS system throughout the year, and is the appropriate method of allocating costs for dispatching the SPS system because the activity occurs all day, every day, all year long.

Regional Market Expenses (Accounts 575.1, .2, .5, .6, .7, and .8)

296. Regional market expenses refer to costs charged to SPS by SPP to defray the costs of administering the SPP Open Access Transmission Tariff and of operating SPP's Integrated Marketplace.

297. These expenses are caused by SPS's daily operations undertaken to provide transmission system reliability, which is important throughout the year, both at off-peak and peak demand times.

298. SPS properly allocated the regional market expense included in FERC Account 575 among customer classes based largely on the DTRAN allocator because the majority of these costs represent charges from SPP that are based on transmission peaks.

299. SPS properly allocated smaller amounts of regional market expense according to an energy allocator because such method weights the allocation on the basis of usage throughout the year, including during peak times.

Account 593 – Distribution Maintenance of Overhead Lines

300. Most vegetation management relating to overhead lines in SPS's system occurs on the primary distribution system.

301. In numerous areas of SPS's system, there are secondary lines under the primary lines.

302. SPS's guidelines indicate that the company does not conduct routine pruning on secondary lines.

303. Even if the secondary system occasionally benefits from tree trimming done on SPS's primary system, the secondary system did not cause the expense of such trimming.

304. The costs of vegetation management relating to overhead lines in the SPS system which are caused by the secondary system are very minimal.

305. Allocating vegetation management costs between the primary and secondary distribution systems based on total overhead plant costs does not tend to promote cost of service-based rates.

306. It is more reasonable and consistent with cost causation to classify vegetation management costs as 98% to the primary distribution system and 2% to the secondary distribution system.

Account 902 – Meter Reading Costs

307. [DELETED]

307A. SPS proposed to allocate meter reading costs based on a weighted number of customers. Specifically, SPS counted each primary general, secondary general, or LGS-T customer as 5.97517 customers. In contrast, all customers in the others classes were each counted as a single customer.

308. [DELETED]

308A. SPS failed to prove its proposed weighting of customer counts is reasonable because the proposal was not based on sufficient data nor systematic analysis.

309. [DELETED]

309A. It is reasonable to allocate Account 902 based on the actual customer count, not SPS's proposed weighted customer count.

Account 904 – Uncollectible Accounts

310. SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.

311. Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.

Major Account Representatives (Account 908 – Customer Assistance Expenses and Account 912 – Demonstrating and Selling Expenses)

312. SPS employs major account representatives that serve large customers in the C&I classes (Secondary General Service, Primary General Service, and LGS-T classes), but not

customers in the Residential and Small General Service classes or smaller customers in the Secondary General Service class.

313. Assigning a weighting factor of ten to the Primary General Service and LGS-T classes was appropriate to reflect that smaller Secondary General Service customers are not typically served by these representatives.

314. SPS's proposal to allocate costs of major account representatives to the C&I classes (except for smaller Secondary General Service customers) is reasonable and consistent with cost causation principles.

Outside Services-Legal (Account 923)

315. SPS properly allocated the costs incurred in FERC Account 923 for outside legal services on the basis of the SALWAGXAG allocator.

316. It is reasonable to use the SALWAGXAG allocator because SPS engages outside counsel to perform only the work that exceeds the capacity of its in-house legal staff, and the costs of the in-house legal staff are allocated based on SALWAGXAG.

Contributions, Dues, and Donations

317. SPS reasonably allocated the costs of contributions, dues, and donations among customer classes using a labor allocator, SALWAGES, because contributions, dues, and donations are tied to employee activities.

Account 926 – Employee Pensions and Benefits

318. It is reasonable to allocate the employee pension and benefit costs recorded in FERC Account 926 among customer classes using the SALWAGXAG allocator, and the method matches the jurisdictional allocation method.

Historical Energy Efficiency Costs

319. Before 2012, SPS was not subject to the Energy Efficiency Cost Recovery Factor rule, and therefore it recovered energy efficiency costs in base rates.

320. In *Application of Southwestern Public Service Company for Authority to Change Rates, to Reconcile Fuel and Purchased Power Costs for 2006 and 2007, and to Provide A Credit for Fuel Cost Savings,* Docket No. 35763, Order (June 2, 2009), Docket No. 35763, a 2008

SPS base rate case, the parties agreed SPS would be allowed to recover the energy efficiency expenses incurred up to that time over a ten-year period.

321. Customers in the LGS-T classes did not receive services from SPS's historical energy efficiency programs prior to 2008, while the other classes did receive such services.

322. The LGS-T classes did not cause the costs incurred by SPS's historical energy efficiency programs.

323. Industrial customers such as those in the LGS-T classes have economic incentives to fund their own energy efficiency measures, at their own expense and to the benefit of SPS's system and other customers.

324. It is more consistent with cost causation principles to allocate SPS's historical energy efficiency costs to only the classes that received service from the programs, using an energy allocator.

Municipal Franchise Fees

325. SPS imposes two levels of municipal franchise fees: (1) a base level of 2-3% (depending on the franchise agreement) that is embedded in base rates and charged to all customers except for LGS-T customers located outside of municipal boundaries; and (2) an incremental amount that is collected from only the customers in the particular franchise jurisdiction charging the incremental amount.

326. Municipal franchise fees are incurred based solely on in-city electricity usage and the resulting revenues collected from those sales.

327. Based on cost causation principles, it is reasonable to allocate all municipal franchise fees on the basis of in-city revenues.

Determination of Customer Classes for Allocation and Rate Design Purposes

328. It is reasonable to adopt the following classes for purposes of cost allocation and revenue distribution in this case:

- Residential (including both Residential Service and Residential Service with Electric Space Heating, broken out separately);
- Small General Service;

- Secondary General Service (including Service Agreement Summary customers SAS-4 and SAS-8, as well as standby customers);
- Primary General Service (including standby customers);
- Large General Service – Transmission (69 kV);
- Large General Service – Transmission (115+ kV);
- Small Municipal and School;
- Large Municipal;
- Large School;
- Street Lighting; and
- Guard or Area Lighting.

329. The group of 11 classes is large enough to draw meaningful distinctions between customers based on their usage characteristics and the demands they make on the electrical system.

330. The group of 11 classes remains sufficiently general to avoid decomposition of costs and rates into specialized end uses.

331. In prior cases, SPS allocated costs to the customer classes as a whole using the AED-4CP allocation factor, with all costs allocated to the C&I classes considered together. SPS then distributed the revenue requirement to the C&I classes based on billing demand.

332. In this case, SPS reasonably allocated costs separately to the individual C&I classes using the AED-4CP allocation factors, and then it performed the class revenue increase distribution by calculating the class revenue targets based on that same approach.

333. SPS's allocation approach for the C&I classes will reduce the possibility of hidden subsidies between these classes and properly considers the differences between these classes concerning their effects on the SPS system.

334. SPS's allocation approach is reasonable because it allocates costs more consistently with cost-causation principles than the method it used in prior cases.

Revenue Distribution

Gradualism Adjustment

335. [DELETED]

335A. The rates adopted in this proceeding reflect a less than 1% decrease to SPS's Texas retail revenue requirement.

335B. The revenue responsibilities of all classes, except the Street Lighting class, increase or decrease nor more than 14% from their present revenue responsibilities.

335C. The Street Lighting class's revenue responsibility will increase 24.28%. However, the Commission previously determined in Docket No. 40443 that an increase as large as 29% did not warrant rate mitigation.

336. [DELETED]

336A. No party proved that an adjustment for gradualism, which moves away from cost-based rates and requires cross-class subsidization, is appropriate in this proceeding.

337. [DELETED]

337A. SPS's request that the maximum increase in rates for any one class be capped at 200% of the system average increase, and that no class receive a rate decrease, is unreasonable and is not adopted.

337B. All other gradualism-adjustment proposals, including those of TIEC, Occidental, and AXM, are unreasonable and are not adopted.

337C. Each class's rates set in this proceeding should be based on the costs to serve that class.

Proposed Revenue Distribution

338. SPS's proposed revenue distribution is reasonable and consistent with cost causation principles.

Classes for Revenue Distribution in Future Cases

339. It is inappropriate for the Commission to determine parameters or requirements for rate classes to be approved in future base-rate proceedings.

339A. The Commission approves the following 11 rate classes in this base-rate proceeding: residential service; small general service; secondary general service; primary general service; large general service – transmission, 69-115kV; large general service – transmission, 115kV+; small municipal and school service; large municipal service; large school service; municipal and state street lighting; and guard- and flood-lighting service.

Rate Design

Customer Charge

340. The cost of service to the Residential Service class has increased, and therefore the service connection charge should also increase.

341. Increasing the service connection charge to the Residential Service class will reduce the amount of capacity costs caused by that class being paid by customers with higher load factors that use capacity more efficiently.

342. The full, component cost of service to a customer in the Residential Service class is $11.42 per month.

343. SPS's proposal to increase the monthly customer charge for the Residential Service class from the present charge of $7.60 to a proposed charge of $9.50 is reasonable.

Design and Future of Residential Service with Electric Space Heating Rates

344. SPS's request that the Residential Space Heating tariff be closed to new customers as of January 1, 2016 is reasonable.

345. Higher load factors in the winter months for Residential Service With Electric Space Heating customers would unreasonably result in moving rates for the Residential Service and Residential Service with Electric Space Heating subclasses classes further from cost causation principles if the winter discount for Residential Service with Electric Space Heating customers is not increased.

346. SPS's proposed $.05 per kWh increase in the winter discount rate for Residential Service with Electric Space Heating customers is reasonable and comports with cost causation principles.

Residential Time of Use Rates

347. SPS's proposal to offer an alternative, experimental Time of Use (TOU) rate rider for residential customers is reasonable.

348. The Residential TOU rate option will provide a reasonable alternative to future residential customers with electric space heating or other, significant non-summer consumption.

349. SPS will immediately begin communicating with its customers through bill inserts, website information, and direct contact from service representatives regarding TOU rates.

Small General Service

350. SPS's proposal to an increase the customer charge from $12.67 per month to $12.70 per month for the Small General Service customers is reasonable and reflects the actual customer-related cost for the Small General Service class.

Secondary General Service

351. SPS's proposed rate design for the Secondary General Service class is reasonable.

Primary General Service

352. Both Staff's and SPS's cost of service studies indicate that rates based on cost are higher for the Secondary General Service class than the Primary General Service class.

353. The rate differentials between the demand rates of the Secondary General Service class and the Primary General Service Class at other vertically integrated utilities in Texas are similar to the differentials between those two classes in SPS's cost of service study.

354. A widespread ratchet on Primary General Service customers may cause unreasonable adverse bill impacts on customers with significant off-peak seasonal loads or smaller customers in that class.

355. A demand ratchet would produce improper pricing signals for seasonal customers that have significantly higher loads during the off-peak non-summer months than during the summer months.

356. A demand ratchet may present difficulties for smaller Primary General Service customers that are similar to the kW demand billing difficulties for some Secondary General Service customers that the Rule of 80 is designed to assist.

357. It is not reasonable to establish a demand ratchet for Primary General Service customers.

358. It is not reasonable for SPS to adjust its revenue distribution by pooling the production, transmission, and primary capacity costs for the Primary General Service and Secondary General Service classes and allocating them according to billing demand.

359. It is reasonable and consistent with cost causation principles to allocate production, transmission and primary distribution capacity costs for the Primary General Service and Secondary General Service classes separately to each class according to billing demand.

LGS-T

360. SPS should not be required to present a primary transformation or primary substation service class or rate in its next rate case because such a class or rate is unnecessary.

361. It is inappropriate for the Commission to make decisions in this proceeding regarding rate classes for a future rate case.

362. SPS's current approach of leasing individual substations at replacement cost directly assigns substation costs to the very large customers that use each substation and is reasonable.

363. SPS's approach ensures that all costs from remote substations are recovered from the LGS-T customers that use them, and thus comports with cost causation principles.

Collection of Account 908 – Customer Assistance Expenses and Account 912 – Demonstration and Selling Expenses

364. Major account representatives are a service SPS makes available to its customers and is therefore a customer-related cost.

365. It is reasonable for SPS to recover part of this cost from the Secondary General Service class through a service availability charge and the rest through energy and demand charges.

Rule of 80 vs. Rule of 70

366. It is not appropriate or reasonable to revise Tariff Sheets Nos. IV-18, IV-175, and IV-182 to change the Rule of 80 to a Rule of 70.

367. Neither the Rule of 80 nor the Rule of 70 accounts for the timing of low load customers' maximum demand, so both could allow for billing reductions for usage during system peaks.

368. Moving from the Rule of 80 to the Rule of 70 will have a significant effect on the number of low load factor customers, including municipal customers, that will have to pay full demand charges.

369. The costs incurred by SPS as a result of the spikes of demand from low load factor customers at peak hours are considerably lower than the ordinary demand charge.

370. SPS load research data shows that low load factor customers have a very low coincidence with the system peak.

371. The Rule of 80 and the Rule of 70 are both generally cost of service based rates.

372. SPS did not show that moving from the Rule of 80 to the Rule of 70 will bring rates closer to cost of service.

373. It will take time to orient the low load factor customers to the experimental TOU and Low Load Factor rates, and it is unclear whether these rates will offer the same type of mitigation from overly high demand charges to the majority of these customers as does the Rule of 80.

Amarillo Recycling

374. It is reasonable to delete Electric Tariff Sheet No. IV-199 – the Service Agreement Summary applicable to ARC.

375. SPS is offering a Low Load Factor rate, which will be available to all customers served under the Secondary General Service class and the Primary General Service class that have a 25% or less average monthly load factor.

376. The proposed Low Load Factor rate will help ARC control its electric bill, provided that ARC can provide load control similar to what is currently required.

377. If ARC provides load control similar to its current requirement, its rate will increase by 9.32%.

378. The initially proposed Primary General Service rate increase was 12.75%, so the ARC increase is less than the increase applicable to similar C&I customers at primary voltage.

Substation Leases

379. It is unnecessary to require SPS to modify the way it leases substations to customers who take service at transmission voltage because there has been no showing that there is a problem among SPS customers with the current approach.

380. Staff's recommendation to amend SPS's LGS-T tariff and the Electric Service Agreements between SPS and its LGS-T customers is not reasonable given the significant changes required to implement the recommendation.

381. SPS's substation leasing practices are proper and reasonable.

Miscellaneous Preliminary Order Cost Allocation and Rate Design Issues

382. SPS has no existing rate riders that should be modified or terminated, and SPS has proposed no rate riders in this case.

383. The following tariff revisions proposed by SPS are uncontested, are reasonable, and are approved:

- Establishment of experimental TOU rates for customers in the Residential Service, Small General Service, Secondary General Service, Primary General Service, Small Municipal and School Service, Large Municipal Service, and Large School Service classes;

- Establishment of Tariff Sheet No. IV-206, which is a Low Load Factor tariff, for the Secondary General Service and Primary General Service classes;

- Amendment of Tariff Sheet No. IV-56 to delete Chase Bank as a customer listed under the tariff. The outdoor lighting for Chase Bank has been updated, and it no longer requires a service agreement because the lighting can be billed under other generally applicable lighting rates;

- Elimination of Tariff Sheet No. IV-58 because Cal Farley's Boys Ranch no longer takes service under the tariff;

- Revision of Tariff Sheet No. IV-99 to correct references to the company listed in the tariff from "Degussa" to "Orion Engineered Carbons" to reflect the customer's change in name;

- Revision of the Distributed Generation Interconnection tariff to avoid duplication of information. Presently, both the Distributed Generation Interconnection tariff (IV-159) and the Secondary Standby Service tariff (IV-180) provide rates for Secondary Standby Service. SPS proposes to remove the rate information from the Distributed Generation Interconnection tariff and to refer to the Secondary Standby Service tariff for rate information. SPS is also proposing to delete a reference to a discount for service at primary voltage because SPS also offers Primary Standby Service;

- Revision of the applicability section of Small Municipal and School Service and Large School Service tariffs to add language clarifying that the tariffs apply only to K-12 schools, whether public or private;

- Revision of Tariff Sheet Nos. IV-179, IV-180, IV-181, and IV-183 to clarify that, for customers that have power factor metering, the power factor charge will apply. SPS further proposes the addition of a power factor provision to applicable customers with 200 kW loads or greater; and

- Revision of Tariff Sheet Nos. IV-18, IV-108, IV-173, IV-175, IV-179, IV-180, IV-181, IV-182, and IV-183 to change billing for power factors below 90% from kVAR-based to kW-based. The 90% power factor allows a 5% grace level before the revised power factor charges are applied. The revised power factor charges ensure a ratio of 95% power factor to metered power factor multiplied by metered kW and the applicable kW charge.

Procedures and Model for Number Runs and Compliance Tariff

384. The Management Applications Consultants, Inc. is a reasonable tool to use for allocating costs among classes.

VII. Conclusions of Law

1. SPS is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission has jurisdiction over this matter under PURA §§ 14.001, 36.001-36.111, 36.203-36.205, 36.209, and 36.210, and 16 TAC §§ 25.231, 25.238, 25.239, 25.243, and 25.245.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket pursuant to PURA § 14.053 and Tex. Gov't Code Ann. § 2003.049 (West 2008 & Supp. 2014) (APA).

4. This docket was processed in accordance with the requirements of applicable law, including PURA and the Texas Administrative Procedure Act, TEX. GOV'T CODE ANN. Chapter 2001, and the Commission's procedural rules.

5. SPS provided notice of its application in accordance with PURA § 36.103 and 16 TAC §§ 22.51(a) and 25.235(b).

6. Pursuant to PURA § 33.001, each municipality in SPS's service area that has not ceded jurisdiction to the Commission has jurisdiction over SPS's application.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. SPS has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, SPS's overall revenues approved in this proceeding permit SPS a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to SPS in providing service.

11. SPS's proposed post-test year adjustments to rate base violate 16 TAC § 25.231(c)(2)(F)(i)(II) and (ii)(I), and SPS did not show good cause to make an exception to those rule requirements.

12. The ADIT adjustments approved in this proceeding are consistent with PURA § 36.059 and 16 TAC § 25.231(c)(2)(C)(i).

13. Including the cash working capital approved in this proceedings in SPS's rate base is consistent with 16 TAC § 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

14. The return on equity and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

15. 16 TAC § 25.231(b) provides that in computing a utility's reasonable and necessary operating expenses, the Commission should consider historical test year expenses as adjusted for known and measurable changes.

16. PURA § 36.065(b) allows a utility to establish a reserve account to record the difference between the amount of pension and OPEB expense approved in the utility's last general rate case and the annual amount of pension and OPEB expense that the utility actually bears.

17. 16 TAC § 25.231(b)(1)(b) provides that depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission shall be used, but other methods may be used when the Commission determines that such depreciation methodology is a more reasonable means of recovering the costs of plant.

18. The reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

19. The affiliate expenses approved in this proceeding and included in SPS's rates meet the affiliate payment standards articulated in PURA §§ 36.051 and 36.058 and in *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W. 2d 783 (Tex. App.—Austin 1984, no writ).

20. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not demonstrate good cause to make an exception to that rule.

VIII. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following Order:

1. The proposal for decision is adopted to the extent consistent with this Order.

2. SPS's application is granted to the extent consistent with this Order.

3. The findings of fact and conclusions of law in this order are binding, irrespective of whether an ordering paragraph explicitly addresses the same subject.

4. SPS is authorized to file an application to implement a surcharge to recover the revenue it would have received for service rendered on and after June 11, 2015, through the date the rates set in this case take effect.

5. SPS shall file in Tariff Control No. 45442, *Compliance Tariff for Final Order in Docket No. 43695 (Application of Southwestern Public Service Company for Authority to Change Rates*) tariffs consistent with this Order within 20 days of the date of this Order. No later than 10 days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

6. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, SPS shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

7. Copies of all tariff-related filings shall be served on all parties of record.

8. SPS shall investigate (including work with affiliates regarding their charges) and detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M expenses, steps being taken to reduce them, and the timing and cost impact of those steps.

9. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the ______ day of December 2015.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, CHAIRMAN

KENNETH W. ANDERSON, JR., COMMISSIONER

BRANDY MARTY MARQUEZ, COMMISSIONER

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PUC DOCKET NO. 43695
SOAH DOCKET NO. 473-15-1556

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	§ § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER ON REHEARING

This order addresses the application of Southwestern Public Service Company (SPS) for authority to change its Texas retail rates, filed on December 8, 2014. SPS originally sought a $64.75 million increase to its Texas retail revenue requirement. SPS subsequently reduced its requested increase to $58.85 million and then further lowered its request to a $42.07 million increase.[1]

A hearing on the merits was held over seven days at the State Office of Administrative Hearings (SOAH). On October 12, 2015, the SOAH administrative law judges (ALJs) filed their proposal for decision (PFD) in which they recommended a Texas retail revenue requirement increase of $1.2 million. In response to parties' exceptions and replies to the PFD, on November 20, 2015, the SOAH ALJs filed a letter making changes to the PFD, including clarifying that they were recommending a $14.4 million increase to SPS's Texas retail revenue requirement.

Except as discussed in this order, the Commission adopts the PFD as modified, including findings of fact and conclusions of law. The Commission's decisions result in a Texas retail base-rate revenue requirement of $509,395,343, which is a decrease of $4,025,973 from SPS's present Commission-authorized Texas retail base-rate revenue requirement. Finding of Fact 237A is modified to reflect the Commission-authorized decrease to SPS's Texas retail revenue requirement. New findings of fact 19A through 19K are added to reflect issuance of the PFD and filings and events thereafter. The Commission incorporates by reference the abbreviations table provided in the PFD.

[1] Southwestern Public Service Co. (SPS) Initial Brief on the Revenue Requirement (Rev.) at 17 (Jul. 24, 2015); Proposal for Decision (PFD) at 27 (Oct. 12, 2015).

I. Golden Spread Adjustment to Jurisdictional Allocation

Under its broad rate-setting authority, the Commission may allow adjustments to a utility's cost of service during a historical test year for changes that are known and measurable.[2] Such an adjustment may be permitted with the intent that the known and measureable change should better represent the utility's cost of service that is apt to prevail in the future.[3] The utility bears the burden of proving that any adjustment it seeks is known and measurable.

In 2012, as part of a 2010 settlement at the Federal Energy Regulatory Commission (FERC), SPS and Golden Spread Electric Cooperative entered into a reduced wholesale power-supply contract. Under the contract, as of June 1, 2015 (11 months after SPS's test year for this proceeding), SPS's annual sale obligation decreased from 500 MW to 300 MW. In addition, SPS anticipates its annual sale obligations will decrease again to 100 MW in 2017, and sales under this contract will cease in 2019.[4]

In its application, SPS proposed an increase above its test-year jurisdictional allocations to Texas retail loads, which increased its Texas retail revenue requirement by $11.1 million, to reflect the June 1, 2015 reduction of its wholesale sales to Golden Spread.[5] The adjustment increased the retail jurisdictions' shares of embedded costs based on the retail jurisdictions' increased share of overall peak demand. The adjustment increased Texas retail's energy allocation factor from 53.77% to 54.90%, and increased Texas retail's production demand factor from 49.94% to 52.41%.[6] SPS asserts the related savings in Texas retail fuel are already being reflected in SPS's fuel rider.[7]

Most parties opposed the proposed change. The SOAH ALJs concluded that this adjustment is appropriate because it reflects a known and measureable change, representing a

[2] 16 Texas Administrative Code Ann. (TAC) § 25.231(a).

[3] "Changes occurring after the test period, if known, may be taken into consideration by the regulatory agency ... in order to make the test-year data as representative as possible of the cost situation that is apt to prevail in the future." *City of El Paso v. Public Utility Commission of Texas*, 883 S.W.2d 179, 188 (Tex. 1994) (quoting *Suburban Util. Corp. v. Public Utility Commission of Texas,* 652 S.W.2d at 358, 366 (Tex. 1983)).

[4] PFD at 8, citing SPS Ex. 6, Evans Dir. T. at 59-61.

[5] PFD at 9, fn 25, citing TIEC Ex. 1, Pollock Dir. T. at 33.

[6] PFD at 9, citing SPS Ex. 54, Luth Dir. T. at 27; TIEC Ex. 1, Pollock Dir. T. at 32-34.

[7] PFD at 9, citing SPS Ex. 38, Evans Rebuttal T. at 40.

change that was known, fixed in time, and measurable. However, the Commission reaches a different conclusion in weighing the evidence and arguments of the parties. The Commission determines that SPS failed to prove its proposed change satisfies all the requirements for a known and measureable change to the utility's test-year data. SPS's proposed adjustment cherry picks one change in the utility's wholesale sales, which occurs after the test year, and fails to show this single change, in the absence of a broader analysis, will better represent the utility's jurisdictional costs and revenues that are apt to prevail in the future. Additionally, SPS's proposed change violates the matching principle because it fails to reflect both SPS's system costs and system sales during the same time period. Instead, SPS's proposed jurisdictional allocations are based on test-year sales and revenues data, except for the post-test-year reduction of sales to one wholesale customer that occurred at a later period. The Commission concludes SPS failed to prove that its mixing of time periods and selective modification relating to one wholesale contract results in a more accurate measure of the utility's jurisdictional costs and revenues that are apt to prevail in the future. The Commission reflects its decision on this jurisdictional-allocation issue by deleting proposed findings of fact 20 through 27 and instead adopting new findings of fact 20A, 21A, 22A, 23A, 24A, 24B, 25A through 25C, 26A, 26B, and 27A.

II. Capital Structure

SPS proposed a capital structure of 46.03% debt and 53.97% equity.[8] SPS's requested capital structure reflected activity through the end of 2014.[9] For example, in July 2014, Xcel invested $60 million to rebalance SPS's capital structure. This additional investment increased SPS's equity and decreased its debt.[10] SPS's proposed capital structure also included projected changes to the equity portion to reflect anticipated retained earnings.[11]

Commission Staff witness Ms. Winker testified that SPS's proposed capital structure is reasonable.[12] Texas Industrial Energy Consumers (TIEC), the Office of Public Utility Counsel

[8] *Id.* at 29; SPS Application at Schedule K-1.

[9] SPS Ex. 8, Schell Dir. at 29.

[10] *Id.* at 29-30.

[11] *Id.* at 30.

[12] PFD at 76, citing Staff Ex. 6A., Winker Dir. T. at 34.

(OPUC), and the United States Department of Energy (DOE) proposed different capital structures with lower portions of equity. TIEC argued the Commission should adopt a 50% debt - 50% equity capital structure.[13] DOE advocated for a capital structure composed of 44.96% long-term debt, 3.06% short-term debt, and 51.98% equity.[14] OPUC asserted an adjustment should be made to SPS's proposal to reflect SPS's actual capital structure on December 31, 2014, instead of what SPS projected its capital structure would be on that same date.[15] OPUC's recommended capital structure also included an adjustment to reflect its recommended treatment of two rate swaps.

In the PFD, the SOAH ALJs recommended SPS's proposed capital structure be adopted.[16] However, the Commission concludes, based on the totality of the evidence, that SPS's rates should be set to reflect a capital structure consisting of 49% debt and 51% equity. This capital structure falls within the range of those supported by record evidence.[17] It is based in part on SPS's test-year capital structure and in part on recent Commission decisions in litigated base-rate proceedings in which the Commission set rates for vertically-integrated electric utilities reflecting capital structures of approximately 50% debt and 50% equity.[18] The Commission-adopted capital structure of 49% debt and 51% equity also reflects what would be a more prudent balance sheet of a vertically-integrated electric utility during this period of low-cost debt.[19] Consistent with this discussion, the Commission rejects proposed finding of fact 72, 74, 75 and 76 and instead adopts findings of fact 72A, 72B, 74A, 75A, and 76A.

[13] TIEC Ex. 4, Gorman Dir. T. at 11-14.

[14] PFD at 78 citing DOE Ex. 1, Reno Dir. T. at 10.

[15] OPUC Ex. 10 at 31, Table 3.

[16] PFD at 80.

[17] PFD at 75-81.

[18] *E.g. Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment,* Docket No. 39896, Order on Rehearing at 18, finding of fact 68 (Nov. 1, 2012) setting rates reflecting a capital structure of 50.05% long-term debt and 49.92% equity; *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing at 31, findings of fact 148 and 149 (Mar. 6, 2014) setting rates reflecting a capital structure of 50.9% long-term debt and 49.1% equity.

[19] *See e.g.* TIEC Ex. 4, Gorman Dir. T. at 13-17 asserting SPS's proposed capital structure unreasonably relies too heavily on equity.

III. Operating and Maintenance Expense

A. Payroll Expense – Annual Incentive Plan

SPS's annual incentive plan is an incentive-compensation plan that covers exempt, non-bargaining employees in all states in which Xcel Energy operates. Each employee eligible to participate in the plan has a set of performance objectives. The amount an employee earns under the plan is dependent upon the achievement of specific corporate, business area, and individual performance goals.[20] In its requested expense for this plan, SPS removed what it asserted were all costs associated with the financially-based performance objectives. However, AXM advocated that all costs of the program should be disallowed as financially-based incentive compensation and OPUC agreed. Alternatively, OPUC's expert calculated a partial reduction to better reflect that the plan has a financially-based trigger and incents each employee to meet financially-based performance goals. Commission Staff also calculated its own recommended disallowance, reflecting what Commission Staff deemed to be excessive compensation to Xcel employees categorized as executives or grade X, business-area vice presidents or executives. In the PFD, the SOAH ALJs recommended the Commission accept Commission Staff's recommended reduction and reject the disallowances sought by AXM and OPUC.

It is well-established that a utility may not include in its rates the costs of incentives that are tied to financial-performance measures.[21] The Commission agrees with the SOAH ALJs' characterization of the annual incentive plan as "complicated" and notes that when a utility elects to adopt a compensation plan that involves both financially-based and performance-based metrics, the utility still must show it has removed all aspects of the financially-based goals from its requested expense.[22] Based on the testimony of the experts offered by AXM and OPUC, the Commission is not convinced SPS's adjustment fully captured the financial aspects of the annual incentive plan. Yet, SPS has sufficiently demonstrated that some portion of the plan is tied to performance-based objectives and is part of the necessary expense of attracting and retaining

[20] SPS Ex. 29, Reed Dir. T. at 26-27.

[21] *E.g. Application of Entergy Texas, Inc. for Rate Case Expenses Pertaining to PUC Docket No. 39896*, Docket No. 40295, Order at 2 (May 21, 2013) "The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services."

[22] PFD at 86.

qualified Xcel employees. Therefore, removing all the expense of the plan would likewise be improper. Ultimately, the Commission adopts the amount of plan expense that OPUC recommended as an alternative. This amount better reflects that the plan has a financially-based, earnings-per-share trigger and requires Xcel employees to meet metrics that include financial goals, in addition to performance-related goals. Accordingly, the Commission deletes proposed findings of fact 83 through 85 and instead adopts new findings of fact 83A, 83B, 84A, and 85A.

B. Pension and Related Benefits – Stock-Equivalent Plan

Xcel Energy has a stock-equivalent plan that it provides to non-employee members of its board of directors. In its application, SPS included $163,701 as SPS's allocated expense of this plan. OPUC challenged this expense. In the PFD, the SOAH ALJs recommended the plan's expense should be removed, stating they are not persuaded the expense is a necessary component of SPS's cost of providing electric service.[23]

The Commission agrees that the expense associated with Excel Energy's stock-equivalent plan may not be included in SPS's reasonable and necessary expense; however, the Commission reaches this conclusion based upon different analysis.

SPS proved Xcel Energy is legally required to have a board of directors.[24] Further, such directors must be adequately compensated. Therefore, SPS's share of the compensation paid to Excel Energy's unaffiliated directors could be reasonable and necessary if properly structured and shown to be an reasonable amount. However, in this proceeding, SPS failed to prove the stock-equivalent plan is not financially-based incentive compensation. Each unit that sets director compensation under the plan has a value equal to one share of Xcel stock, directly aligning the non-employee directors' interests with shareholders'.[25] Thus, consistent with its decision in numerous prior base-rate proceedings, the Commission rejects the utility's requested expense. To reflect this decision, the Commission deletes proposed findings of fact 102. Instead, the Commission adopts new findings of fact 102A through 102D.

[23] PFD at 104.

[24] SPS Ex. 48, Reed Rebuttal T. at 28. Ms. Reed cites to Section 302A.201, Subd. 1, Minnesota Statutes.

[25] OPUC Replies to Exceptions at 16.

C. Depreciation Expense – Accounts 392.02 and 392.04

In its application, SPS calculated its depreciation expense using average service lives of 10 years for light trucks and vans (entered in Federal Energy Regulatory Commission Uniform System of Accounts number 392.02) and 12 years for heavy trucks (entered in FERC account number 392.04). In the PFD, the SOAH ALJs recommended that the Commission instead adopt the respective average service lives of 12 and 14 years, as advocated by AXM.

The Commission overturns this portion of the PFD and instead determines the appropriate average service lives are 10 years for items in FERC account number 39.202 and 12 years for items in FERC account number 39.204. The SOAH ALJs' recommendation was based in part on notes from SPS's most-recent prior rate case, Docket No. 42004. However, those notes in fact reflected ranges of average service lives that were consistent with SPS's request in this proceeding. Further, SPS demonstrated in its rebuttal testimony that its proposal is based on a thorough actuarial analysis that includes estimates from JJ Kane, an auction house for used utility equipment. AXM's witness also conducted an actuarial analysis, but used data from the National Automobile Dealers' Association that represents the interests of new car & truck dealers and manufacturers.[26] The Commission deletes proposed findings of fact 124, 127, and 128, and adopts new findings of fact 124A, 127A, and 128A.

D. Affiliate Charges - Charges to Work Orders with New Mexico in the Titles

Xcel Energy Services, Inc. (XES), is a service company affiliated with SPS. Some of the work orders for which XES billed SPS during the test year included New Mexico or New Mexico locations in the work orders' titles. Other work orders included Texas or Texas locations in their titles. SPS applied a jurisdictional allocator to the work orders with Texas- or New Mexico-related titles and sought to include in its affiliate expense the Texas retail portion of these work orders. OPUC opposed including the charges for the work orders with New Mexico-related titles. In the PFD, the SOAH ALJs recommended that SPS met its initial burden of providing evidence that the contested work orders were allocated properly to the appropriate jurisdictions. However, the SOAH ALJs further concluded that, after OPUC raised a concern regarding these work orders, SPS failed to adequately explain in detail why the titles of the work orders are not assigned solely

[26] SPS Ex. 44, Watson Rebuttal T. at 79-82.

to the jurisdiction in the title. Thus, the ALJs recommended a disallowance of $203,474 associated with these work orders.[27]

The Commission acknowledges SPS's rebuttal testimony on this issue could have been more robust, but is persuaded by SPS's argument that it would be inconsistent and unfair to include only a portion of the costs of work orders with Texas-related titles while also excluding the costs of work orders with New Mexico-related titles. SPS provided evidence that the name of the state in a work order title does not mean that the associated work was performed only for the benefit of customers in that state. Rather, SPS witness, Ms. Schmidt-Petree, explained the relevant orders are associated with managerial-level work.[28] And other SPS witnesses attested to the reasonableness and necessity of the costs for the relevant XES work orders and the benefits to SPS's Texas customers.[29] Therefore, the Commission concludes SPS met its burden to show the reasonableness and necessity of the Texas-jurisdictional portion of the XES work orders with New Mexico-related titles. The Commission declines to adopt the SOAH ALJ's recommended disallowance, deletes finding of fact 136, and adopts modified findings of fact 136A through 136D to reflect the Commission's decision on this affiliate-expense issue.

E. Renewable Energy Credit Sales Revenue

Currently, SPS's revenues from sales of its renewable-energy credits (RECs) are credited to SPS's eligible fuel expense that is collected in a rider separate from the utility's base rates. Commission Staff recommended that SPS's revenues from REC sales instead be included in calculating the utility's base rates. SPS opposed both Commission Staff's proposal and Commission Staff's calculation of the utility's REC revenues.

In the PFD, the SOAH ALJs agreed with Commission Staff's recommendation to include REC revenues in base rates, but concluded the Commission should use SPS's calculation of those revenues.

[27] PFD at 153-156.

[28] SPS Ex. 45, Schmidt-Petree Rebuttal T. at 8.

[29] *See* SPS's Exceptions to the PFD at 65, citing SPS testimony.

The Commission adopts the SOAH ALJ's recommendation that SPS's revenues from sales of its RECs should be included in setting the utility's base rates. However, the Commission adopts Commission Staff's calculation of those revenues, instead of SPS's calculation. Commission Staff's calculation better reflects SPS's reasonable REC revenues because it recognizes that all of SPS's excess RECs obtained during the test year would eventually be sold by a prudent utility. Further, SPS failed to prove why it would be reasonable for SPS to purchase and then, sometimes years later, sell at a loss RECs in excess of those required to meet Texas's renewable portfolio standard requirements. Commission Staff's calculation is consistent with the ALJ's recommended imputed price for bundled RECs, and use of this same amount for REC sales revenue will remove any increase in REC costs associated with selling the excess RECs at a loss. Consistent with its decision on this subject, the Commission deletes proposed findings of fact 198 and adopts new findings of fact 198A through 198C.

IV. Inter-class Cost Allocation and Revenue Distribution

A. Gradualism Adjustment

SPS requested rates based on a recent inter-class cost-of-service study (COS study), but with a two-step modification to result in the maximum base-revenue increase for any class being capped at 200% of the system-average increase and no class experiencing a rate decrease.[30] TIEC and Occidental Permian, Ltd. recommended a 150% average-system-wide-increase cap with no class experiencing an increase smaller than 50% of the system-average increase. AXM advocated for a 175% average-system-increase cap. DOE, OPUC, and Walmart supported a gradualism adjustment, depending on the final SPS revenue requirement and the impacts to each rate class.[31] Staff and Pioneer opposed any gradualism adjustment, asserting no customer class's rates would be modified enough to create rate shock. Thus, Staff and Pioneer argued, there is no justification for veering from the Commission's long-standing guiding principle that costs should be borne by the classes who cause them.

[30] SPS Ex. 54, Luth Dir. T. at 60.

[31] PFD at 271.

In the PFD, the SOAH ALJs concluded that the Commission should adopt rates consistent with SPS's proposed gradualism adjustment.[32] The SOAH ALJs stated their recommendation struck a balance between competing policies and was consistent with recent Commission decisions in Dockets No. 39896 and 40443.[33]

The Commission declines to adopt any gradualism adjustment in this proceeding. The Commission has often stated that one of its primary responsibilities in setting rates is ensuring those rates are, to the greatest extent reasonable, consistent with cost causation. Further, as SPS conceded, the wisdom of a gradualism adjustment is affected by the size of the rate change.[34] While there is no magic threshold at which a change in rates automatically justifies an aberration from basing rates on classes' costs of service, in Docket 40443, the Commission determined that an increase as large as 29% did not warrant rate mitigation.[35] Here, SPS's overall Texas retail revenue requirement will be decreased by less than 1% and class allocations based purely on each classes' cost of service will result in relatively small rate changes. All but one class will experience less than a 14% change to its base-revenue responsibilities. The largest change will be borne by Street Lighting customers, whose revenue responsibility will increase 24.28%.[36] Thus, moving from classes' costs of service and mandating inter-class cost subsidization is not warranted in this proceeding. Consistent with the Commission's decision to not include any adjustments for gradualism, the Commission deletes proposed findings of fact 335 through 337 and instead adopts new findings of fact 335A through 335C, 336A, and 337A through 337C.

B. Calculation of System Load Factor

SPS calculated its system load factor, used to weight the average demand for the SPS system, by averaging the coincident peaks at the time of the SPS system peaks for the months of

[32] *Id.* at 280.

[33] *Id.* at 281.

[34] SPS Reply to Exceptions at 131.

[35] Staff Ex. 1A Murphy Direct T. at 53 (discussing rate changes adopted in Docket No. 40443); Docket No 40443, Proposal for Decision at 269 (May 20, 2013) adopted without modification by the Commission in its Order on Rehearing (Mar. 6, 2014).

[36] Commission Staff memorandum dated December 11, 2015 at 20, Attachment C.

June, July, August, and September, adjusted for losses (4CP).[37] Commission Staff, TIEC, State Agencies, and Occidental contested SPS's calculation. Those opposing SPS's calculation argued that SPS's system load factor should instead be based on the single highest peak demand measured during the test year, adjusted for losses (1CP).

In the PFD, the SOAH ALJs recommended that the Commission adopt SPS's proposal to use a 4CP-system-load factor. The SOAH ALJs noted 4CP was used when setting rates for Southwestern Public Service Company (SWEPCO) in Docket No. 40443. The SOAH ALJs also concluded that parties advocating for a 1CP load factor did not establish how 1CP will result in more proper cost allocation.[38] The Commission, however, is persuaded by the evidence of those parties, including TIEC, that assert use of a 1CP factor is more consistent with how SPP plans transmission and how SPS plans and builds its generation and transmission systems.[39] Further, in deposition, SPS's witness Mr. Luth acknowledged that a 1CP load factor is reasonable.[40] To reflect its decision of this issue, the Commission deletes proposed findings of fact 246 through 256 and instead adopts new findings of fact 246A through 251A.

C. Allocation of Radial Transmission Lines

In its application, SPS allocated the costs of its looped transmission lines to all classes based on each class's total contribution to the Texas retail average-and-excess-demand four coincident peaks (AED-4CP). For radial transmission lines, SPS made two proposals: direct assignment of the costs of radial transmission lines used to serve a single customer class and use of the AED-4CP allocation method for the costs of radial transmission lines that provide service to more than one customer class.[41] Numerous parties opposed SPS's proposed allocations regarding its radial transmission lines. TIEC, Occidental, DOE, and Amarillo Recycling Company asserted that, consistent with prior practice, the cost of an SPS radial transmission line should be allocated only to those classes that receive service from the line. In contrast, Commission Staff and OPUC advocated that all of SPS's transmission lines, including the radial transmission lines,

[37] SPS Ex. 61, Evans rebuttal at 18.

[38] PFD at 226-228.

[39] TIEC Ex. 2, Pollock Dir. T. at 27; State Agencies Ex. 1, Pevoto Dir. T. at 8-9.

[40] TIEC Ex. 65, Luth Deposition at 67.

[41] SPS Ex. 61, Evans Rebuttal T. at 26.

should be allocated among SPS's classes in proportion to AED-4CP transmission demands without regard to looping or the location of class loads.[42]

In the PFD, the SOAH ALJs concluded basic cost-causation principles favor allocating the costs of SPS's multi-class radial transmission lines solely to the classes that take service from those lines.[43]

While the Commission appreciates the SOAH ALJs' mindfulness of the importance of cost-causation, the Commission reaches a different conclusion in addressing this issue. The Commission is persuaded by Commission Staff's arguments and concludes that all of SPS's transmission lines, including radial transmission lines, should be allocated to all classes in the same manner, using SPS's AED-4CP allocation method. Commission Staff showed that direct allocation of radial lines would be inconsistent with the manner in which transmission costs have traditionally been allocated in Texas. For example, in the Electric Reliability Council of Texas (ERCOT) footprint, the costs of transmission infrastructure are generally pooled and allocated system wide. Further, the Commission is persuaded by SPS that the utility lacks sufficient load data to more fairly allocate the costs of those transmission lines that are known to serve more than one customer class. The Commission reflects its decision on this class-allocation issue by deleting proposed findings of fact 257 through 265 and instead adopting new findings of fact 257A, 258A, 259A, and 260A.

D. Allocation of Primary and Secondary Distribution Costs within the Residential Class

SPS proposed to allocate distribution costs separately among its general-residential-service customers and those residential-service customers who take service under the rates for residential customers with electric space heating, based upon each group's non-coincident peak (NCP) distribution load. OPUC challenged this cost allocation, asserting distribution costs should instead be allocated to the residential class as a whole, based on the highest load of the entire residential class. In the PFD, the SOAH ALJs recommended the Commission deny OPUC's proposal and instead accept SPS's proposal to allocate distribution costs separately to each residential subclass based on each subclass's own NCP distribution load.

[42] Staff Ex. 1A, Murphy Direct T. at 44-46.

[43] PFD at 235.

The Commission overturns this portion of the PFD because the Commission is persuaded by OPUC's arguments that costs should be allocated to the Residential class as a whole, reflecting it is a single customer class. Therefore, the Commission deletes proposed finding of fact 277 and instead adopts new findings of fact 277A and 277B.

E. Allocation of Meter-reading Costs

SPS proposed in its application to modify its prior method for allocating among its classes the costs of meter reading. SPS's new proposal involved applying a weighted count of the number of meters that can be read in a day for each class.[44] Although challenged by TIEC and State Agencies, the SOAH ALJs concluded SPS met its *prima facie* burden to show this proposed allocation method is reasonable and should be adopted.

The Commission is persuaded by State Agencies and TIEC that SPS failed to meet its burden of proof. SPS's proposal is not based on a formal study and fails to recognize that many factors may affect the respective costs of reading meters of customers in a particular class. For example, SPS witness Mr. Luth agreed during deposition that some of the industrial and large commercial customers have interval data recorder meters that do not require physical meter reading.[45] Therefore, the Commission adopts rates reflecting SPS's previous method of allocating the costs of meter reading based on customer count. The Commission deletes proposed findings of fact 307 through 309 and instead adopts new findings of fact 307A, 308A, and 309A.

V. Rate Design

A. Approval of Rate Classes in this Proceeding

The Commission's electric rule, 16 TAC § 25.5, defines the terms "customer class" and "rate class."[46] A customer class is defined as, "A group of customers with similar electric service characteristics (e.g., residential, commercial, industrial, sales for resale) taking service under one

[44] SPS Ex. 54, Luth Direct T. at 56.

[45] PFD at 250 citing TIEC Ex. 65, Luth Deposition at 83.

[46] 16 TAC § 25.5(23), (100).

or more rate schedules. . . ."[47] A rate class is defined as, "A group of customers taking electric service under the same rate schedule."[48]

Commission Staff requested that the Commission make explicit in its final order what SPS rate classes are approved in this proceeding. Doing so would reduce or eliminate uncertainty in other types of rate proceedings, such as future energy-efficiency-cost-recovery factors, saving rate-case expenses.[49] SPS responded that the Commission should approve as rate classes the 11 customer classes proposed by SPS; however, the Commission should not identify other rate classes. SPS also asserted it should not be precluded from requesting different rate classes in future base rates proceedings.[50]

In the PFD, the SOAH ALJs recommended approval of 12 rate classes in this proceeding. They further recommend that it is not appropriate to determine requirements or parameters regarding rate classes in future base rate proceedings.[51]

The Commission agrees that, to avoid controversy and limit litigation expenses in any future rider proceedings filed before SPS next base-rate case, it is appropriate to explicitly approve the rate classes used in this proceeding. The Commission further concurs that it would be inappropriate to attempt to set parameters or requirements for proposed rate classes in future base-rate proceedings. However, the Commission determines there are 11 rate classes, not 12, as recommended by the SOAH ALJs, because the residential customers who take service under the rates for residential customers with electric space heating are part of the same rate class as the other residential customers. Consistent with this decision, the Commission adopts new finding of fact 339A.

[47] 16 TAC § 25.5(23).

[48] 16 TAC § 25.5(100).

[49] PFD at 282-283 citing Staff Ex. 1A, Murphy Dir. T. at 57.

[50] SPS Ex. 57, Luth Rebuttal T. at 59, SPS Reply to Exceptions at 132

[51] PFD at 285.

B. Residential Service with Electric Space Heating Winter Rate

In its application, SPS proposed to delete its tariff for residential service with electric space heating.[52] SPS also requested to place residential service with electric space heating as a separate rate on its general residential service tariff, close this service to new customers, and increase the discount (*i.e.* lower the rate) of the off-peak, winter energy charge assessed on customers who will take service under the rider for residential customers with electric space heating.[53] In the PFD, the SOAH ALJs recommended that the Commission adopt SPS's proposals, including increasing by 0.5 cents per kilowatt hour (kWh) the winter discount for customers taking service under residential service with electric space heating rider.[54]

The Commission agrees with SPS and the SOAH ALJs that it is appropriate to increase the winter discount for customers taking service under residential service with electric space heating rider; no party refuted SPS's evidence that this group of customers has a higher load factor in the winter months and therefore their winter kWh rate can be lower than the winter kWh rate for general residential customers.[55] In fact, eliminating or reducing the difference in the winter energy charges between the general residential service group and the residential service with electric space heating group would move both away from cost-based rates.[56] While the Commission adopts the SOAH ALJs' recommendation, in response to motions for rehearing and replies thereof, the Commission corrects finding of fact 346 to reflect that, as a result of the totality of the Commissions' decisions, the difference in the winter discount is no longer 0.5 cents per kWh.

The Commission also makes corrections to findings of fact 235, 338, 340, 342, 359, and 383 and ordering paragraph 4. Further, for clarity and consistency, the Commission makes additional, non-substantive revisions to proposed findings of fact and conclusions of law. The Commission also adopts new ordering paragraph 3 to make explicit that its findings of fact and conclusions of law are binding, irrespective of whether an ordering paragraph explicitly addresses the same subject.

[52] SPS Ex. 54, Luth Direct T. at 74.

[53] *Id.*; SPS Ex. 57, Luth Rebuttal T. at 50.

[54] PFD at 288-289.

[55] SPS Ex. 57, Luth Rebuttal T. at 50.

[56] *Id.*

The Public Utility Commission of Texas (Commission) adopts the following findings of fact and conclusions of law:

VI. Findings of Fact

Procedural History

1. Southwestern Public Service Company (SPS) is an investor-owned electric utility with a retail service area located in Texas.

2. SPS serves retail and wholesale electric customers in Texas and New Mexico. The New Mexico Public Regulation Commission regulates SPS's New Mexico retail operations. The Federal Energy Regulatory Commission (FERC) regulates SPS's wholesale electric operations.

3. On December 8, 2014, SPS filed with the Public Utility Commission of Texas (Commission) an application requesting approval of an increase in base-rate charges for the Texas retail jurisdiction of $64,746,197. SPS also requested approval of a set of proposed tariff schedules reflecting the increased rates and other revised terms.

4. The 12-month test year used in SPS's application runs from July 1, 2013, through June 30, 2014.

5. SPS provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of SPS's Texas service territory. SPS also mailed notice of its proposed rate change to all of its customers. Additionally, SPS timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

6. The following parties were granted intervenor status in this docket: Alliance of Xcel Municipalities (AXM); Amarillo College; Amarillo Recycling Company, Inc. (ARC); Canadian River Municipal Water Authority; Golden Spread Electric Cooperative, Inc.; Laurance Kriegel, an individual residential customer; Occidental Permian, Ltd.; Office of Public Utility Counsel; Pioneer Natural Resources USA, Inc.; state of Texas agencies and institutions of higher education; Texas Cotton Ginners' Association; Texas Industrial

Energy Consumers; United States Department of Energy (DOE); and Wal-Mart Stores Texas, LLC and Sam's East, Inc.

7. On December 9, 2014, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

8. In its initial filing, SPS requested approval of temporary rates to make the rates ultimately set in this case retroactive to January 12, 2015. At the prehearing conference held on December 19, 2014, SPS withdrew that request and agreed to extend the statutory deadline for the Commission's final order from June 11, 2015, to September 30, 2015. In addition, the parties agreed that the final rates set in this case will be made effective retroactive to June 11, 2015, for electric consumption occurring on and after that date.

9. On January 16, 2015, the Commission issued its preliminary order, identifying a non-exhaustive list of 47 issues to be addressed in this proceeding.

10. All of SPS's timely-filed petitions for review of the rate ordinances of the municipalities exercising original jurisdiction within SPS's service territory were consolidated for determination in this proceeding.

11. On March 2, 2015, SPS filed a case update, which reduced its requested base rate increase to $58,852,473.

12. On March 9, 2015, the administrative law judges (ALJs) issued SOAH Order No. 6 severing rate case expense issues that were incurred in connection with this docket into *Review of Rate Case Expenses Incurred by Southwestern Public Service Company and Municipalities in Docket No. 43695*, Docket No. 44498 (pending).

13. On March 30, 2015, the ALJs granted a motion to abate the case for 30 days, and SPS agreed to extend the statutory deadline from September 30, 2015, to October 30, 2015.

14. On April 27, 2015, SPS agreed to extend the statutory deadline to November 20, 2015.

15. On June 10, 2015, SPS filed a rebuttal cost of service, which reduced its requested base rate increase to $42,074,996. That request did not include the rate case expense amounts that had been severed from this proceeding, Docket No. 43695.

16. The hearing on the merits convened on June 24, 2015, and concluded on July 2, 2015.

17. For the revenue requirement phase, initial post-hearing briefs were filed on July 24, 2015, and reply briefs were filed on August 5, 2015. For the cost allocation/rate design phase, initial post-hearing briefs were filed on July 28, 2015, and reply briefs were filed on August 7, 2015.

18. Between July 24, 2015, and August 7, 2015, the parties filed proposed findings of fact, conclusions of law, and ordering paragraphs.

19. On October 7, 2015, SPS agreed to extend the statutory deadline to December 4, 2015.

19A. The SOAH ALJs filed their proposal for decision (PFD) on October 12, 2015.

19B. Parties filed exceptions to the PFD on November 2, 2015.

19C. Parties filed replies to exceptions on November 16, 2015.

19D. The SOAH ALJs filed corrections and modifications to the PFD on November 23, 2015.

19E. At an open meeting of the Commission on December 3, 2015, SPS agreed to extend the procedural deadline to December 18, 2015.

19F. The Commission considered the PFD during open meetings on December 3 and 17, 2015.

19G. On December 18, 2015, the Commission issued an order addressing SPS's application.

19H. On December 30, 2015, Commission Staff filed a motion for rehearing. Motions for rehearing were also separately filed by Mr. Kriegel, AXM, and SPS on January 7, 2016 and OPUC and TIEC on January 11, 2016.

19I. On January 15, 2016, the Commission issued an order, under Texas Government Code § 2001.146(e), extending the time to act on the motions for rehearing to the maximum extent allowed by law. In the same order, the Commission also approved a deadline of January 22, 2016 for parties to file replies to the motions for rehearing, under Texas Government Code § 2001.147.

19J. On January 22, parties filed replies to motions for rehearing.

19K. The Commission considered parties' motions for rehearing and replies to the motions for rehearing during an open meeting on February 11, 2016.

Jurisdictional Allocation

Adjustment for Golden Spread

20. [DELETED]

20 A. SPS's production costs are allocated to its New Mexico, Texas, and wholesale jurisdictions based primarily on two factors: energy (kWh) at source and 12CP production demand (kW) at source.

21. [DELETED]

21A. Based on the historical, test-year usage of customers in SPS's three jurisdictions, Texas retail customers would be allocated 53.77% of SPS's energy-related production costs and 49.94% of demand-related production costs.

22. [DELETED]

22A. SPS proposes a post-test year adjustment to its jurisdictional allocation factors to reflect a 200 MW decrease in wholesale sales to Golden Spread Electric Cooperative (Golden Spread) that SPS stated it expected to occur on June 1, 2015, approximately one year after the end of the test year.

23. [DELETED]

23A. SPS's proposed test year adjustment increases the energy jurisdictional allocator for Texas from 53.77% to 54.90%, and it increases the demand jurisdictional allocator for Texas from 49.94% to 52.41%. The impact of these changes would be to increase Texas's allocation of SPS's production costs by approximately $12 million.

24. [DELETED]

24A. Under the "matching principle," the time period used for expenses must match the time period used for revenues in setting rates.

24B. The Commission has long adhered to the matching principle.

25. [DELETED]

25A. SPS has had load growth in New Mexico since the test year, but has not quantified the amount of that growth for use in this case.

25B. SPS did not offer evidence of its post-test year New Mexico and wholesale jurisdiction sales during the same time period as the reduction in its wholesale sales to Golden Spread.

25C. SPS admits it does not know what the relative loads of its three jurisdictions will be during the rate year.

26. [DELETED]

26A. SPS's failed to prove its proposed post-test-year adjustment to its jurisdictional allocation factors reflects jurisdictional allocations that are apt to prevail in the future.

26B. SPS failed to meet its burden of proving that its proposed adjustment to its jurisdictional allocation factors is known and measurable with reasonable certainty.

27. [DELETED]

27A. SPS's jurisdictional allocation factors should be set based on the actual test-year data.

General and Intangible Plant

28. SPS allocates costs among its Texas retail, New Mexico retail, and wholesale jurisdictions.

29. SPS allocated general and intangible plant for jurisdictional purposes based on the labor excluding administrative and general expense (LABXAG) allocator.

30. The use of the LABXAG allocator is appropriate for allocating general and intangible plant among jurisdictions because the general- and intangible-plant costs are driven primarily by employee needs.

31. The use of the LABXAG allocator is also appropriate to allocate general and intangible plant costs among jurisdictions because SPS uses that allocator to allocate general and intangible plant in its New Mexico retail and wholesale jurisdictions.

Account 923 – Outside Service – Legal

32. SPS allocated FERC Account 923 – Outside Service – Legal costs for jurisdictional purposes based on the LABXAG allocator.

33. The use of the LABXAG allocator is appropriate to allocate outside-service legal costs for jurisdictional purposes because SPS engages outside counsel to perform only the work that

exceeds the capacity of its in-house legal staff, and the costs of the in-house legal staff are allocated based on labor.

Rate Base

Capital Additions as of the End of the Test Year

34. During the period from July 1, 2012, through June 30, 2014, SPS placed the following amounts of plant in service:

a. Production	$204,502,143.67
b. Transmission	$417,911,707.91
c. Distribution	$120,646,272.79
d. General	$ 51,185,115.18
e. Software	$ 21,515,105.63
Total	**$815,760,345.18**

35. Capital additions that were closed to plant in service between July 1, 2012, and June 30, 2014, are used and useful in providing service to the public, and the costs were prudently incurred.

Post Test Year Capital Additions

36. The Commission may approve post-test-year adjustments to plant in service if a utility proves that they meet the requirements of 16 Tex. Admin. Code § 25.231(c)(2)(F) (TAC).

37. In its initial filing, SPS requested post-test-year adjustments to include in rate base a total of $441,651,953 (total company) for numerous capital additions to be placed in service between July 1, 2014, and December 31, 2014. On March 2, 2015, SPS updated that amount to reflect actual expenditures of $392,549,024.39.

37A. Changes in SPS's post-test-year-adjustment proposal account for most of the large post-application reduction in SPS's requested Texas retail base rate revenue increase. Those changes are shown below:

Timing of SPS's Requested Base Rate Revenue Increase	Base Rate Revenue Increase	Base Rate Revenue Increase from Proposed Post-Test-Year Adjustments
December 2014 (application)	$64.75 million	$29.7 million

March 2015 (case update)	\$58.85 million	\$23.8 million
June 2015 (rebuttal case)	\$42.07 million	\$8.9 million

38. None of the capital additions for which SPS sought a post-test-year adjustment satisfies the requirement in 16 TAC § 25.231(c)(2)(F)(i)(II) that each addition comprise at least 10% of SPS's requested rate base, exclusive of the post-test-year adjustments and construction work in progress (CWIP).

39. SPS's proposed post-test-year adjustments to rate base do not satisfy the requirement in 16 TAC § 25.231(c)(2)(F)(ii)(I) that each post-test year plant adjustment be included in rate base at the reasonable test-year-end CWIP balance.

40. Under 16 TAC § 25.3, the Commission may make good cause exceptions to its rules.

41. SPS requested good cause exceptions to 16 TAC § 25.231(c)(2)(F)(i)(II) and (ii)(I).

42. SPS's asserted basis for the good cause exceptions is the effect the post-test-year adjustments would have on its financial integrity.

43. SPS has investment grade credit ratings and its credit outlook is rated as stable.

44. Even without the post-test-year adjustments to rate base, SPS projects: (1) an earnings before interest, taxes, depreciation, and amortization for year 2015 that is higher than in any year between 2010 and 2014; (2) a funds for operations/debt ratio that is higher than in 2010 and 2013; (3) a funds for operations/interest ratio that is higher than any year between 2010 and 2013; and (4) a better debt/capital ratio than in any year between 2010 and 2014.

45. SPS's requested post-test-year adjustments to rate base are not necessary to its financial integrity, have little effect on SPS's key financial metrics, and are not necessary for SPS to be able to attract capital on reasonable terms.

46. SPS's proposed post-test-year adjustments to rate base should be denied because they violate 16 TAC § 25.231(c)(2)(F)(i)(II) and (ii)(I) and SPS did not show good cause to grant its requested exceptions to those rule requirements.

Depreciation Reserve Balance

47. The depreciation reserve balance approved in this proceeding accurately reflects the depreciation rate approved by the Commission in this proceeding.

48. Software systems that were fully amortized on or before June 30, 2014, when the test year ended, should not be included in rate base.

Prepaid Pension Asset

49. A prepaid pension asset arises under generally accepted accounting principles (GAAP) in accordance with Statement of Financial Accounting Standards (FAS) 87. A prepaid pension asset reflects the amount by which the accumulated contributions to the pension fund exceed the accumulated FAS 87 pension cost.

50. Accounting in accordance with GAAP requires that the amount by which the cash contributions made to the pension trust exceed the accumulated pension cost to be recorded as a prepaid pension asset.

51. Investment income on the prepaid pension asset reduces qualified pension costs calculated under FAS 87, which benefits customers by reducing the amount of pension costs included in base rates.

52. SPS's 13-month prepaid pension asset calculated in accordance with GAAP is $168.6 million (total company), after offsetting a non-qualified pension liability.

53. The prepaid pension asset is appropriately included in rate base because it represents a prepayment by SPS.

54. SPS properly included in rate base the accumulated deferred federal income tax (ADIT) liability associated with the prepaid pension asset.

FAS 106 and FAS 112 Liabilities

55. SPS's 13-month average FAS 106 and FAS 112 liabilities were $17,391,011 (total company) and $2,341,289 (total company), respectively.

56. The FAS 106 and FAS 112 liabilities should be included in rate base because they reflect amounts that customers have funded.

57. SPS properly included in rate base the ADIT assets associated with the FAS 106 and FAS 112 liabilities.

Cash Working Capital

58. Investor-owned utilities may include in rate base a reasonable allowance for cash working capital as determined by a lead-lag study conducted in accordance with 16 TAC § 25.231(c)(2)(B)(iii).

59. Cash working capital represents the amount of working capital, not specifically addressed in other rate base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

60. The lead-lag study conducted by SPS considered the actual operations of SPS, adjusted for known and measurable changes, and is consistent with 16 TAC § 25.231(c)(2)(B)(iii).

61. The cash working capital allowance associated with federal income tax expense was calculated by SPS consistently with the calculations of other negative balances and is proper.

Accumulated Deferred Federal Income Taxes

62. SPS properly included ADIT amounts in rate base, except that the amounts related to the deferred tax assets associated with SPS's bad debt reserve accruals and vacation accrual reserves should not be included in rate base.

63. SPS argued, but did not prove, that the deferred tax assets associated with bad debt reserve accruals and vacation accrual reserves should be included in rate base because the corresponding asset or liability balance recorded on SPS's balance sheet (*i.e.*, the reserve for uncollectible accounts and accrued liability to recognize employee vacations earned but not taken) is included in the cash working capital calculation.

Other Prepayments and Short-Term Assets

64. The following short-term assets should be included in rate base: fuel inventory of $12,255,296; and materials and supplies of $20,289,186 (both total company).

65. The following prepayment amounts (total company) should be included in rate base, in addition to the prepaid pension asset: insurance prepayments of $2,847,487; transmission

prepayments of $172,814; auto licensing prepayments of $56,568; information-technology related prepayments of $119,081; pollution emission prepayments of $422,956; and other benefit prepayments of $9,881.

Regulatory Assets

66. The unamortized amount of deferred pension and Other Post-Employment Benefits (OPEB) costs should be considered a regulatory asset and included in rate base.

67. The capitalized property tax attributable to CWIP that was in service by the end of the test year should be included in rate base.

Rate of Return

68. A return on common equity of 9.70% will allow SPS a reasonable opportunity to earn a reasonable return on its invested capital.

69. A 9.70% return on equity is consistent with SPS's business and regulatory risk.

70. SPS's proposed 5.98% cost of debt is reasonable.

71. It is unreasonable and inconsistent with Commission precedent to include short-term debt in SPS's capital structure.

72. [DELETED]

72A. The appropriate capital structure for SPS is 49% long-term debt and 51% common equity.

72B. A capital structure of 49% debt and 51% equity is based in part on SPS's test-year capital structure, is consistent with recent Commission decisions in other litigated base-rate proceedings for vertically integrated Texas utilities, and reflects a more prudent balance sheet during this period of low-cost debt.

73. The costs incurred by SPS for interest rate swaps were reasonable and prudent. Therefore, no reduction to the cost of debt or the capital structure is warranted.

74. [DELETED]

74A. A capital structure composed of 49% debt and 51% equity is reasonable in light of SPS's business and regulatory risks.

75. [DELETED]

75A. A capital structure composed of 49% debt and 51% equity will be sufficient to attract capital from investors.

76. [DELETED]

76A. SPS's overall rate of return should be set as follows:

Capital Component	Capital Structure	Cost of Capital	Weighted Average Cost of Capital
Long-term Debt	49%	5.98%	2.93%
Common Equity	51%	9.70%	4.95%
Total	100.00%		7.88%

Operation & Maintenance Expenses

77. The final cost of service should reflect changes to the cost of service that affect other components of the revenue requirement, including but not limited to the Texas state gross receipts tax, the local gross receipts tax, and the PUC assessment tax.

Payroll Expense

78. SPS requested the following amounts for payroll expense on a total company basis: $107,840,478 for base salaries; $5,202,078 for Annual Incentive Plan (AIP) payments; $1,343,457 for the Supplemental Incentive Plan (SIP) payments; and $80,138 for the Spot On Award Recognition Program (Spot On) payments.

79. SPS requested an adjustment of 3% to base salary levels of non-bargaining employees to reflect the base salary increases that were scheduled to occur for those employees in March 2015.

80. The 3% base salary increases for non-bargaining employees occurred in March 2015.

81. The salary increases for non-bargaining employees are known because they actually were incurred in March 2015. These salary increases are measurable because the amount has been quantified. Therefore, the known and measurable adjustment to base salary levels for non-bargaining employees is approved and should be reflected in the cost of service.

82. Although SPS requested an adjustment of 3% to base salary levels of bargaining employees to reflect the base salary increases that are likely to result from the current negotiations between SPS and the employees' union, the 3% base salary increases for bargaining

employees is not known and measurable. Therefore, this requested adjustment should be denied.

83. [DELETED]

83A. SPS's Annual Incentive Plan includes both financially-based and performance based goals.

83B. Compensation to employees under the Annual Incentive Plan is based in part on an earnings-per-share trigger.

84. [DELETED]

84A. A certain amount of incentives to achieve operational measures is reasonable and necessary to the provision of electric service. However, SPS failed to prove its proposal removed all the costs associated with the financially-based components of the Annual Incentive Plan.

85. [DELETED]

85A. The Office of Public Utility Counsel's alternatively-recommended adjustment to eliminate $2,604,995 associated with the Annual Incentive Plan, plus corresponding flow through reductions, results in allowable expense for the plan that is reasonable and necessary to the provision of electric service, and should be included in the cost of service.

86. SPS's compensation levels should not be decreased to reflect a post-test-year reduction in the number of SPS and Xcel Energy Services, Inc. (XES) employees because the number of employees is similar to or higher than the test-year number of employees.

87. Because 45% of margins gained from energy trades is allocated to shareholders, and energy traders are eligible for the AIP, SPS's request for recovery of SIP payments to energy traders is unreasonable and not necessary for the provision of electric service. SPS's request for recovery of SIP payments should be denied.

88. SPS's proposed Spot On payments are reasonable and necessary to the provision of electric service, and those expenses should be included in the cost of service.

Pension and Related Benefits

89. SPS requested recovery of $16,202,277 (total company) of qualified pension expenses based on the test year.

90. SPS's actuarially-determined qualified pension expense for calendar year 2014 was $14,308,146 (total company).

91. SPS's actuarially-determined level of qualified pension expense for calendar year 2014 is representative of costs that are likely to prevail during the time rates set in this case are in effect. Therefore, $14,308,146 of qualified pension expense should be included in the cost of service.

92. The $14,308,146 represents the baseline amount for purposes of § 36.065(b) of the Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2007 & Supp. 2014) (PURA) on a going-forward basis for qualified pension expense.

93. SPS requested recovery of $14,354,924 (total company) of active health care expense is based on the test-year amount, adjusted for a 7% escalation rate.

94. SPS's actual active health care expense for calendar year 2014 was $14,117,064 (total company).

95. SPS's actual level of active health and welfare expense for calendar year 2014 is representative of costs that are likely to prevail during the time rates set in this case are in effect. Therefore, $14,117,064 of active health care expense should be included in the cost of service.

96. SPS requested recovery of $250,653 (total company) of test year retiree medical expense calculated in accordance with FAS 87 (also known as OPEB).

97. SPS's actuarially determined retiree medical expense for calendar year 2014 was $173,864 (total company).

98. SPS's actuarially determined level of retiree medical expense for calendar year 2014 is representative of costs that are likely to prevail during the time rates set in this case are in effect. Therefore, $173,864 of active health care expense should be included in the cost of service.

99. The $173,864 represents the baseline amount for purposes of PURA § 36.065(b) on a going-forward basis for retiree medical expense.

100. The following amounts of benefit expense (all total company) are reasonable and should be included in the cost of service: $37,835 for self-insured long-term disability expense calculated in accordance with FAS 112; $1,147,796 for third-party insured workers' compensation expense; $2,668,145 for 401(k) matching expense; and $243,704 for miscellaneous retirement-related costs.

101. SPS requested $163,701 in Stock Equivalent Plan expenses that serve as compensation paid to the Xcel Energy Inc. (Xcel Energy) Board of Directors.

102. [DELETED]

102A. Xcel Energy is required to have a Board of Directors and provides to non-employee members of the Board of Directors compensation with equity shares through a stock equivalent plan.

102B. Each unit that sets director compensation under the stock equivalent plan has a value equal to one share of Xcel stock, directly aligning the non-employee directors' interests with shareholders'.

102C. SPS failed to meet its burden to prove the stock equivalent plan is not financially-based compensation.

102D. SPS's requested expense of $163,701 for the Stock Equivalent Plan expenses should be denied.

103. SPS has withdrawn its request for recovery of $3,565 in Xcel Energy executives' benefits.

104. SPS's requested amount of $634,765 for moving and relocation expenses, as adjusted downward by $37,984, is reasonable and necessary to attract employees.

Deferred Pension and OPEB Expense Recovery

105. SPS is requesting recovery of $3,583,510 of deferred pension and OPEB expense.

106. The amount of deferred pension and OPEB expense is reasonable and should be included in SPS's cost of service.

107. It is appropriate to amortize the deferred pension and OPEB expense over a two-year period.

Depreciation Expense

108. All of SPS's current depreciation rates were set in Commission orders that were based on negotiated settlements and are not precedential.

109. Except as otherwise stated below, SPS's depreciation study recommends appropriate and reasonable depreciation rates for SPS's steam production, other production, transmission, distribution, and general plant.

110. SPS's proposed service lives for production plant are reasonable, and are appropriately used to calculate SPS's production-plant-depreciation rates.

111. None of the parties proposed a net salvage value for production plant that was calculated using a plant-specific study of SPS's production plant.

112. The current positive 5% net salvage value for SPS's Production Plant was set in non-precedential Commission orders that were based on settlements in prior SPS rate cases.

113. The evidence does not support setting a positive net salvage value for SPS's production plant. SPS proved that its production plant has a negative net salvage value.

114. SPS did not propose the negative 8% net salvage value for production plant indicated by the dismantling cost study presented by SPS.

115. The model used in the dismantling cost study was originally developed for decommissioning nuclear plants, and SPS did not prove that the model had been appropriately adapted for use in estimating the cost of dismantling SPS's fossil plants.

116. The dismantling cost study contained a number of assumptions that overstate the net cost of dismantling SPS's fossil plants.

117. In rate cases for various Texas electric utilities, the Commission has approved a variety of net salvage values for production plant, including in many cases a negative 5% net salvage value. SPS proposed a negative 5% net salvage value based on the Commission orders approving a negative 5% net salvage value.

118. SPS did not prove that its Production Plant has a net salvage value of negative 5% or any negative number larger than negative 2%.

119. A negative 2% net salvage value is reasonable and appropriate based on the evidence and should be used for all of SPS's Production Plant.

120. Except for the net salvage value for Transmission Poles & Fixtures (Account 355), SPS's proposed service lives and net salvage values for Transmission Plant are reasonable and should be used to calculate SPS's Transmission Plant depreciation rates.

121. A net salvage value of negative 35% for Transmission Poles & Fixtures (Account 355) is reasonable and should be used to calculate SPS's depreciation rates for that account.

122. The evidence does not show that SPS should be ordered to conduct the study relating to Transmission Poles & Fixtures (Account 355) proposed by AXM.

123. SPS's proposed service lives and net salvage values for Distribution Plant are reasonable and should be used to calculate SPS's Distribution Plant depreciation rates.

124. [DELETED]

124A. SPS's proposed service lives for General Plant are reasonable and should be used to calculate SPS's General Plant depreciation rates.

125. SPS's proposed net salvage values for General Plant are reasonable, and are appropriately used to calculate SPS's General plant depreciation rates.

126. The evidence does not show that SPS should be ordered to conduct the study relating to Miscellaneous Intangible Plant (Account 303) Large Software Systems proposed by AXM.

127. [DELETED]

127A. An average service life of 10 years for Transmission Equipment–Light Trucks (Account 392.02) is reasonable and should be used to calculate SPS's depreciation rates for that account.

128. [DELETED]

128A. An average service life of 12 years for Transmission Equipment–Heavy Trucks (Account 392.04) is reasonable and should be used to calculate SPS's depreciation rates for that account.

Affiliate Charges

129. SPS's affiliates charged SPS $89,746,387 for services during the test year. The vast majority of these operations and maintenance (O&M) expenses – $89,669,175 – were for services rendered by XES. The remaining affiliate services were charged (or credited) to SPS by Northern States Power Company – Minnesota, or Public Service Company of Colorado.

130. After exclusions and pro forma adjustments, SPS sought to recover $86,844,330 in O&M affiliate charges.

131. XES follows a number of processes to ensure that: (1) affiliate charges are reasonable; (2) SPS and other affiliates are charged the same rate for similar services; and (3) the charges approximate the costs incurred by XES to provide the services.

132. The processes followed by XES include: (1) use of service agreements to define the level of service required and the cost of those services; (2) direct billing of affiliate charges when possible; (3) use of reasonable allocation methodologies for charges that cannot be direct billed; (4) billing its services without any mark-up, *i.e.* at cost billing; and (5) use of budgeting processes and controls to control spending.

133. The affiliate charges were grouped into 44 classes.

134. SPS properly removed lobbying costs from the costs of the External Affairs affiliate class. SPS's remaining costs in the External Affairs class, which are 12.5% of the total costs of this affiliate class, are not lobbying costs and are properly recoverable.

135. During the test year, XES incurred legal costs to defend itself against several employment discrimination claims, none of which were found to have merit. The portion of these legal costs allocated to SPS was $79,291 (total company). The employees in question were XES employees; all but one of the claims were asserted solely against XES; and no Xcel Energy operating companies were defendants. The XES employees in question performed jobs that benefited SPS, and it is appropriate that SPS pay its share of the defense costs for these claims.

136. [DELETED]

136A. Affiliate charges totaling $203,474 (total company) were made to SPS using multiple six-digit work orders that contained "New Mexico" or locations within New Mexico in their titles. Six-digit work orders are used to directly charge costs to specific Xcel Energy operating companies, but not to specific retail jurisdictions.

136B. SPS met its burden to prove the managerial-level work associated with these work orders benefitted Texas retail customers.

136C. It would be inconsistent and inequitable to include only a portion of the costs of work orders with Texas in the titles while also wholly excluding the costs of work orders with New Mexico in the title.

136D. The affiliate charges, totaling $203,474 (total company), associated with these work orders are reasonable and necessary expenses and are properly included in setting SPS's base rates.

137. A component of the shared facilities charges SPS incurred from affiliates included the carrying costs associated with those facilities. Because these carrying costs are unnecessary and unreasonable, $1,564,659 should be removed from SPS's affiliate expense. SPS should also make a corresponding decrease to FERC account 922 of $1,187,726 in revenue SPS has received related to carrying costs. This results in a net reduction of $376,933 (total company).

138. SPS agreed to remove $2,475 in Life Event costs, which were contained in multiple affiliate classes, from its application.

139. SPS agreed to remove a $104 charge that was due to a timekeeping entry error from its application.

140. All remaining affiliate transactions for which recovery was sought were reasonable and necessary, were allowable, and were charged to SPS at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged was a reasonable approximation of the cost of providing the service.

Purchased Capacity Costs

141. SPS's capacity-related expenses generally include capacity or demand and non-fuel items, such as O&M expenses or turbine start charges. SPS's capacity-related expenses are reasonable and necessary and are appropriately included in base rates.

142. SPS's proposed changes to purchased power agreement expenses for decreases due to the expiration of purchased power agreements and cost increases based on contractual terms represent appropriate known and measurable adjustments to test-year expenses.

143. Because the term of the second Calpine Energy Services purchased power agreement (Calpine II) extends through May 31, 2019, but the test year only contained one month of Calpine II capacity costs, SPS's adjustment to annualize capacity costs for the Calpine II agreement is an appropriate known and measurable adjustment to test-year expenses.

Coal Procurement Expenses

144. Because SPS's proposed changes to coal procurement costs reflect contractual terms, they represent appropriate known and measurable adjustments to test-year expenses.

145. SPS's coal procurement expenses are reasonable and necessary.

SPP and Other Transmission Charges and Revenue

146. SPS is both a transmission owner and a transmission customer within the Southwest Power Pool (SPP).

147. As a transmission owner, SPS is subject to charges calculated in accordance with the SPP Open Access Transmission Tariff (OATT).

148. Transmission customers within SPP must pay Schedule 11 expenses related to transmission upgrades designated as Base Plan Upgrades.

149. Transmission owners that build base plan upgrades are entitled to receive Schedule 11 revenues from SPP.

150. In the test year, SPS paid $54,595,476 (total company) of Schedule 11 expenses, and it received $60,836,125 (total company) of Schedule 11 revenues.

151. Instead of using its test-year Schedule 11 expenses and revenues to calculate the cost of service, SPS used a calculation based on SPP's October 2014 Revenue Requirement and Rates (RRR) file, adjusted to reflect the return on equity that SPS proposes in this case instead of the return on equity authorized by FERC that underlies the October 2014 RRR file.

152. Using its method described above, and under the assumption that SPS's proposed post-test-year adjustments to rate base are rejected, SPS calculated $77,593,999 (total company) of Schedule 11 expenses and $60,251,331 (total company) of Schedule 11 revenues.

153. SPS proposed that if the Commission adopts a return on equity different from that proposed by SPS, SPS's calculation of the Schedule 11 expenses and revenues be adjusted to use the return on equity the Commission sets in this case.

154. SPP changes its RRR files often. For example, SPP stopped using the October 2014 RRR file when its January 2015 RRR file update took effect, and the RRR file has changed several times since then.

155. Shifts in variables in the RRR file can cause an SPP member's Schedule 11 expenses net of its Schedule 11 revenues to be significantly higher or lower.

156. Under SPS's methodology, SPS's calculated Schedule 11 revenues and expenses would differ substantially depending on the RRR file used. For example, using the October 2014 RRR file would indicate a significant Schedule 11 net expense, and using the January 2015 RRR file would indicate a significant Schedule 11 net credit.

157. The October 2014 RRR file is not a known and measurable change to SPS's test year Schedule 11 revenues and expenses, and using the October 2014 RRR file to calculate SPS's Schedule 11 revenues and expenses would be unreasonable.

158. SPS's cost of service in this case should be determined using SPS's actual Schedule 11 revenues and expenses, which are based on the FERC return on equity that SPP actually used to calculate SPS's Schedule 11 revenues and expenses, not the hypothetical return SPS calculated to account for differences in the returns on equity approved by the Commission and FERC.

159. Differences in regulatory treatment by FERC and the Commission are not limited to setting different returns on equity at a particular time. The rate-setting methodologies used by FERC and the Commission differ in numerous respects.

160. SPS's actual Schedule 11 expenses and revenues for the test year are reasonable and necessary and should be used to calculate SPS's cost of service.

161. Schedule 1-A charges are charges applied to all transmission service under the SPP OATT to cover SPP's expenses related to its administration of the OATT.

162. SPS's test year Schedule 1-A charges were $11,895,856 (total company). SPS removed $3,294,127 attributable to wholesale load and increased the Schedule 1-A expenses by $878,143 (total company) to account for the increase in the Schedule 1-A fee approved by the SPP Board of Directors in October 2014.

163. The adjustment proposed by SPS for Schedule 1-A charges is known because it has already occurred and SPS is currently paying the increased charge. The amount is also measurable because it is calculated on a megawatt-hour basis. The proposed Schedule 1A expense of $9,479,871 (total company) is reasonable and should be included in the cost of service.

164. SPS incurred $8,475,178 of costs during the test year for a transmission reservation across the Lamar Direct Current Tie, a transmission tie between SPS and Public Service Company of Colorado.

165. SPS proposed a known and measurable adjustment of $390,182 to the Lamar Direct Current Tie test-year costs to reflect that Public Service Company of Colorado's FERC-approved formula rate increased on January 1, 2015.

166. The adjustment is known because it has occurred and SPS is currently paying the higher rate approved by FERC. The adjustment is also measurable because it is charged on fixed amount of capacity.

167. SPS's requested amount of $8,865,360 for Lamar Direct Current Tie costs is reasonable and should be included in the cost of service.

168. As a transmission owner within SPP, SPS received transmission revenues from transmission customers for point-to-point service under Schedule 7 and Schedule 8.

169. In the test year, SPS received $4,869,637 of Schedule 7 and Schedule 8 revenues from SPP. SPS proposed to increase the revenues by $457,850 to reflect higher transmission rates approved by FERC.

170. The adjustment is known because the increase in transmission rates has occurred, and it is measurable because it is charged on a megawatt-hour basis.

171. SPS's requested Schedule 7 and Schedule 8 revenue of $5,327,487 is reasonable, and that amount should be included as a revenue credit in the SPS cost of service.

<u>O&M Cost Containment</u>

172. SPS presented a benchmarking study comparing its O&M costs to those of groups of peer utilities.

173. The benchmarking study presented by SPS shows that SPS's overall O&M expenses are reasonable compared to those of peer utilities.

174. SPS's benchmarking study did not include a comparison of O&M expense escalation rates.

175. DOE presented an O&M benchmarking study that compares SPS's administrative and general O&M expenses (A&G expenses) and distribution O&M expenses to those of a peer group of utilities.

176. SPS's and DOE's benchmarking studies were reasonably constructed and are reasonable tools for evaluating SPS's performance at managing O&M expense with respect to the matters analyzed in each study.

177. DOE's benchmarking study indicates that SPS ranks in the bottom or below average quintiles for controlling A&G expense escalation.

178. DOE's benchmarking study indicates that SPS ranks in the bottom or below average quintiles for controlling distribution O&M expense escalation.

179. Based on its benchmarking study, DOE proposed disallowances of $17.2 million (total company) of A&G expense and $3.2 million (total company) of distribution O&M expense.

180. DOE's proposed disallowances would apply the same standard to disallow SPS's A&G and distribution O&M expenses regardless of whether they are affiliate expenses.

181. DOE's benchmarking study analyzed only comparative cost growth rates, not circumstances underlying those growth rates. It did not analyze whether the increase in SPS's A&G and distribution O&M expenses resulted from imprudence.

182. The evidence does not show that the increases in SPS's A&G and distribution O&M expenses resulted from imprudence.

183. SPS presented some evidence of reasons its A&G and distribution O&M expenses have escalated.

184. DOE's proposed adjustments should not be made in this case.

185. DOE's study indicates that further investigation of the substantial escalation of SPS's A&G and distribution O&M expenses is warranted.

186. SPS should be required to investigate (including work with affiliates regarding their charges) and to detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M costs, steps being taken to reduce them, and the timing and cost impact of those steps.

Fleet Fuel Expense

187. Fleet fuel expense reflects the costs that SPS incurs to purchase gasoline and diesel for its fleet of vehicles.

188. SPS's fleet fuel expense during the test year was $5,054,776.

189. Staff proposed to make an adjustment to the test-year level of fleet fuel expense to reflect the reduction in fuel costs since the end of the test year.

190. Staff's proposed adjustment to fleet fuel expense is not known and measurable because fuel prices fluctuate, and it cannot be determined what fuel prices will be during the time the rates set in this case are in effect.

Renewable Energy Credits

191. SPS accrues renewable energy credits (RECs) in connection with purchases of renewable energy.

192. SPS obtains RECs through five long-term purchased power agreements, of which one is unbundled (*i.e.*, the prices of energy and RECs are separately stated) and the other four are bundled.

193. Currently, (1) SPS's revenues from sales of its RECs are a credit to eligible fuel expense; (2) for SPS's bundled purchased power agreements, the imputed value of the RECs is deducted from the total contract price in eligible fuel expense; and (3) SPS's costs for unbundled and bundled RECs are included in base rates.

194. In this case, SPS proposed to continue recovering REC expense in base rates; to continue allowing REC sales revenues to be credited through fuel expense; to continue allowing each state commission to establish the value of RECs generated in that state; to reduce the imputed price of bundled RECs from $1.10 per REC to $0.95 per REC; and to share margins from REC sales on a basis of 90% to customers and 10% to SPS.

195. SPS's proposals to continue recovering REC expense in base rates and to continue allowing each state commission to establish the value of RECs generated in that state are reasonable.

196. A price of $0.64 per bundled REC is reasonable and should be imputed to bundled RECs going forward.

197. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not show good cause to make an exception to that rule. REC sales credits should instead be included in SPS's base rates.

198. [DELETED]

198A. Commission Staff's calculation of a base rate credit of ($444,376), offsetting SPS's REC costs against SPS's REC sales revenues, is reasonable and should be included when setting SPS's base rates.

198B. Commission Staff's calculation reflects that a prudent utility would eventually sell all of its excess RECs.

198C. Commission Staff's calculation is consistent with the imputed price per bundled REC.

199. SPS did not prove that its proposal to allocate margins from REC sales on a basis of 90% to customers and 10% to SPS is reasonable or necessary or would produce any net benefit to customers.

Advertising, Contributions, and Dues

200. The Commission allows recovery for ordinary advertising, contributions, and donations as a cost of service as long as the sum of such items does not exceed three-tenths of 1.0% of the gross receipts for services rendered to the public (a 0.3% cap). 16 TAC § 25.231(b)(1)(e).

201. SPS's total advertising, contributions, and dues expense, without the 0.3% cap, reduced by the ALJs' adjustment of $686,619, is reasonable.

Amortization Expense for Regulatory Assets

202. SPS's proposal to include $1.5 million of historical energy efficiency expense in the cost of service is reasonable and consistent with the Commission's orders in prior SPS base rate cases.

203. SPS's proposal to include $2.8 million of historical REC expense in the cost of service is reasonable and consistent with the Commission's orders in prior rate cases.

204. SPS's proposal to include $34,898 of regulatory meter cost in the cost of service is reasonable.

Rate Case Expenses

205. SPS initially proposed to include in cost of service $2,521,940 of unamortized rate case expenses incurred in two prior SPS dockets, along with the amount of rate case expenses incurred or expected to be incurred in this docket.

206. SPS further proposed to offset those amounts by the remaining unamortized balance of the gain on sale of assets to Lubbock Power & Light, which was $2,226,277, and by the remaining unamortized balance of a credit attributable to the TUCO, Inc. overcharge, which was $83,753.

207. On March 6, 2015, the ALJs severed issues relating to the rate case expenses incurred in this docket and moved them to Docket No. 44498, which left the $2,521,940 of rate case expenses from prior dockets to be addressed in this case.

208. SPS proposed that the Lubbock Power & Light and TUCO, Inc. amounts be offset against the $2,521,940, which leaves a net rate case expense balance of $211,911.

209. It is reasonable to offset the Lubbock Power & Light and TUCO, Inc. amounts against the rate case expenses from prior dockets.

210. The $211,911 is a one-time expense. To avoid possible over-recovery, it should be recovered not through base rates but rather through a rider set to recover that specific amount.

211. Because $211,911 is a relatively small amount and Docket No. 44498 is pending, that amount should be recovered through the rider approved in that docket.

212. Consistent with Commission precedent, SPS should not be allowed to earn a return on unpaid rate case expenses.

213. An opportunity to challenge the reasonableness of SPS recovering the $211,911 was provided in this case. SPS proved that it should recover that amount, and that issue should not be re-litigated in Docket No. 44498.

<u>Miscellaneous Services Revenue</u>

214. SPS's proposal to include approximately $990,000 of miscellaneous services revenue in the cost of service is reasonable and should be approved.

<u>Pole Attachment Fee Revenue</u>

215. SPS included in the cost of service a credit of $1,377,041 to reflect the amount of pole attachment revenues SPS received in the test year.

216. SPS agreed that it is appropriate to increase the pole attachment revenue by $413,379 to reflect a normal amount of pole attachment revenues.

217. It is reasonable to include $1,790,420 of pole attachment revenues in the cost of service.

Interest on Customer Deposits

218. SPS calculated interest using the Commission-approved customer deposit interest rate of 0.09% per annum.

219. Effective January 1, 2015, the Commission-approved customer deposit interest rate fell to 0.07% per annum.

220. It is reasonable to use the updated customer deposit interest rate, which reduces the customer deposit interest balance by $1,627.

Uncollectible Expense

221. SPS requested recovery of $3,910,703 in uncollectible expense based on the test-year amount of uncollectible expense recorded in FERC Account 904.

222. The test-year level of expense is representative of the amount of uncollectible expense that SPS is likely to experience in the future. It is reasonable to include that amount in the cost of service.

Taxes

223. SPS inadvertently omitted the Research and Experimentation credit from the calculation of income tax expense.

224. It is reasonable for the Research and Experimentation credit to be included in the calculation of income tax expense.

225. A Research and Experimentation credit in the amount of $330,071 (total company) should be included in the cost of service.

226. SPS incurs property taxes in each jurisdiction in which it has tangible assets, including production plant, transmission plant, distribution plant, and general plant.

227. SPS made several adjustments to the test year property tax expense, including an adjustment to bring the property balances to June 30, 2014.

228. The property tax expense included in the cost of service should be calculated based on the plant balances as of the end of the test year.

229. It is reasonable to use actual property tax balances from 2014 to determine the ratio of tax to plant balances.

230. Property taxes attributable to CWIP should be capitalized to CWIP rather than charged to the current period operating expense. Capitalizing those property taxes to CWIP is reasonable and in compliance with the FERC Uniform System of Accounts.

231. Total company property tax expense should be calculated by reflecting the actual 2014 property-tax-to-plant ratio applied to the June 30, 2014 plant in service balance, exclusive of CWIP. Thus, the reasonable level of total company property tax expense is $29,723,945.

232. SPS's PUC assessment tax should be removed from FERC Account 928 and reclassified into FERC Account 408, because the PUC assessment tax is a gross receipts tax.

<u>Baselines</u>

233. It is necessary to set baselines for the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor.

234. Consistent with the Commission's initial findings in this proceeding, SPS filed revised calculations of the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor baselines for review and comment by the parties.

235. The baselines set forth in attachment E to this Order reflect the Commission's decisions in this case.

<u>Miscellaneous Preliminary Order Revenue Requirement Issues</u>

236. SPS's requested level of fees for the letter of credit that SPS posts for participation in SPP's transmission congestion rights auction is reasonable.

237. SPS has complied with all requirements of the Commission's final order in *Application of Southwestern Public Service Company for Authorization to Refund Amounts Received from Tri-County Electric Cooperative, Inc. Associated with Docket No. 42004*, Docket No. 44609, Order (Jul. 2, 2015).

237A. SPS should receive a Texas retail base revenue decrease of $4,025,973.

<u>Present Revenue</u>

<u>Weather Normalization Adjustment</u>

238. It is reasonable for SPS to calculate its normal weather based on a 10-year period in order to be consistent with the Commission's decision to use a 10-year period in the most recent SWEPCO base rate case, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Order on Rehearing (Mar. 6, 2014).

239. SPS used weather data in developing its model to calculate the weather normalization adjustment that adequately represented the weather in SPS's service area.

240. The test year heating degree days were 9.7% above normal, the test year cooling degree days were 6.5% above normal, and the test year precipitation was 13.4% below normal.

241. It is reasonable for SPS to adjust its test-year sales for certain customer classes to remove the effects of abnormal weather, and to use its model to calculate the adjustment.

242. It is reasonable for SPS to exclude the test year from the time period used to develop normal weather because including the test year creates a bias in the weather variance analysis.

<u>Annualized Revenue for Transmission-Level Customer 8</u>

243. SPS properly included a known and measurable adjustment, increasing the test year billing determinants to reflect Customer 8's increased usage after the customer installed a second transformer to provide service to additional processes at that customer's facility.

<u>Adjustment to Post-Test Year Billing Determinants</u>

244. SPS properly adjusted the test year billing determinants to reflect known and measurable changes through December 31, 2014.

245. SPS properly matched the billing determinants with the period of post-test year plant adjustments, and it updated the customer class allocation factors to reflect the calendar year 2014 information.

Inter-class Cost Allocation

Demand Allocation

246. [DELETED]

246A. The only aspect of SPS's average-excess-demand coincident-peak calculation that was contested in this proceeding was SPS's calculation of the system load factor by averaging the monthly peak for the four months of June through September, adjusted for loss (4CP).

247. [DELETED]

247A. Commission Staff, TIEC, Occidental, and State Agencies argued SPS should have instead based its system load factor on the single highest system peak, adjusted for loss (1CP).

248. [DELETED]

248A. Commission Staff stated that use of 1CP to calculate the system load factor best reflects cost causation because SPS uses the single system peak for resource planning.

249. [DELETED]

249A. TIEC cited to the Southwest Power Pool's requirement that its members have capacity margins based on 1CP.

250. [DELETED]

250A. SPS's witness, Mr. Luth, conceded that use of a 1CP system load factor is reasonable.

251. [DELETED]

251A. SPS's system load factor used for allocating demand should be based on 1CP.

252. [DELETED]

253. [DELETED]

254. [DELETED]

255. [DELETED]

256. [DELETED]

Radial Lines

257. [DELETED]

257A. For transmission-facility costs other than radial lines, SPS has traditionally allocated the costs among all customer classes using the DTRAN allocator.

258. [DELETED]

258A. SPS did not have adequate load research data for the individual customers on radial lines to determine what contributions they make to system peaks.

259. [DELETED]

259A. Direct allocation of the costs of radial transmission lines would be inconsistent with the manner in which transmission costs have traditionally been allocated in Texas. For example, in the Electric Reliability Council of Texas (ERCOT) footprint, the costs of transmission infrastructure are generally pooled and allocated system wide.

260. [DELETED]

260A. It is reasonable to allocate the costs of SPS's transmission facilities, including radial lines, to all classes using SPS's DTRAN allocator.

261. [DELETED]

262. [DELETED]

263. [DELETED]

264. [DELETED]

265. [DELETED]

General Plant and Intangible Plant

266. It is reasonable to allocate General and Intangible Plant (G&I Plant) costs among classes primarily on the basis of Salaries and Wages Excluding Administrative & General (SALWAGXAG).

267. The use of a labor allocator, such as SALWAGXAG, is consistent with cost-causation principles because G&I Plant costs are driven largely by the needs of employees.

268. The National Association of Regulatory Utility Commissioners Cost Allocation Manual contemplates the use of a labor allocator for G&I Plant costs.

269. The Commission's rate filing package for transmission and distribution utilities is not a rule and does not apply to vertically integrated utilities such as SPS.

270. Because G&I Plant is driven primarily by labor, SPS appropriately used the SALWAGXAG allocator to allocate those costs among the classes.

Miscellaneous Revenue

271. It is reasonable to allocate revenue from miscellaneous service charges and returned check fees based on the distribution plant in service allocator because the charges originate from customers that take service at distribution voltage.

272. SPS's treatment of miscellaneous service charges and returned check fees is consistent with treating uncollectible expense as a system cost on the uncollectible expense side rather than as an expense attributable to a single class.

Mutual Aid

273. SPS provides mutual aid to other utilities to help respond to natural disasters.

274. Under mutual aid agreements between SPS and other utilities, SPS receives reimbursement for the assistance it provides.

275. It is reasonable to allocate mutual aid reimbursement to classes on a total plant basis.

Electric Vehicle and Fuel Tax Credit

276. SPS's allocation of electric vehicle and fuel tax credits as overhead costs based upon labor is reasonable.

Separating Residential Service and Residential Service with Electric Space Heating for Purposes of Allocating Distribution Costs

277. [DELETED]

277A. It is unreasonable for SPS to allocate distribution costs separately to the customers who take service under the general-residential-service rates and the customers who take service under the rates for residential service with electric space heating because all of these customers compose a single residential class.

277B. SPS's distribution costs should be allocated to the Residential Class as a whole rather than separately to the general-residential-service customers and residential-space-heating customers.

Distribution Substations Allocator

278. SPS properly allocated the costs of distribution substations among customer classes based on a non-coincident peak allocator.

279. Distribution substations are built by SPS to transform transmission voltage and provide distribution voltage to customers taking service at distribution voltage in localized areas.

280. The substations do not serve transmission voltage customers.

281. The substations are not sized to handle the system peak, but instead are sized to handle the customer loads in specific localized areas of the system.

282. A non-coincident peak allocation better reflects the end-use load characteristics of the transformation provided at the substations and is, therefore, reasonably applied.

Account 368 – Distribution Line Transformers

283. It is reasonable to distinguish between capacitors and transformers for purposes of allocating costs within FERC Account 368.

Account 556 – System Control Dispatching-Generation

284. SPS incurs costs recorded in FERC Account 556 for system control and dispatching of the production system.

285. Load dispatching reflects SPS's operation of its production, transmission, and distribution systems.

286. Load dispatching is a daily operation that occurs throughout the year every hour of every day, and must meet reliability requirements during peak and low-demand times.

287. Peak demand usage is included in each class's average demand over the course of a year.

288. A 12CP demand allocator is based on the average coincident peak for each month of the year.

289. The 12CP demand allocator balances the requirement to dispatch load to meet average usage and the requirement to dispatch load to meet maximum annual peak demand.

290. SPS reasonably allocated system control and dispatching costs among customer classes based on 12CP demand in this case and, based on the daily nature of dispatching, average usage throughout the year is an appropriate method for allocation.

Accounts 561.1-.3 – Load Dispatch – Transmission and Account 581 – Load Dispatching-Distribution

291. SPS properly allocated transmission-related load dispatch costs recorded in FERC Account 561 using an average demand allocator.

292. It is reasonable for SPS to allocate distribution-related load dispatch costs recorded in FERC Account 581 using an average demand allocator.

293. SPS dispatches its system every second of every day throughout the year, at peak times and at low-demand times to ensure reliability of the SPS system.

294. Annual line loss-adjusted kWh represents the use of the SPS system throughout the year by a customer class.

295. When the annual kWh of each customer class is compared to other customer classes, the comparison represents each class's relative average use of the SPS system throughout the year, and is the appropriate method of allocating costs for dispatching the SPS system because the activity occurs all day, every day, all year long.

Regional Market Expenses (Accounts 575.1, .2, .5, .6, .7, and .8)

296. Regional market expenses refer to costs charged to SPS by SPP to defray the costs of administering the SPP Open Access Transmission Tariff and of operating SPP's Integrated Marketplace.

297. These expenses are caused by SPS's daily operations undertaken to provide transmission system reliability, which is important throughout the year, both at off-peak and peak demand times.

298. SPS properly allocated the regional market expense included in FERC Account 575 among customer classes based largely on the DTRAN allocator because the majority of these costs represent charges from SPP that are based on transmission peaks.

299. SPS properly allocated smaller amounts of regional market expense according to an energy allocator because such method weights the allocation on the basis of usage throughout the year, including during peak times.

Account 593 – Distribution Maintenance of Overhead Lines

300. Most vegetation management relating to overhead lines in SPS's system occurs on the primary distribution system.

301. In numerous areas of SPS's system, there are secondary lines under the primary lines.

302. SPS's guidelines indicate that the company does not conduct routine pruning on secondary lines.

303. Even if the secondary system occasionally benefits from tree trimming done on SPS's primary system, the secondary system did not cause the expense of such trimming.

304. The costs of vegetation management relating to overhead lines in the SPS system which are caused by the secondary system are very minimal.

305. Allocating vegetation management costs between the primary and secondary distribution systems based on total overhead plant costs does not tend to promote cost of service-based rates.

306. It is more reasonable and consistent with cost causation to classify vegetation management costs as 98% to the primary distribution system and 2% to the secondary distribution system.

Account 902 – Meter Reading Costs

307. [DELETED]

307A. SPS proposed to allocate meter reading costs based on a weighted number of customers. Specifically, SPS counted each primary general, secondary general, or LGS-T customer as

5.97517 customers. In contrast, all customers in the others classes were each counted as a single customer.

308. [DELETED]

308A. SPS failed to prove its proposed weighting of customer counts is reasonable because the proposal was not based on sufficient data nor systematic analysis.

309. [DELETED]

309A. It is reasonable to allocate Account 902 based on the actual customer count, not SPS's proposed weighted customer count.

Account 904 – Uncollectible Accounts

310. SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.

311. Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.

Major Account Representatives (Account 908 – Customer Assistance Expenses and Account 912 – Demonstrating and Selling Expenses)

312. SPS employs major account representatives that serve large customers in the C&I classes (Secondary General Service, Primary General Service, and LGS-T classes), but not customers in the Residential and Small General Service classes or smaller customers in the Secondary General Service class.

313. Assigning a weighting factor of ten to the Primary General Service and LGS-T classes was appropriate to reflect that smaller Secondary General Service customers are not typically served by these representatives.

314. SPS's proposal to allocate costs of major account representatives to the C&I classes (except for smaller Secondary General Service customers) is reasonable and consistent with cost causation principles.

Outside Services-Legal (Account 923)

315. SPS properly allocated the costs incurred in FERC Account 923 for outside legal services on the basis of the SALWAGXAG allocator.

316. It is reasonable to use the SALWAGXAG allocator because SPS engages outside counsel to perform only the work that exceeds the capacity of its in-house legal staff, and the costs of the in-house legal staff are allocated based on SALWAGXAG.

Contributions, Dues, and Donations

317. SPS reasonably allocated the costs of contributions, dues, and donations among customer classes using a labor allocator, SALWAGES, because contributions, dues, and donations are tied to employee activities.

Account 926 – Employee Pensions and Benefits

318. It is reasonable to allocate the employee pension and benefit costs recorded in FERC Account 926 among customer classes using the SALWAGXAG allocator, and the method matches the jurisdictional allocation method.

Historical Energy Efficiency Costs

319. Before 2012, SPS was not subject to the Energy Efficiency Cost Recovery Factor rule, and therefore it recovered energy efficiency costs in base rates.

320. In *Application of Southwestern Public Service Company for Authority to Change Rates, to Reconcile Fuel and Purchased Power Costs for 2006 and 2007, and to Provide A Credit for Fuel Cost Savings,* Docket No. 35763, Order (June 2, 2009), Docket No. 35763, a 2008 SPS base rate case, the parties agreed SPS would be allowed to recover the energy efficiency expenses incurred up to that time over a ten-year period.

321. Customers in the LGS-T classes did not receive services from SPS's historical energy efficiency programs prior to 2008, while the other classes did receive such services.

322. The LGS-T classes did not cause the costs incurred by SPS's historical energy efficiency programs.

323. Industrial customers such as those in the LGS-T classes have economic incentives to fund their own energy efficiency measures, at their own expense and to the benefit of SPS's system and other customers.

324. It is more consistent with cost causation principles to allocate SPS's historical energy efficiency costs to only the classes that received service from the programs, using an energy allocator.

Municipal Franchise Fees

325. SPS imposes two levels of municipal franchise fees: (1) a base level of 2-3% (depending on the franchise agreement) that is embedded in base rates and charged to all customers except for LGS-T customers located outside of municipal boundaries; and (2) an incremental amount that is collected from only the customers in the particular franchise jurisdiction charging the incremental amount.

326. Municipal franchise fees are incurred based solely on in-city electricity usage and the resulting revenues collected from those sales.

327. Based on cost causation principles, it is reasonable to allocate all municipal franchise fees on the basis of in-city revenues.

Determination of Customer Classes for Allocation and Rate Design Purposes

328. It is reasonable to adopt the following classes for purposes of cost allocation and revenue distribution in this case:

- Residential (including both Residential Service and Residential Service with Electric Space Heating, broken out separately);
- Small General Service;
- Secondary General Service (including Service Agreement Summary customers SAS-4 and SAS-8, as well as standby customers);
- Primary General Service (including standby customers);
- Large General Service – Transmission (69 kV);
- Large General Service – Transmission (115+ kV);

- Small Municipal and School;
- Large Municipal;
- Large School;
- Street Lighting; and
- Guard or Area Lighting.

329. The group of 11 classes is large enough to draw meaningful distinctions between customers based on their usage characteristics and the demands they make on the electrical system.

330. The group of 11 classes remains sufficiently general to avoid decomposition of costs and rates into specialized end uses.

331. In prior cases, SPS allocated costs to the customer classes as a whole using the AED-4CP allocation factor, with all costs allocated to the C&I classes considered together. SPS then distributed the revenue requirement to the C&I classes based on billing demand.

332. In this case, SPS reasonably allocated costs separately to the individual C&I classes using the AED-4CP allocation factors, and then it performed the class revenue increase distribution by calculating the class revenue targets based on that same approach.

333. SPS's allocation approach for the C&I classes will reduce the possibility of hidden subsidies between these classes and properly considers the differences between these classes concerning their effects on the SPS system.

334. SPS's allocation approach is reasonable because it allocates costs more consistently with cost-causation principles than the method it used in prior cases.

Revenue Distribution

Gradualism Adjustment

335. [DELETED]

335A. The rates adopted in this proceeding reflect a less than 1% decrease to SPS's Texas retail revenue requirement.

335B. The revenue responsibilities of all classes, except the Street Lighting class, increase or decrease nor more than 14% from their present revenue responsibilities.

335C. The Street Lighting class's revenue responsibility will increase 24.28%. However, the Commission previously determined in Docket No. 40443 that an increase as large as 29% did not warrant rate mitigation.

336. [DELETED]

336A. No party proved that an adjustment for gradualism, which moves away from cost-based rates and requires cross-class subsidization, is appropriate in this proceeding.

337. [DELETED]

337A. SPS's request that the maximum increase in rates for any one class be capped at 200% of the system average increase, and that no class receive a rate decrease, is unreasonable and is not adopted.

337B. All other gradualism-adjustment proposals, including those of TIEC, Occidental, and AXM, are unreasonable and are not adopted.

337C. Each class's rates set in this proceeding should be based on the costs to serve that class.

<u>Proposed Revenue Distribution</u>

338. The Commission-adopted revenue distribution is reasonable and consistent with cost causation principles.

<u>Classes for Revenue Distribution in Future Cases</u>

339. It is inappropriate for the Commission to determine parameters or requirements for rate classes to be approved in future base-rate proceedings.

339A. The Commission approves the following 11 rate classes in this base-rate proceeding: residential service; small general service; secondary general service; primary general service; large general service – transmission, 69-115kV; large general service – transmission, 115kV+; small municipal and school service; large municipal service; large school service; municipal and state street lighting; and guard- and flood-lighting service.

Rate Design

Customer Charge

340. [DELETED]

341. Increasing the service connection charge to the Residential Service class will reduce the amount of capacity costs caused by that class being paid by customers with higher load factors that use capacity more efficiently.

342. The full, component cost of service to a customer in the Residential Service subclass is $10.57 per month and is $10.56 to a customer in the Residential Service with Electric Space Heating subclass.

343. SPS's proposal to increase the monthly customer charge for the Residential Service class from the present charge of $7.60 to a proposed charge of $9.50 is reasonable.

Design and Future of Residential Service with Electric Space Heating Rates

344. SPS's request that the Residential Space Heating tariff be closed to new customers as of January 1, 2016 is reasonable.

345. Higher load factors in the winter months for Residential Service With Electric Space Heating customers would unreasonably result in moving rates for the Residential Service and Residential Service with Electric Space Heating subclasses classes further from cost causation principles if the winter discount for Residential Service with Electric Space Heating customers is not increased.

346. SPS's proposed increase in the winter discount rate for Residential Service with Electric Space Heating customers is reasonable and comports with cost causation principles.

Residential Time of Use Rates

347. SPS's proposal to offer an alternative, experimental Time of Use (TOU) rate rider for residential customers is reasonable.

348. The Residential TOU rate option will provide a reasonable alternative to future residential customers with electric space heating or other, significant non-summer consumption.

349. SPS will immediately begin communicating with its customers through bill inserts, website information, and direct contact from service representatives regarding TOU rates.

Small General Service

350. SPS's proposal to an increase the customer charge from $12.67 per month to $12.70 per month for the Small General Service customers is reasonable and reflects the actual customer-related cost for the Small General Service class.

Secondary General Service

351. SPS's proposed rate design for the Secondary General Service class is reasonable.

Primary General Service

352. Both Staff's and SPS's cost of service studies indicate that rates based on cost are higher for the Secondary General Service class than the Primary General Service class.

353. The rate differentials between the demand rates of the Secondary General Service class and the Primary General Service Class at other vertically integrated utilities in Texas are similar to the differentials between those two classes in SPS's cost of service study.

354. A widespread ratchet on Primary General Service customers may cause unreasonable adverse bill impacts on customers with significant off-peak seasonal loads or smaller customers in that class.

355. A demand ratchet would produce improper pricing signals for seasonal customers that have significantly higher loads during the off-peak non-summer months than during the summer months.

356. A demand ratchet may present difficulties for smaller Primary General Service customers that are similar to the kW demand billing difficulties for some Secondary General Service customers that the Rule of 80 is designed to assist.

357. It is not reasonable to establish a demand ratchet for Primary General Service customers.

358. It is not reasonable for SPS to adjust its revenue distribution by pooling the production, transmission, and primary capacity costs for the Primary General Service and Secondary General Service classes and allocating them according to billing demand.

359. It is reasonable and consistent with cost causation principles to allocate production and transmission capacity costs according to AED-4CP, and allocate primary distribution

capacity costs for the Primary General Service and Secondary General Service classes separately to each class according to non-coincident peak demand.

LGS-T

360. SPS should not be required to present a primary transformation or primary substation service class or rate in its next rate case because such a class or rate is unnecessary.

361. It is inappropriate for the Commission to make decisions in this proceeding regarding rate classes for a future rate case.

362. SPS's current approach of leasing individual substations at replacement cost directly assigns substation costs to the very large customers that use each substation and is reasonable.

363. SPS's approach ensures that all costs from remote substations are recovered from the LGS-T customers that use them, and thus comports with cost causation principles.

Collection of Account 908 – Customer Assistance Expenses and Account 912 – Demonstration and Selling Expenses

364. Major account representatives are a service SPS makes available to its customers and is therefore a customer-related cost.

365. It is reasonable for SPS to recover part of this cost from the Secondary General Service class through a service availability charge and the rest through energy and demand charges.

Rule of 80 vs. Rule of 70

366. It is not appropriate or reasonable to revise Tariff Sheets Nos. IV-18, IV-175, and IV-182 to change the Rule of 80 to a Rule of 70.

367. Neither the Rule of 80 nor the Rule of 70 accounts for the timing of low load customers' maximum demand, so both could allow for billing reductions for usage during system peaks.

368. Moving from the Rule of 80 to the Rule of 70 will have a significant effect on the number of low load factor customers, including municipal customers, that will have to pay full demand charges.

369. The costs incurred by SPS as a result of the spikes of demand from low load factor customers at peak hours are considerably lower than the ordinary demand charge.

370. SPS load research data shows that low load factor customers have a very low coincidence with the system peak.

371. The Rule of 80 and the Rule of 70 are both generally cost of service based rates.

372. SPS did not show that moving from the Rule of 80 to the Rule of 70 will bring rates closer to cost of service.

373. It will take time to orient the low load factor customers to the experimental TOU and Low Load Factor rates, and it is unclear whether these rates will offer the same type of mitigation from overly high demand charges to the majority of these customers as does the Rule of 80.

Amarillo Recycling

374. It is reasonable to delete Electric Tariff Sheet No. IV-199 – the Service Agreement Summary applicable to ARC.

375. SPS is offering a Low Load Factor rate, which will be available to all customers served under the Secondary General Service class and the Primary General Service class that have a 25% or less average monthly load factor.

376. The proposed Low Load Factor rate will help ARC control its electric bill, provided that ARC can provide load control similar to what is currently required.

377. If ARC provides load control similar to its current requirement, its rate will increase by 9.32%.

378. The initially proposed Primary General Service rate increase was 12.75%, so the ARC increase is less than the increase applicable to similar C&I customers at primary voltage.

Substation Leases

379. It is unnecessary to require SPS to modify the way it leases substations to customers who take service at transmission voltage because there has been no showing that there is a problem among SPS customers with the current approach.

380. Staff's recommendation to amend SPS's LGS-T tariff and the Electric Service Agreements between SPS and its LGS-T customers is not reasonable given the significant changes required to implement the recommendation.

381. SPS's substation leasing practices are proper and reasonable.

<u>Miscellaneous Preliminary Order Cost Allocation and Rate Design Issues</u>

382. SPS has no existing rate riders that should be modified or terminated, and SPS has proposed no rate riders in this case.

383. The following tariff revisions proposed by SPS are uncontested, are reasonable, and are approved:

- Establishment of experimental TOU rates for customers in the Residential Service, Small General Service, Secondary General Service, Primary General Service, Small Municipal and School Service, Large Municipal Service, and Large School Service classes;

- Establishment of Tariff Sheet No. IV-206, which is a Low Load Factor tariff, for the Secondary General Service and Primary General Service classes;

- Amendment of Tariff Sheet No. IV-56 to delete Chase Bank as a customer listed under the tariff. The outdoor lighting for Chase Bank has been updated, and it no longer requires a service agreement because the lighting can be billed under other generally applicable lighting rates;

- Elimination of Tariff Sheet No. IV-58 because Cal Farley's Boys Ranch no longer takes service under the tariff;

- Revision of Tariff Sheet No. IV-99 to correct references to the company listed in the tariff from "Degussa" to "Orion Engineered Carbons" to reflect the customer's change in name;

- Revision of the Distributed Generation Interconnection tariff to avoid duplication of information. Presently, both the Distributed Generation Interconnection tariff (IV-159) and the Secondary Standby Service tariff (IV-180) provide rates for Secondary Standby Service. SPS proposes to remove the rate information from the Distributed Generation Interconnection tariff and to refer to the Secondary Standby Service tariff for rate information. SPS is also proposing to delete a reference to a discount for service at primary voltage because SPS also offers Primary Standby Service;

- Revision of the applicability section of Small Municipal and School Service and Large School Service tariffs to add language clarifying that the tariffs apply only to K-12 schools, whether public or private;

- Revision of Tariff Sheet Nos. IV-179, IV-180, IV-181, and IV-183 to clarify that, for customers that have power factor metering, the power factor charge will apply. SPS further proposes the addition of a power factor provision to applicable customers with 200 kW loads or greater;

- Revision of Tariff Sheet Nos. IV-18, IV-108, IV-173, IV-175, IV-179, IV-180, IV-181, IV-182, and IV-183 to change billing for power factors below 90% from kVAR-based to kW-based. The 90% power factor allows a 5% grace level before the revised power factor charges are applied. The revised power factor charges ensure a ratio of 95% power factor to metered power factor multiplied by metered kW and the applicable kW charge;

- Revision of Tariff Sheet No. V-14 to change the minimum power factor from 80% lagging to 95% lagging so that it is consistent with power-factor billing;

- Revision of Tariff Sheet No. V-31 to increase the maximum contribution in aid of construction from customers before connecting a deduct or ancillary meter linked to a customer's existing meter;

- Establishment of Tariff Sheet No. V-32 to govern instances in which persons request a temporary raising or lowering of lines; and

The first sentence of the definition of "Load Factor" of Tariff Sheet No. IV-206 should state: "Determined by dividing Customer's monthly metered kWh in each billing cycle by the product of the Customer's maximum kW demand times 24 hours per day of billing."

<u>Procedures and Model for Number Runs and Compliance Tariff</u>

384. The Management Applications Consultants, Inc. is a reasonable tool to use for allocating costs among classes.

VII. Conclusions of Law

1. SPS is a public utility as that term is defined in PURA § 11.004(1) and an electric utility as that term is defined in PURA § 31.002(6).

2. The Commission has jurisdiction over this matter under PURA §§ 14.001, 36.001-36.111, 36.203-36.205, 36.209, and 36.210, and 16 TAC §§ 25.231, 25.238, 25.239, 25.243, and 25.245.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket pursuant to PURA § 14.053 and Tex. Gov't Code Ann. § 2003.049 (West 2008 & Supp. 2014) (APA).

4. This docket was processed in accordance with the requirements of applicable law, including PURA and the Texas Administrative Procedure Act, TEX. GOV'T CODE ANN. Chapter 2001, and the Commission's procedural rules.

5. SPS provided notice of its application in accordance with PURA § 36.103 and 16 TAC §§ 22.51(a) and 25.235(b).

6. Pursuant to PURA § 33.001, each municipality in SPS's service area that has not ceded jurisdiction to the Commission has jurisdiction over SPS's application.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. SPS has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, SPS's overall revenues approved in this proceeding permit SPS a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to SPS in providing service.

11. SPS's proposed post-test year adjustments to rate base violate 16 TAC § 25.231(c)(2)(F)(i)(II) and (ii)(I), and SPS did not show good cause to make an exception to those rule requirements.

12. The ADIT adjustments approved in this proceeding are consistent with PURA § 36.059 and 16 TAC § 25.231(c)(2)(C)(i).

13. Including the cash working capital approved in this proceedings in SPS's rate base is consistent with 16 TAC § 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

14. The return on equity and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

15. 16 TAC § 25.231(b) provides that in computing a utility's reasonable and necessary operating expenses, the Commission should consider historical test year expenses as adjusted for known and measurable changes.

16. PURA § 36.065(b) allows a utility to establish a reserve account to record the difference between the amount of pension and OPEB expense approved in the utility's last general rate case and the annual amount of pension and OPEB expense that the utility actually bears.

17. 16 TAC § 25.231(b)(1)(b) provides that depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission shall be used, but other methods may be used when the Commission determines that such depreciation methodology is a more reasonable means of recovering the costs of plant.

18. The reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

19. The affiliate expenses approved in this proceeding and included in SPS's rates meet the affiliate payment standards articulated in PURA §§ 36.051 and 36.058 and in *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W. 2d 783 (Tex. App.—Austin 1984, no writ).

20. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not demonstrate good cause to make an exception to that rule.

VIII. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following Order:

1. The proposal for decision is adopted to the extent consistent with this Order.

2. SPS's application is granted to the extent consistent with this Order.

3. The findings of fact and conclusions of law in this order are binding, irrespective of whether an ordering paragraph explicitly addresses the same subject.

4. SPS is authorized to file an application to implement a net refund, which reflects that some customer classes will receive a refund and some customer classes will pay a surcharge, to reflect the revenue it would have received for service rendered on and after June 11, 2015, through the date the rates set in this case take effect based upon the tariffs approved in this proceeding.

5. SPS shall file in Tariff Control No. 45442, *Compliance Tariff for Final Order in Docket No. 43695 (Application of Southwestern Public Service Company for Authority to Change Rates*) tariffs consistent with this Order within 20 days of the date of this Order. No later than 10 days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

6. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, SPS shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

7. Copies of all tariff-related filings shall be served on all parties of record.

8. SPS shall investigate (including work with affiliates regarding their charges) and detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M expenses, steps being taken to reduce them, and the timing and cost impact of those steps.

9. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.