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State Corporation Commission
of Kansas

BEFORE THE STATE CORPORATION
COMMISSION OF THE STATE OF KANSAS

In the Matter of a General Investigation Regarding the Rate Study and Assessment Expenses Resulting from Substitute for Senate Bill No. 69.	))))	Docket No. 20-GIME-068-GIE

NOTICE OF FILING OF RATE STUDY

COMES NOW, the Staff of the State Corporation Commission of the State of Kansas ("Staff" and "Commission," respectively) and respectfully files the study of electric rates ordered in Substitute for Senate Bill No. 69. 2019 Kan. Laws Ch. 31 § 1. Among other things, Substitute for Senate Bill No. 69 directed the Kansas Legislative Coordinating Council to authorize a study of retail rates of Kansas electric public utilities, and directed the Commission to make the study available on the Commission's website by January 8, 2020. *See* 2019 Kan. Laws Ch. 31 § 1(a), (b)(4). Staff recommends the Commission accept this filing into Docket No. 20-GIME-068-GIE, and make the study available on the Commission's website as required by Substitute for Senate Bill No. 69.

WHEREFORE, Staff respectively submits the rate study directed by Substitute for Senate Bill No. 69, recommends the Commission accept this filing, and recommends the Commission make the study available on the Commission's website as required by Substitute for Senate Bill No. 69.

Respectfully submitted,

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Study of Retail Rates of Kansas Electric Public Utilities

prepared for Kansas Legislative Coordinating Council ("LCC") by London Economics International LLC

January 8, 2020

London Economics International LLC ("LEI") was retained by the Kansas Legislative Coordinating Council ("LCC") to perform a study of retail rates of Kansas electric public utilities as mandated by Substitute for Senate Bill 69 ("Sub. for SB 69"). This Study is divided into two parts:

1) *the effectiveness of current Kansas ratemaking practices in terms of attracting adequate capital investments, balancing between utility profit and public interest objectives, recovering full or partial costs of any investment no longer fully used or required, contribution of surcharges and riders to rising electricity rates for consumers, and comparison of oversight requirements with surrounding states; and*
2) *options available to the state corporation commission and the Kansas legislature to affect retail electricity prices to become regionally competitive while providing the best practicable combination of price, quality, and service.*

The options, as noted in Sub. for SB 69, including better management of the investor-owned utilities ("IOUs") capital and operation expenditures, establish performance-based regulation ("PBR"), implement retail competition, review tax rates imposed on utilities, an increase in energy efficiency and renewables, and a more active participation in the Southwest Power Pool.

LEI's analysis demonstrates that Kansas needs to adopt a portfolio approach targeted at achieving regionally competitive electricity rates over time. LEI recommends the following near-term steps in order to help achieve that objective:

- *establishing a State energy plan;*
- *mandating integrated resource plans from utilities with a competitive procurement framework;*
- *allowing the KCC to explore the development of initial PBR mechanisms which, over time, could evolve into a more comprehensive PBR framework;*
- *and establish a framework allowing for the securitization of uneconomic assets, given that the cost/benefit analysis of asset retirement demonstrates clear benefits to consumers.*

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Table of contents

1 EXECUTIVE SUMMARY 10

1.1 ABOUT THE PROJECT 10
1.2 EFFECTIVENESS OF RATEMAKING PRACTICES IN KANSAS 11
1.3 OVERVIEW OF THE KANSAS ELECTRICITY INDUSTRY 12
1.4 COMPARATIVE ANALYSIS OF LAWS, REGULATIONS, AND OVERSIGHT IN SURROUNDING STATES 13
1.5 OPTIONS AVAILABLE TO KCC AND THE KANSAS LEGISLATURE 14
1.5.1 Management of capital and operating expenditures 15
1.5.2 Performance-based regulation 15
1.5.3 Economic development rates 16
1.5.4 Retail competition 17
1.5.5 Investments in energy efficiency and renewables 18
1.5.6 Securitized ratepayer-backed bonds 19
1.5.7 Participation in SPP 20
1.5.8 Review of tax rates 20
1.6 KEY TAKEAWAYS 21

2 ABOUT THE STUDY 24

2.1 STUDY SCOPE 24
2.2 DATA SOURCES 26
2.3 STAKEHOLDER INPUT 27
2.4 CAVEAT 28

3 OVERVIEW OF THE KANSAS ELECTRICITY INDUSTRY 29

3.1 INDUSTRY STRUCTURE 30
3.1.1 Generation 30
3.1.2 Transmission 32
3.1.3 Distribution 34
3.1.4 Market participants 34
3.2 INSTITUTIONAL ARRANGEMENTS 41
3.2.1 Kansas Corporation Commission 42
3.2.2 Kansas Energy Office 44
3.2.3 Legislative Coordinating Council 44
3.2.4 Citizens Utility Ratepayer Board 45
3.3 ELECTRICITY RATES IN KANSAS 45
3.3.1 Flattening demand 47
3.3.2 Environmental retrofits 48
3.3.3 Transmission costs 48

4 RATEMAKING PRACTICES OF ELECTRIC UTILITIES IN KANSAS 50

4.1 GUIDING PRINCIPLES IN THE RATEMAKING PROCESS 51
4.2 INVESTOR-OWNED UTILITIES 52
4.2.1 Ratemaking process 52
4.2.2 Revenue requirements for generation and distribution 56
4.2.3 Revenue requirements for transmission 63
4.2.4 Rate design 65
4.2.5 Cost recovery mechanisms 67
4.2.6 Contribution of investments made in renewable generation resources and electric transmission resources to the obsolescence of other generation facilities 76
4.2.7 IOU electricity rates 83
4.2.8 Evaluation of the effectiveness of the ratemaking practices 84
4.3 ELECTRIC COOPERATIVES 97
4.3.1 Ratemaking process 98

4.3.2 How revenue requirements are determined ... 99
4.3.3 Cost recovery mechanisms ... 100
4.3.4 Co-op electricity prices ... 101
4.3.5 Evaluation of the effectiveness of the ratemaking practices ... 103
4.4 MUNICIPAL UTILITIES ... 105
4.4.1 Ratemaking process ... 107
4.4.2 Cost recovery mechanisms ... 108
4.4.3 Munis electricity prices ... 110
4.4.4 Evaluation of the effectiveness of the ratemaking practices ... 112
4.5 KEY OBSERVATIONS ... 115
4.5.1 Strengths ... 115
4.5.2 Areas of improvement ... 116

5 COMPARATIVE ANALYSIS OF LAWS, REGULATIONS, AND OVERSIGHT IN SURROUNDING STATES ... 118

5.1 OVERVIEW OF THE SELECTED JURISDICTIONS ... 119
5.2 SUMMARY OF THE SELECTED JURISDICTIONS ... 120
5.3 KEY TAKEAWAYS FROM THE COMPARABLE ANALYSIS ... 122
5.3.1 Key takeaways regarding institutional framework ... 122
5.3.2 Key takeaways regarding policy framework ... 123
5.3.3 Key takeaways regarding the legal framework ... 125

6 OPTIONS AVAILABLE TO KCC AND THE KANSAS LEGISLATURE ... 127

6.1 MANAGEMENT OF CAPITAL AND OPERATING EXPENDITURES ... 128
6.1.1 State energy plan ... 129
6.1.2 Integrated Resource Plan ... 132
6.1.3 Methodical approach in rate case review and analysis ... 136
6.1.4 Competitive procurement framework ... 137
6.1.5 Using a totex framework in PBR ... 139
6.1.6 Incentivize utilities to deploy asset management strategies ... 143
6.1.7 Deregulation of power generation ... 145
6.2 PERFORMANCE-BASED REGULATION ... 147
6.2.1 Performance Incentive Mechanisms ... 149
6.2.2 Earnings sharing mechanisms ... 151
6.2.3 Rate caps ... 152
6.2.4 Outcomes-based PBR ... 153
6.2.5 Other potential PBR parameters ... 154
6.2.6 Jurisdictions under PBR ... 155
6.2.7 Approach to designing rate cap ... 156
6.2.8 Implementation process for a PBR regime ... 158
6.2.9 Impact of PBR regime implementation in other jurisdictions ... 159
6.2.10 Vertically integrated utilities under PBR ... 162
6.2.11 Key considerations for Kansas in implementing PBR ... 164
6.3 ECONOMIC DEVELOPMENT INITIATIVES ... 167
6.3.1 EDRs in neighboring states ... 168
6.3.2 Impacts of EDRs ... 170
6.3.3 Key considerations for Kansas in designing successful EDRs ... 172
6.4 RETAIL COMPETITION ... 174
6.4.1 Different "flavors" of retail competition ... 176
6.4.2 Benefits and challenges of retail competition ... 184
6.4.3 Process to achieve retail competition ... 193
6.4.4 Key considerations for Kansas in designing a successful retail market ... 194
6.5 INVESTMENTS IN ENERGY EFFICIENCY AND RENEWABLE ENERGY ... 196
6.5.1 Renewables ... 196
6.5.2 Energy efficiency ... 198

6.5.3 Would additional renewables or energy efficiency help bring rates down in Kansas? 202
6.5.4 Potential avenues for Kansas to explore 208
6.6 SECURITIZED RATEPAYER-BACKED BONDS 212
6.6.1 Securitization is a risk and time reallocation process 215
6.6.2 Case studies of securitized ratepayer-backed bonds 216
6.6.3 Review of legislative proposal 220
6.6.4 Illustrative impact of securitization in Kansas 222
6.7 PARTICIPATION IN SPP 226
6.7.1 Relevant issues in SPP for Kansas utilities 229
6.7.2 Cost allocation framework 229
6.7.3 Stakeholder participation 230
6.7.4 Kansas participation in SPP committees 230
6.7.5 Involvement of the Kansas Corporation Commission 231
6.7.6 Involvement of Kansas utilities 232
6.7.7 Evaluating the effectiveness of the current approach 233
6.8 REVIEW OF TAX RATES PAID BY UTILITIES IN KANSAS AND NEIGHBORING STATES 236
6.8.1 Overview of the key taxes paid by utilities in Kansas 237
6.8.2 Tax rates in other states 240
6.8.3 Key considerations in changes in the tax rates 248
6.8.4 Concluding remarks 250

7 EVALUATION OF OPTIONS AVAILABLE TO KCC AND THE KANSAS LEGISLATURE 252

8 LIST OF ACRONYMS 259

9 BIBLIOGRAPHY 263

10 APPENDIX A: LIST OF CO-OPS INCLUDED IN THE CALCULATION OF AVERAGE ELECTRICITY PRICES 277

11 APPENDIX B: LIST OF MUNICIPAL UTILITIES INCLUDED IN THE CALCULATION OF AVERAGE ELECTRICITY PRICES 279

12 APPENDIX C: OVERVIEW OF COMPARABLE STATES 281

12.1 ARKANSAS 281
12.1.1 Overview 281
12.1.2 Institutional and legal framework 282
12.1.3 Policy framework 284
12.2 COLORADO 285
12.2.1 Overview 285
12.2.2 Institutional and legal framework 286
12.2.3 Policy framework 288
12.3 IOWA 290
12.3.1 Overview 290
12.3.2 Institutional and legal framework 291
12.3.3 Policy framework 292
12.4 MISSOURI 294
12.4.1 Overview 294
12.4.2 Institutional and legal framework 295
12.4.3 Policy framework 296
12.5 NORTH DAKOTA 298
12.5.1 Overview 298
12.5.2 Institutional and legal framework 299
12.5.3 Policy framework 301
12.6 OKLAHOMA 303
12.6.1 Overview 303
12.6.2 Institutional and legal framework 304

12.6.3 Policy framework *307*
12.7 SOUTH DAKOTA 308
12.7.1 Overview *308*
12.7.2 Institutional and legal framework *309*
12.7.3 Policy framework *310*
12.8 TEXAS 311
12.8.1 Overview *311*
12.8.2 Institutional and legal framework *312*
12.8.3 Policy framework *314*
13 APPENDIX D: SPP MODELING ASSUMPTIONS 316
13.1 FUEL PRICE PROJECTIONS 317
13.1.1 Natural gas *317*
13.1.2 Generic new entry *318*
14 APPENDIX E: OVERVIEW OF FORECASTING METHODOLOGY 320
15 APPENDIX F: ABOUT LONDON ECONOMICS INTERNATIONAL LLC 321

Table of figures

FIGURE 1. SNAPSHOT OF THE KANSAS ELECTRICITY INDUSTRY 12
FIGURE 2. KEY STATISTICS ACROSS SELECTED STATES 14
FIGURE 3. HIGH-LEVEL EVALUATION OF OPTIONS 22
FIGURE 4. ISSUES EXAMINED UNDER PHASE 1 25
FIGURE 5. OPTIONS AVAILABLE TO THE KCC AND KANSAS LEGISLATURE TO AFFECT RETAIL ELECTRICITY RATES 25
FIGURE 6. MAP OF THE STATES INCLUDED IN THIS STUDY 26
FIGURE 7. LIST OF STAKEHOLDERS 27
FIGURE 8. SNAPSHOT OF THE KANSAS ELECTRICITY INDUSTRY 29
FIGURE 9. ELECTRICITY INDUSTRY STRUCTURE IN KANSAS 30
FIGURE 10. ELECTRIC GENERATION IN KANSAS (2013-2017) 31
FIGURE 11. AVERAGE AGE OF GENERATION ASSETS IN KANSAS 32
FIGURE 12. ADVANCED METER PENETRATION AMONG KANSAS CUSTOMERS 34
FIGURE 13. NUMBER AND RETAIL SALES BY OWNERSHIP (2017) 35
FIGURE 14. MAP OF KANSAS IOU SERVICE TERRITORIES 36
FIGURE 15. NUMBER OF CUSTOMERS SERVED BY INDIVIDUAL CO-OPS IN KANSAS (2018) 38
FIGURE 16. LARGEST MUNIS IN KANSAS BY NUMBER OF CUSTOMERS SERVED (2018) 39
FIGURE 17. OVERVIEW OF KANSAS POWER POOL 41
FIGURE 18. AVERAGE ELECTRICITY RATES IN KANSAS AND REGIONAL STATES (2009 AND 2018) 46
FIGURE 19. AVERAGE ELECTRICITY RATES IN KANSAS BY CUSTOMER TYPE (2009-2018) 46
FIGURE 20. RETAIL SALES IN KANSAS BY CUSTOMER CLASS (2009-2018) 47
FIGURE 21. SUMMARY OF ELECTRIC UTILITY TYPES 50
FIGURE 22. RATEMAKING PROCESS IN KANSAS 53
FIGURE 23. SETTLED VS. FULLY LITIGATED RATE CASES IN KANSAS AND SURROUNDING STATES FOR THE PAST TEN YEARS 55
FIGURE 24. AVERAGE DURATION (IN MONTHS) OF RATE CASES FOR THE PAST TEN YEARS 55
FIGURE 25. REVENUE REQUIREMENTS FORMULA FOR AN IOU 56
FIGURE 26. RATE BASE FORMULA 57
FIGURE 27. WESTAR ENERGY RATE BASE PER CUSTOMER (2009-PRESENT) 58
FIGURE 28. KCP&L RATE BASE PER CUSTOMER (2009-PRESENT) 58
FIGURE 29. RATE BASE PER CUSTOMER FOR WESTAR, KCP&L, AND SURROUNDING REGIONS (2017/2018) 59
FIGURE 30. RETAIL SALES (LOAD GROWTH) VS. RATE BASE FOR KANSAS IOUS 60
FIGURE 31. KANSAS IOUS' REQUESTED VS. AUTHORIZED ROES 62
FIGURE 32. ROES IN KANSAS AND SURROUNDING STATES (AVERAGE OF ROES FROM 2010 – 2019) 62
FIGURE 33. COMPONENTS OF OPERATING COSTS 63
FIGURE 34. STEPS IN DETERMINING THE TRANSMISSION REVENUE REQUIREMENT 64
FIGURE 35. KEY STEPS IN THE COS STUDY METHODOLOGY 66
FIGURE 36. TYPES OF CHARGES ON TYPICAL CUSTOMER INVOICES 66
FIGURE 37. COST RECOVERY MECHANISMS 67
FIGURE 38. KEY AREAS CONSIDERED IN THE EVALUATION OF ECA APPLICATIONS 68
FIGURE 39. APPROVED ECA TO DATE 69
FIGURE 40. WESTAR ENERGY APPROVED ECRR (2009-2015) 70
FIGURE 41. KCC-APPROVED TDC (DERIVED BY SPP USING FERC FORMULA) (2009-2015) 71
FIGURE 42. APPROVED AD VALOREM TAX RIDERS (2009-PRESENT) 72
FIGURE 43. APPROVED EERS (2009-PRESENT) 73
FIGURE 44. WESTAR ENERGY COST RECOVERY RIDERS & ADJUSTMENTS VS. RATES (2009-PRESENT) 74
FIGURE 45. KCP&L TRENDS ON COST RECOVERY MECHANISMS AND OVERALL RATES (2009-PRESENT) 75
FIGURE 46. EMPIRE DISTRICT TRENDS ON COST RECOVERY MECHANISMS AND OVERALL RATES (2009-PRESENT) ..75
FIGURE 47. CUMULATIVE RETIREMENTS IN KANSAS (2009 – 2018) 76
FIGURE 48. CUMULATIVE RETIREMENTS IN SPP (2009 – 2018) 77

FIGURE 49. ANNUAL AVERAGE DAY-AHEAD ENERGY PRICE FOR WESTAR PRICE ZONE (2014 – 2018) 77
FIGURE 50. ANNUAL AVERAGE DAY-AHEAD ENERGY PRICE FOR MAJOR PRICE ZONES IN SPP (2014 – 2018).....78
FIGURE 51. MW-WEIGHTED AVERAGE AGE OF PLANT RETIREMENTS IN KANSAS AND SPP 79
FIGURE 52. PANHANDLE GAS PRICES (2014-2018).....80
FIGURE 53. CUMULATIVE NEW ENTRY OF RENEWABLES IN KANSAS (2009 – 2018) 81
FIGURE 54. CUMULATIVE NEW ENTRY OF RENEWABLES IN SPP (2009 – 2018) 81
FIGURE 55. INCREMENTAL NEW ENTRY OF RENEWABLES VERSUS RETIREMENTS IN KANSAS (2000 – 2018) 82
FIGURE 56. CUMULATIVE TRANSMISSION LINES IN MILES (2009-2018) 82
FIGURE 57. TRANSMISSION INVESTMENTS VERSUS RETIREMENTS IN KANSAS.....83
FIGURE 58. RETAIL RATES FOR IOUS BY CUSTOMER CLASS (2009-2018) 83
FIGURE 59. GUIDING PRINCIPLES IN THE RATEMAKING PROCESS.....84
FIGURE 60. EVERGY, INC. STOCK PRICES (2014-2019) 86
FIGURE 61. DOW JONES UTILITIES INDEX, GREAT PLAINS ENERGY, AND WESTAR ENERGY (2014-PRE-MERGER 2018) 86
FIGURE 62. DOW JONES UTILITIES INDEX AND EVERGY INC. (POST-MERGER 2018-2019).....87
FIGURE 63. AVERAGE P/E RATIO OF SELECTED PARENT COMPANIES OPERATING IN THE REGION (JUNE 5, 2018 – DECEMBER 23, 2019.....87
FIGURE 64. EVERGY, INC. DEBT AND EQUITY TRANSACTIONS 88
FIGURE 65. RESIDENTIAL ELECTRIC RATES (CENTS/KWH) FOR THE THREE IOUS IN KANSAS (2009 – 2018) 89
FIGURE 66. RESIDENTIAL ELECTRIC RATES (CENTS/KWH) IN KANSAS AND SURROUNDING STATES.....89
FIGURE 67. KCP&L AND WESTAR ENERGY INC.'S SAIDI AND SAIFI (2014-2018).....90
FIGURE 68. KCP&L AND WESTAR ENERGY INC.'S CAIFI (2014-2018).....91
FIGURE 69. COMPARISON OF THREE-YEAR AVERAGE SAIDI AMONG SELECTED IOUS IN THE REGION (2016-2018) 91
FIGURE 70. COMPARISON OF THREE-YEAR AVERAGE SAIFI AMONG SELECTED IOUS IN THE REGION (2016-2018) 92
FIGURE 71. COMPARISON OF CAIDI AMONG SELECTED IOUS IN THE REGION (2018).....92
FIGURE 72. HISTORICAL CAPACITY FACTORS FOR COAL PLANTS IN KANSAS (2007 – 2018).....94
FIGURE 73. AVERAGE CAPACITY FACTORS FOR COAL PLANTS IN KANSAS AND SURROUNDING STATES (2018) 94
FIGURE 74. CAPACITY FACTOR OF COAL PLANTS IN KANSAS AND SURROUNDING STATES BY ONLINE YEAR.....95
FIGURE 75. AVERAGE CAPACITY FACTORS FOR NATURAL GAS (GT) PLANTS IN KANSAS AND SURROUNDING STATES (2018) 96
FIGURE 76. CAPACITY FACTOR OF NATURAL GAS (GT) PLANTS IN KANSAS AND SURROUNDING STATES BY YEAR OF CONSTRUCTION 96
FIGURE 77. CO-OP PRINCIPLES.....97
FIGURE 78. RATE-SETTING PROCESS FOR ELECTRIC CO-OPS 99
FIGURE 79. AVERAGE ELECTRICITY PRICES OF CO-OPS IN KANSAS (CENTS/KWH) 101
FIGURE 80. 2018 AVERAGE RESIDENTIAL ELECTRICITY PRICES OF CO-OPS IN THE REGION (CENTS/KWH) 102
FIGURE 81. 2018 AVERAGE COMMERCIAL ELECTRICITY PRICES OF CO-OPS IN THE REGION (CENTS/KWH) 102
FIGURE 82. 2018 AVERAGE INDUSTRIAL ELECTRICITY RATES OF CO-OPS IN THE REGION (CENTS/KWH).....103
FIGURE 83. AVERAGE RESIDENTIAL RETAIL ELECTRIC RATES FOR CO-OPS OPERATING ONLY IN KANSAS 104
FIGURE 84. 2018 AVERAGE RESIDENTIAL RETAIL ELECTRIC PRICE FOR CO-OPS OPERATING ONLY IN KANSAS 104
FIGURE 85. KEY ATTRIBUTES OF MUNICIPAL UTILITIES 106
FIGURE 86. RATE SETTING PROCESS FOR MUNICIPAL UTILITIES 108
FIGURE 87. OTHER RIDERS CHARGED BY MUNIS IN KANSAS.....109
FIGURE 88. GARDEN CITY'S CUSTOMER CHARGE BY CUSTOMER CLASS 110
FIGURE 89. HISTORICAL AVERAGE RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL ELECTRICITY PRICES FOR KANSAS MUNIS, 2009-2018.....111
FIGURE 90. 2018 AVERAGE RESIDENTIAL ELECTRICITY PRICES FOR MUNIS IN THE REGION 111
FIGURE 91. 2018 AVERAGE COMMERCIAL ELECTRIC PRICES FOR MUNIS IN THE REGION 112
FIGURE 92. 2018 AVERAGE INDUSTRIAL ELECTRIC PRICES FOR MUNIS IN THE REGION 112

FIGURE 93. HISTORICAL RETAIL RATES FOR MUNIS, 2009-2018 113
FIGURE 94. RETAIL RATES FOR MUNIS BY CUSTOMER CLASS IN KANSAS, 2009-2018 114
FIGURE 95. SELECTION PROCESS TO IDENTIFY JURISDICTIONS TO STUDY 119
FIGURE 96. KEY STATISTICS ACROSS SELECTED STATES 120
FIGURE 97. MAP OF SELECTED STATES 120
FIGURE 98. BRIEFING SUMMARY ON SELECTED STATES 121
FIGURE 99. REGULATOR MANDATES ACROSS ALL STATES 122
FIGURE 100. SUMMARY OF ENERGY PLANS IN EACH STATE 124
FIGURE 101. RENEWABLE AND CLEAN ENERGY STANDARDS IN EACH STATE 126
FIGURE 102. OPTIONS AVAILABLE TO THE KCC AND KANSAS LEGISLATURE TO AFFECT RETAIL ELECTRICITY RATES 127
FIGURE 103. SUMMARY OF REGIONAL STATES' ENERGY PLANS 131
FIGURE 104. STATES REQUIRING UTILITIES TO FILE AN IRP WITH THEIR REGULATOR 133
FIGURE 105. HIGH-LEVEL ILLUSTRATION OF BUILDING BLOCK VS. TOTEX APPROACH 141
FIGURE 106. CHANGE IN RELATIVE AVERAGE ELECTRICITY RATES AMONG REGIONAL STATES FROM 2000 TO 2018 146
FIGURE 107. CONTINUUM OF PBR REGULATION FROM "LIGHT" TO "COMPREHENSIVE" KEY MECHANISMS 149
FIGURE 108. SAMPLE JURISDICTIONS THAT HAVE IMPLEMENTED PIMS 150
FIGURE 109. EXAMPLE OF A SYMMETRICAL SHARING 152
FIGURE 110. SELECTED JURISDICTIONS AND THEIR ESM PROVISIONS 152
FIGURE 111. KEY COMPONENTS TO CONSIDER FOR A PBR FORMULA 155
FIGURE 112. EXAMPLES OF JURISDICTIONS THAT HAVE USED, ARE CURRENTLY USING, OR PLAN TO MOVE TO PBR 156
FIGURE 113. FORMS OF PBR AND APPROACHES OF SETTING RATES IN SELECTED JURISDICTIONS 158
FIGURE 114. HYDRO ONE'S SELECTED PERFORMANCE METRICS (2013-2018) 161
FIGURE 115. CAPITAL ADDITIONS OF TRANSMISSION AND DISTRIBUTION UTILITIES IN ONTARIO 162
FIGURE 116. OMPA'S EDR DISCOUNT SCHEDULE 169
FIGURE 117. ENTERGY ARKANSAS' EDR OPTIONS 170
FIGURE 118. BENEFITS AND DRAWBACKS OF EDRS 171
FIGURE 119. DESIGN CONSIDERATIONS FOR EDRS 173
FIGURE 120. MARKET DESIGN WITH AND WITHOUT RETAIL COMPETITION 175
FIGURE 121. PRESENCE OF RETAIL COMPETITION ACROSS THE US, AS OF 2018 176
FIGURE 122. CONTINUUM OF UTILITY ENGAGEMENT UNDER RETAIL COMPETITION 177
FIGURE 123. CUSTOMERS SERVED BY EGSS, 2010-2018 182
FIGURE 124. RESIDENTIAL CUSTOMERS SERVED BY A RES, 2011-2018 183
FIGURE 125. PERCENTAGE CHANGE IN RETAIL PRICE FROM THE PREVIOUS YEAR, RETAIL VS. NON-RETAIL STATES 185
FIGURE 126. TRENDS IN GREEN PROCUREMENT, 1998-2018 187
FIGURE 127. SAMPLE OF CUSTOMER SERVICE OFFERINGS 187
FIGURE 128. BASIC COMMUNITY SOLAR PROGRAM STRUCTURE 189
FIGURE 129. TIMELINE OF TRANSITIONING TO RETAIL COMPETITION FOR SELECT STATES 190
FIGURE 130. CONSUMER PROTECTION RULES IN ILLINOIS 191
FIGURE 131. PROCESS OF IMPLEMENTING RETAIL COMPETITION 193
FIGURE 132. EXAMPLE OF A PRICE TO COMPARE WEBSITE 194
FIGURE 133. AVERAGE WIND SPEEDS IN THE US 197
FIGURE 134. SUMMARY OF ECONOMIC TESTS FOR ECONOMIC EFFICIENCY 200
FIGURE 135. KANSAS RELATIVE RANK IN ENERGY EFFICIENCY MEASURES 202
FIGURE 136. FORECAST ENERGY MARKET PEAK AND ALL-HOUR PRICES IN THE KANSAS ZONE (2020-2029) 204
FIGURE 137. FORECAST ENERGY MARKET BASE CASE AND HIGH RENEWABLES CASE PRICES IN THE KANSAS ZONE (2020-2029) 204
FIGURE 138. ILLUSTRATIVE ENERGY EFFICIENCY EVALUATION FRAMEWORK FOR KANSAS 207

FIGURE 139. ILLUSTRATION OF THE ANNUAL COST BEFORE AND AFTER SECURITIZATION 214
FIGURE 140. EXAMPLE OF ANNUAL RATE IMPACT OF SECURITIZATION (5% INTEREST RATE) 215
FIGURE 141. ASSUMPTIONS RELATED TO EVERGY COAL GENERATION ASSETS SECURITIZATION ANALYSIS 224
FIGURE 142. DIFFERENCE IN RATEPAYER BURDEN OF JEFFREY ENERGY CENTER WITH AND WITHOUT SECURITIZATION (NOMINAL $ MILLION) 225
FIGURE 143. SPP ORGANIZATIONAL CHART 226
FIGURE 144. SPP ENERGY MIX AND HISTORICAL PRICES 228
FIGURE 145. RELATIONSHIP BETWEEN SPP AND KANSAS UTILITIES 228
FIGURE 146. HIGHWAY/BYWAY COST ALLOCATION FRAMEWORK 229
FIGURE 147. SPP COMMITTEES WHERE KANSAS STAKEHOLDERS PARTICIPATE 231
FIGURE 148. OVERVIEW OF SPP STAKEHOLDER PRIORITIZATION PROCESS 233
FIGURE 149. SUMMARY OF EVALUATION OF SPP STAKEHOLDER PROCESS 235
FIGURE 150. SUMMARY OF TAXES PAID BY UTILITIES ONLY IN KANSAS 237
FIGURE 151. SALES AND USE TAX RATES (STATE-LEVEL) 242
FIGURE 152. CORPORATE INCOME TAX RATE (STATE-LEVEL) 243
FIGURE 153. PREVAILING CORPORATE INCOME TAX RATE (STATE-LEVEL) 244
FIGURE 154. ASSESSMENT RATES BY STATES 246
FIGURE 155. SUMMARY TABLE OF KEY TAX RATES IN KANSAS AND NEIGHBORING STATES 250
FIGURE 156. EVALUATION CRITERIA 253
FIGURE 157. HIGH-LEVEL EVALUATION OF OPTIONS 253
FIGURE 158. SNAPSHOT OF ARKANSAS' ELECTRICITY INDUSTRY 281
FIGURE 159. SNAPSHOT OF COLORADO'S ELECTRICITY INDUSTRY 286
FIGURE 160. SNAPSHOT OF IOWA'S ELECTRICITY INDUSTRY 290
FIGURE 161. IOWA ENERGY PLAN'S PILLARS AND OBJECTIVES 293
FIGURE 162. SNAPSHOT OF MISSOURI'S ELECTRICITY INDUSTRY 294
FIGURE 163. SNAPSHOT OF NORTH DAKOTA'S ELECTRICITY INDUSTRY 299
FIGURE 164. SNAPSHOT OF OKLAHOMA'S ELECTRICITY INDUSTRY 304
FIGURE 165. SNAPSHOT OF SOUTH DAKOTA ELECTRICITY INDUSTRY 309
FIGURE 166. SNAPSHOT OF TEXAS ELECTRICITY INDUSTRY 312
FIGURE 167. SPP FOOTPRINT AND REGIONAL TRANSMISSION INTERFACE LIMITS 316
FIGURE 168. HISTORICAL SPP ZONAL PRICES IN KANSAS AND MISSOURI (2015-2019 YTD) 317
FIGURE 169. LEI'S GAS PRICE PROJECTION FOR EL PASO SAN JUAN (2020-2029) 318
FIGURE 170. COST OF GENERIC NEW ENTRY ASSUMPTIONS FOR SPP, 2019 319
FIGURE 171. POOLMOD'S TWO-STAGE PROCESS 320

1 Executive summary

1.1 About the project

Through a competitive sealed proposal procurement led by the Kansas Legislative Coordinating Council ("LCC"), London Economics International LLC ("LEI") was contracted to perform Phase I of a Rate Study ("the Study") which was mandated by the Kansas Legislature in the Substitute for Senate Bill No.69 ("Sub. for SB 69"). The Study aims to "assist future legislative and regulatory efforts in developing an electric policy that includes regionally competitive rates and reliable electric service."[1] The Study focuses on Kansas electric public utilities (as defined in Chapter 66 of the Kansas Statutes Annotated), and includes Kansas Investor Owned Utilities ("IOUs"), electric cooperatives ("co-ops"), and the three largest municipally owned or operated electric utilities ("munis") by customer count.[2]

Phase I of the Study consists of two parts:

- Part 1 involves evaluating the effectiveness of current ratemaking practices for Kansas' IOUs, co-ops, and three largest munis. For IOUs, the evaluation focuses on evaluating the impacts of their ratemaking practices in terms of attracting adequate capital investments, balancing between utility profit and public interest objectives, recovering full or partial costs of any investment no longer fully used or required, the contribution of surcharges and riders to rising electricity rates for consumers, and comparing oversight requirements with surrounding states. For co-ops and munis, the evaluation focuses on the extent to which their ratemaking practices are aligned with the public interest.
- Part 2 focuses on evaluating various options available to make retail electricity rates in the State become regionally competitive. These options, as noted in Sub. for SB 69, include utilities' capital and operation expenditure management, performance-based regulation ("PBR"), retail competition, tax rates imposed on utilities, an increase of energy efficiencies and renewables, and regulatory changes.

LEI conducted this Study through a thorough review of over 250 documents, including relevant statutes, Kansas Corporation Commission ("KCC") Decisions and Orders, as well as other publicly available reports and websites, which are cited in Section 9. LEI also conducted six meetings with stakeholders in Topeka, Kansas, on September 30, 2019, and October 1, 2019. LEI notably met with key representatives from the LCC, KCC, IOUs, co-ops, munis, consumer groups, and environmental groups in Kansas. For stakeholders that were not able to attend the meetings, LEI also conducted separate conference calls. Overall, LEI interacted with 17 stakeholders, which are listed in Section 2.3.

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[1] Kansas Legislature. *Electric Rate Study; Sub. For SB 69.* April 18, 2019.

[2] Ibid.

1.2 Effectiveness of ratemaking practices in Kansas

Under the key areas summarized in Sub. for SB 69, LEI evaluated the effectiveness of ratemaking practices for IOUs across the following key areas:

- attracting adequate capital investments and discouraging unnecessary capital investments;
- balancing utility profits with public interest objectives of achieving regionally competitive rates and reliable service; and
- recovering the partial or full costs of investments no longer used or required to be used from consumers.

Based on a thorough analysis of relevant statutes, prior rate cases and rate studies, data provided directly by the utilities, and input from relevant stakeholders, LEI concluded that current ratemaking practices in Kansas feature strengths as well as areas for improvements.

In terms of strengths, LEI concluded that:

1. the current ratemaking practices for IOUs perform well in terms of attracting adequate capital investments, as evidenced by the liquidity of Evergy's shares and its ability to raise debt and equity;
2. the KCC current primary objective standards (as summarized in K.S.A. 66-128 et sq. and K.S.A 66-1239) and vetting processes ensure that IOU capital investments are indeed required to provide adequate and reliable services to ratepayers; and
3. current ratemaking processes for Kansas electric co-ops and munis are in the public interest. The ratemaking processes for co-ops and munis are similar in terms of ensuring the primacy of consumer interests. The customers own the co-ops that serve them while munis are owned by the cities or towns they serve. Moreover, both co-ops and munis in Kansas encourage the participation of members in their ratemaking process through hearings and stakeholder meetings, thereby ensuring that the views of the customers they serve are appropriately reflected in their rates.

On the other hand, LEI identified three key areas for improvement:

1. the current IOU ratemaking practices reflect some degree of imbalance between utility incentives and public interest objectives (such as achieving regionally competitive rates or other public policy objectives). For instance, retail rates for Kansas consumers have generally increased in the last decade to become higher than the regional average;
2. while the KCC's primary objective standards and vetting process for ensuring the prudence of utility investments are sound, they are limited in terms of protecting ratepayers from paying for investments that are ***underutilized***. For instance, declining capacity factors of currently operating rate-based Kansas coal plants (two of which have capacity factors significantly below the regional average) suggest a need to periodically review their usefulness; and

3. finally, there is potential for improvement in the processes for review of recovery of surcharges and riders. The Environmental Cost Recovery Rider ("ECRR") has contributed, on average, to 35.9% for Westar Energy's total bill from 2009 to 2018. The Energy Cost Adjustment ("ECA") has contributed on average to 15.2% and 33.6% of KCP&L's (2009-2018) and Empire District's (2010-2019) total bills, respectively. In recent years, the Transmission Delivery Charge ("TDC") has also been a key driver of increasing retail electric rates in Kansas, contributing to higher costs to consumers. While the current ratemaking process involves a review of the TDC to ensure consistency with Southwest Power Pool's ("SPP") revenue requirements and rates, this review has a limited impact on the TDC values and authorized returns on the transmission-related revenue requirements for IOUs in Kansas. The base rate still comprises more than 50% of the total bill for all the IOUs.

1.3 Overview of the Kansas electricity industry

Electric generation in the state includes over 15.6 GW of installed capacity as of the end of 2018, with coal, gas, and wind as the dominant generation fuels/technologies. As of 2018, coal-fired generation capacity comprised 30%, gas-fired generation was 24%, and wind made up 34%. A snapshot of Kansas' key electricity statistics is illustrated in Figure 1.

Figure 1. Snapshot of the Kansas electricity industry

Key facts (2018 unless specified)	
Installed capacity	15,631 MW
Demand	42.0 TWh
Load growth (2014-2018)	0.9%
Transmission lines	4,800 miles
Population	2.91 million
GDP growth (nominal, 2014-2018)	3.0%

Installed capacity by fuel type (2018)

Total generation by fuel type (2018)

Installed capacity by ownership (2019)

Sources: EIA data; Commercial third-party database; Bureau of Economic Analysis

The electricity sector includes IOUs, munis, and co-ops. All IOUs are vertically integrated and are regulated by the KCC. Munis and co-ops are not under KCC's jurisdiction and include generation and transmission utilities, transmission and distribution utilities, and distribution-only utilities. There are two traditional IOUs, namely Evergy[3] and Empire District Electric ("EDE" or "Empire"),[4] 32 co-ops, and 118 munis. There is no retail competition in the state, and all utilities have exclusive franchise over the retail customers within their service territory.

1.4 Comparative analysis of laws, regulations, and oversight in surrounding states

While all US states are unique with respect to resource endowment, economic activity, and approach to electric supply, there are lessons to be learned through comparative analysis. LEI selected eight US states as comparators.

In each of the selected states, LEI highlighted the important features of the electricity supply industry, and identify key issues and lessons arising from a detailed review of each state. LEI determined key characteristics to identify eight relevant states, using the following criteria:

- states that have **significant quantities of renewables** in their energy mix;
- states with **multiple utility ownership models** serving their customers;
- states with a **mix of rural and urban** customers;
- states with **sizeable natural resource extraction** industries; and
- geographic **proximity to Kansas**.

Although Kansas is the third largest of the states studied by area, it ranks lower in terms of electric demand and population density and ranks in the middle with respect to installed capacity. Nearly all the selected states participate in an Independent System Operator ("ISO") market, with most states either part of the SPP or Midcontinent ISO ("MISO"). Figure 2 summarizes the key statistics of the states covered in this Study.

In general, Kansas appears to have a similar institutional framework to its comparators with exclusive franchises for electric supply, a single state regulator with a broad rate-setting jurisdiction, and a combination of member-owned, municipal-owned, and investor-owned utilities across the region. Most states also include vertically integrated utilities responsible for generation, transmission, and distribution with an exclusive franchise and regulated by a state commission.

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[3] Westar Energy and Great Plains Energy (parent of Kansas City Power & Light) merged in 2018 to form Evergy Inc.

[4] A third regulated utility, Southern Pioneer Electric Company, is a wholly owned subsidiary of Pioneer Electric Cooperative, Inc.

Figure 2. Key statistics across selected states

Jurisdiction	Installed capacity (MW, 2017)	Demand (TWh, 2017)	Area (sq.km)	Population (2018)	Population density (2018, ppl/sq km)	ISO Participation
Arkansas	14,642	46	137,732	3,013,825	22	Yes (MISO & SPP)
Colorado	16,017	55	269,601	5,695,564	21	No
Iowa	17,671	49	145,746	3,156,145	22	Yes (MISO)
Kansas	16,138	40	213,100	2,911,505	14	Yes (SPP)
Missouri	21,809	76	180,540	6,126,452	34	Yes (MISO & SPP)
North Dakota	8,234	20	183,108	760,077	4	Yes (MISO & SPP)
Oklahoma	26,691	60	181,037	3,943,079	22	Yes (SPP)
South Dakota	4,129	12	199,729	882,235	4	Yes (MISO & SPP)
Texas	123,512	402	695,662	28,701,845	41	Yes (ERCOT)

Source: Energy Information Administration, *State Electricity Profiles*. January 2019; US Census Bureau. *Population Estimate (As of July 1)*. 2018.

Kansas's public electricity policy framework is generally *laissez-faire*,[5] with limited state resources committed to a policymaking role. Small state departments with narrow mandates are common across the region, with the enforcement role mostly attributed to the regulator. Across the comparators, Kansas differs from some states in that it requires neither an Integrated Resource Plan ("IRP") from utilities, nor has a mandatory Renewable Portfolio Standard ("RPS") target.

For decisionmakers in Kansas, the current institutional framework is not unusual compared to regional comparators. Kansas is one of the few states without a mandated IRP process, and a cost-benefit analysis of this process should be considered given the absence of retail competition in the state.

We find that the existing legal framework is adequate to the extent that it meets the existing policy objectives of the state. Kansas does not have more onerous requirements than other states. An RPS mandate for renewables has not been the primary driver for renewable build-out in comparator states, and most will meet their targets due to other factors, such as the availability of federal tax subsidies.

1.5 Options available to KCC and the Kansas Legislature

In Sub. for SB 69, the Kansas Legislature outlined various options to achieve regionally competitive retail electricity rates in the State. These options include utilities' capital and operation expenditure management, performance-based regulation ("PBR"), retail competition, changing tax rates imposed on utilities, an increase in energy efficiency and renewables, and regulatory changes. Accordingly, LEI's evaluation of these options as they relate to achieving regionally competitive rates in Kansas are summarized in the sub-sections below.

[5] In economic theory, *laissez-faire* policy approach refers to the principle of minimal government interference into the economic affairs of individuals and society.

1.5.1 Management of capital and operating expenditures

The current framework for managing capital expenditures ("capex") and operational expenditures ("opex") for Kansas IOUs is a function of Kansas' regulatory environment, where these utilities are vertically integrated and fully regulated for their generation, transmission, and distribution activities. As opposed to liberalized markets, where private investors take on the financial risks associated with building generation assets, Kansas electric consumers assume the risks since, once an investment is approved by the regulator, it is added to the rate base of the regulated utility. The utility generally earns the approved return over the regulated depreciable life of the asset, as long as it remains "used and useful." It is therefore up to the regulator, the KCC in the case of Kansas, to ensure the prudency of capital and operating expenditures.

As such, the KCC staff reviews rate cases based on statutory standards through traditional means. In a regulated environment, several options allow the legislator and regulator to guide utility expenditures and, once guiding principles are established, ensure that the utilities enact state policies in a cost-effective manner.

Notably, a state energy plan would outline state policy priorities and therefore provide high-level guidance for utility investments. With these legislative priorities established, the regulator has several tools to ensure cost-effective investments and operational expenditures. For example, an IRP forces the utilities to forecast their future power needs, study cost-effective solutions to meet future needs[6] and allows the regulator to review and approve the utility's planning based on state policies. Other regulatory mechanisms that would allow for improved capex and opex management include full, non-settled rate cases at least once per decade allowing for a discovery process and the setting of precedent on rate-setting mechanisms; the deployment of a competitive procurement framework to leverage competition for the construction of new assets (as opposed to always relying on the incumbent utility); deploying asset management strategies, which would increase insight into the state of grid systems and help reduce maintenance and capital costs; or adopting a total expenditures ("totex") approach to calculating utilities' revenue requirement as part of a PBR framework.

Another option explored in this Study is the liberalization of the energy industry by deregulating the power generation sector, creating competition for the supply of power, and shifting some of the risks associated with large capital investments to private investors.

1.5.2 Performance-based regulation

PBR is a regulatory approach that aims to provide incentives for regulated utilities to improve their overall efficiency and meet state policy objectives. The PBR approach has several potential advantages over a traditional cost of service ("COS") approach by notably motivating larger efficiency improvements among utilities than traditional COS. It is also expected to create lower rates for customers than a COS regime in the long run and benefit utilities that can exceed industry trends on productivity. Finally, PBR can align utility incentives with state policy

[6] As discussed in subsequent sections, cost-effective solutions can include not only new generation assets but also purchased power, energy efficiency measures, distributed generation resources, or transmission alternatives.

objectives, and reduce the regulatory burden on both utilities and regulators by decreasing the need for frequent regulatory hearings.

Implementation of PBR need not be complex. PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime. A simple set of performance incentive mechanisms with rewards represents a form of PBR and can create incentives for regulated utilities to perform efficiently and meet policy objectives. For Kansas, starting with light PBR mechanisms and gradually moving on to a more comprehensive PBR framework could allow the state to get comfortable with the processes needed to ensure success.

Key success factors in PBR implementation include the PBR design's adaptability to changing environment, the provision of incentives to encourage cost efficiency and quality of service, having a clearly defined and efficient planning process for network investments, and a framework that supports funding of capital expenditure through rates.

Finally, there is no "one size fits all" PBR formula. Stakeholders must work together and recognize their needs and develop their own path to PBR. A regulatory framework from one jurisdiction or utility may not work for another jurisdiction or utility because of numerous factors such as inherent economic and market differences, business practices, policy-driven obligations, and regulatory or institutional requirements. Therefore, a PBR design needs to be customized to the specific environment and circumstances of the regulated utilities. The regulator needs to take each utility's unique characteristics, type of customers served, and underlying economic environment into account, together with state energy policies.

1.5.3 Economic development rates

Economic development initiatives include programs that incent large industrial or commercial customers to locate or expand their businesses within a utility's service territory. Specifically, economic development rates or riders ("EDRs") provide a discount to eligible customers on the utility's standard tariff rates or terms. Currently, some utilities in Kansas provide EDR discounts, but stakeholders in the state believe there is room for expansion. Similarly, economic retention rates could also be considered for existing consumers, if it can be demonstrated that retaining certain current load customers would benefit all customers.

A review of Kansas' neighboring states provides useful examples of the numerous forms in which EDRs are offered. Most of these programs share commonalities, such as requiring customers to add load that exceeds a minimum threshold in order to become eligible for the discount, as well as the duration of the discount agreement (which tends to be a contract of up to 5 years). Based on these jurisdictions, the impacts of EDRs can include both benefits (such as job creation and lower rates for selected customers) as well as potential drawbacks. These potential drawbacks include a narrowed focus on attracting only large, energy-intensive businesses to the local economy, as well as the free-rider problem, which refers to the difficulty regulators and utilities have in surmising whether EDR-eligible customers would have located or expanded their business in the utility's service territory had the incentive not been offered to them. Furthermore, a poorly designed EDR can shift a larger part of the cost burden on other, existing customers.

Before considering EDRs in a jurisdiction, it is important to consider the following questions to ensure their effectiveness and efficiency:

- Are the EDRs necessary to secure the load?
- Are the EDRs appropriately sized?
- Do the EDRs exceed the marginal cost of providing service?
- Do the EDRs put existing load customers at a disadvantage versus new load customers?
- Do the EDRs benefit all ratepayers, or at least do not harm them?

1.5.4 Retail competition

Retail electric choice allows customers to buy electricity from a competitive electricity supplier other than their incumbent utility. Across the country, this choice has taken many forms, which can be categorized into three types:

- ***pure retail competition***, as seen in ERCOT (Texas), where customers across all segments are required to either choose a competitive supplier or have one assigned to them;
- a ***hybrid retail model***, as seen in many of the Northeastern states that have retail competition, where customers are served by default by their incumbent utility but can choose an alternate power supplier; and
- the ***mass aggregation model***, as seen in the Midwest and now California, where municipalities and counties are able to procure electricity from retail electric suppliers on behalf of their residential and small commercial customers.

The perceived benefits and challenges associated with the retail competition are far-ranging. On the one hand, benefits can include reduced electricity prices to end consumers, heightened consumer choice, and innovation in the electricity supply sector (e.g., community solar, renewable gas). On the other hand, key challenges cited are the time and resources required to implement guiding regulatory processes, the need for stringent consumer protection rules, and the additional costs to utilities associated with billing procedures and metering infrastructure, which are needed to align with the product offerings from competitive retailers.

Regardless, the implementation of retail market liberalization tends to follow similar patterns across different jurisdictions, albeit at different paces. The first step is the regulatory process, which sets the framework for the new retail market and is generally preceded by a stakeholder process to obtain input from key stakeholders. Once that framework is established, a working group of regulators, utilities, and retailers needs to work out the mechanics of how the retail market will function on a day to day basis. Finally, there needs to be a strong push for consumer education, leveraging different vehicles to target as wide an audience as possible.

Deciding whether retail competition is right for Kansas requires consideration of numerous factors. First, will retail choice help to decrease costs for consumers? Previous experience from multiple jurisdictions across the country suggests that the answer to this question is yes. Next, how could Kansas explore this transition? This would most likely involve convening a panel of utilities, large customers, as well as representatives of small customers to collect their feedback and ascertain their interest in implementing retail choice in the state. Of course, introducing retail competition is a large regulatory lift, which can span several years. Thus, another consideration would have to be whether the perceived costs outweigh the perceived benefits. An alternative option would be to open retail competition only to commercial and industrial customers, but this again depends on their relative interest and impacts on ineligible customer classes.

1.5.5 Investments in energy efficiency and renewables

Kansas has an abundance of wind and solar resource, with some of the best wind resource in the country. With a large agricultural sector, biomass feedstock is also available for power generation. As of July 2019, Kansas had a total renewable installed capacity of over 6 GW, or 39% of the state's total installed capacity of over 16 GW.[7] This includes over 5.5 GW of installed wind capacity[8] and just under 30 MW of installed solar energy. Kansas currently has a voluntary renewable energy goal which requires utilities to meet 20% of their peak demand using renewable resources by 2020.[9] In addition to the voluntary RPS, Kansas had a property tax exemption in place for renewable resources, limited to ten years for facilities filing an application before December 31, 2016.

With respect to energy efficiency, Kansas does not have an Energy Efficiency Resource Standard ("EERS") and there are currently no requirements set for utilities in the state to offer customer energy efficiency programs. Under the Kansas Energy Efficiency Investment Act ("KEEIA"), the KCC has a mandate to approve proposals by electric and natural gas utilities for efficiency programs and evaluates them on a case-by-case basis. To date, while an energy efficiency rider ("EER") exists, no comprehensive suite of energy efficiency programs has been implemented under the KEEIA framework.[10]

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[7] "US Energy Information Administration - EIA - Independent Statistics and Analysis." *Kansas - State Energy Profile Analysis - (EIA)*, Mar. 2019. Accessed at: <www.eia.gov/state/analysis.php?sid=KS#64.>

[8] AWEA. *Third Quarter 2019 Market Report*. 2019

[9] Kansas Legislature. *House Substitute for Senate Bill No. 91.* Approved by Governor on May 28, 2015.

[10] KCC. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018.

A combination of falling renewables prices and favorable renewables resource suggests that no additional state-mandated incentives are needed to drive increased penetration of renewables. Despite the gradual sunset of federal incentive programs such as the production tax credit ("PTC"),[11] it is expected that the drivers for renewable resources will sustain their continued build-out. To respond to the question of rate impact of additional renewables in Kansas, policymakers should consider whether the goals of the programs would be achieved regardless of policy intervention, i.e., would market drivers lead to similar outcomes of the proposed program.

There may be opportunities with respect to energy efficiency. Currently, the KEEIA has not resulted in any additional energy efficiency programs being implemented. Energy efficiency measures have the potential to reduce costs so that strategic, targeted, and cost-effective energy efficiency programs could help Kansas customers reduce their energy bills; however, not all programs are cost-effective. As such, energy efficiency could be studied as an alternative to new generation resources in utility IRPs.

1.5.6 Securitized ratepayer-backed bonds

Securitized ratepayer-backed bonds are financial assets created for the purpose of lowering current utility rates by using non-bypassable charges to refinance current assets over longer periods. The process for a state to create securitized ratepayer-backed bonds, or securitization is a well-known approach to addressing stranded costs (or other extraordinary costs) in the US. It has been used to recover stranded costs associated with the liberalization of electricity markets, financing environmental control equipment, and more recently, paying for storm recovery costs.

Fundamentally, there is no "magic" in the electric securitization process or ratepayer-backed bonds. The securitization process is, in essence, a risk and time reallocation process, achieved by deliberately carving out a part of the rate base and packaging it with more secure legal arrangements, possibly amortized over a longer period of time.

There are tradeoffs that regulators, electric utilities, and ratepayers should consider before committing to securitization:

- **Amortization period, trading lower rates for higher overall payments over time –** if the interest rate of the ratepayer-backed bond is not low enough, the securitization process would become a tradeoff as a longer repayment term could lower rates in the short term, but ultimately result in higher costs over time. This outcome could create an intergenerational fairness issue as future ratepayers who may have never benefited from the securitized asset would have to bear the cost of financing the asset.
- **Regulators would have less control over a portion of rates once securitization happens –** in order to secure a high credit rating for the ratepayer-backed bonds, regulators would give up control over the non-bypassable charges associated with the

[11] The Renewable Energy Production Tax Credit will be phased down by end of 2019. (Source: Database of State Incentives for Renewables & Efficiency ("DSIRE") website. *Renewable Electricity Production Tax Credit (PTC).* Last Updated February 28, 2018. Accessed on December 16, 2019.

securitization by putting an irrevocable finance order with an automatic adjustment mechanism in force. This means regulators could not influence that portion of the rates.

- **The cost/benefit of retiring the securitized asset must be taken into account** – should the securitized asset be retired, the cost of procuring replacement services (such as energy or capacity provided by a generation asset prior to its retirement) must be taken into account. These costs may, however, be offset by the decrease in operating and maintenance costs of the retired asset. As such, the ultimate cost/benefit analysis of retirement and securitization must be performed holistically, taking into account all cost impacts to ratepayers.

1.5.7 Participation in SPP

While stakeholders have expressed their general satisfaction with participation in SPP, noting greater access to supply and decreasing wholesale prices, there are a number of issues that have been of particular concern to stakeholders in recent years, including transmission cost allocation.[12]

In 2019, SPP commissioned the Holistic Integrated Tariff Team ("HITT") to assess and recommend actions to address concerns with cost allocation, among other issues, across the SPP footprint. The HITT report recommended a revised facility cost allocation review process, whereby specific projects between 100 kV and 300 kV can be allocated on a region-wide basis.[13] With regards to stakeholder participation, there are fewer avenues for non-utility stakeholders to participate, with end-use customers in particular feeling that they either have insufficient resources or are unable to participate meaningfully in the decision-making processes.

Recent trends in SPP, and the implementation of HITT report recommendations, could reduce the burden of future transmission costs for Kansas customers. Kansas stakeholders seeking to advocate certain positions within SPP might also consider a stronger state support framework for more extensive participation in working groups, or in the prioritization process. However, additional support for intervention within SPP or at FERC could increase regulatory uncertainty or delays.

1.5.8 Review of tax rates

The tax rate on electric utilities in Kansas is among the highest relative to neighboring states. Indeed, Kansas tax rates are higher than the regional average across the three tax categories reviewed – sales and use tax, corporate income tax, and property tax assessment rates.[14] As such,

[12] Base on feedback received during meetings with Kansas stakeholders held on October 1, 2019.

[13] SPP Holistic Integrated Tariff Team. *Report: Preparing for a reliable and cost-effective future.* July 23, 2019.

[14] Excluding Texas

some stakeholders have suggested tax reductions as a way to reduce overall electricity costs for ratepayers.

At face value, higher tax rates imposed on Kansas utilities as compared to the regional averages can result in higher consumer electricity rates. However, while reducing the tax rates may help improve the competitiveness of utilities by modestly lowering their costs and providing ratepayers with lower electric rates, this action can also cause socio-economic concerns. For example, state and local governments may suffer from fiscal imbalances, forcing them to increase their revenues from other sources. Furthermore, a cut in corporate income tax may impair the utilities' credit, exposing them to higher borrowing costs and delaying their cashflows associated with deferred tax liabilities.

Therefore, lowering utility borne tax rates alone may not be a solution to address the electricity rates competitiveness issue in Kansas without having unintended side effects.

1.6 Key takeaways

LEI ultimately reviewed the different options available to the KCC and Kansas legislature based on four criteria:

- achieving regionally competitive electricity rates;
- ensuring utility financial health;
- minimizing implementation costs; and
- incentivizing utility efficiency and performance.

The various legislative and regulatory options were evaluated through the scale of "positive, neutral, and poor." Figure 3 provides a graphical summary of this high-level assessment.

There are several options that would help achieve regionally competitive electric rates for Kansas consumers in the long run. However, the impact on rates would vary among the different options since each could target different components of the utilities' revenue requirement (such as generation, transmission, or distribution costs). Additional analysis will be needed to estimate further the costs/benefits of the various options, which are outside the scope of this Study.

Ensuring the financial health of the utility is not only important to ensure the necessary investments in generation, transmission, and distribution to maintain reliable service, but it can also help lower costs for consumers by lowering financing costs for the utilities. Various PBR mechanisms can help in that regard by offering additional returns to the utility when meeting certain objectives set by the regulators based on state policy, or decoupling revenues from sales, thereby reducing variability. EDR mechanisms can also help increase overall load levels, leading to increased revenues for the utility over the long term.

Almost all the options would entail implementation costs to various degrees. These costs could be incurred by the utilities and/or the regulator and may include costs associated with conducting the necessary studies, for stakeholder engagement, for additional personnel, or for new infrastructure.

The utilities' efficiency and performance could be improved through the implementation of various levels of PBR mechanisms, or the introduction of retail competition. This outcome could be achieved under a PBR regime if targets that are set for efficiency and productivity provide balanced rewards for consumers as well as the utilities. Retail competition and deregulation of the generation sector would force utilities to improve their performance to stay competitive.

Figure 3. High-level evaluation of options

	Regionally competitive electricity rates	Ensuring utility financial health	Minimizing implementation costs	Utility efficiency and performance
1) Management of capex and opex	↑		↓	
2) Performance-based regulation	↑	↑	↓	↑
3) Economic development rates	↑	↑	↓	
4) Retail competition	↑	↓	↓	↑
5) Investments in energy efficiency and renewables	↑		↓	
6) Securitized ratepayer-backed bonds	↑		↓	
7) SPP participation	↑		↓	
8) Review of tax rates	↑		↓	

Positive impact ↑

Negative impact ↓

Ultimately, there is no single easy fix that would reduce electricity rates. Kansas needs to adopt a portfolio approach that would gradually achieve regionally competitive electricity rates over time. LEI recommends the following near-term steps in order to help achieve that objective:

- **State energy plan –** The Kansas legislature should create an energy plan for the state. The plan need not be overly long or complicated but can help the State determine what its energy goals are, how to achieve them, and at what cost. The State policy objectives should extend to all entities serving electric customers in the state, including utilities, munis, and co-ops.
- **Integrated Resource Plans –** Regulated utilities should be required to submit IRPs at regular intervals, detailing their plan to meet load requirements over the forecast horizon. All methods of meeting future load requirements (including different technologies, ownership arrangements, or energy efficiency initiatives) should be analyzed to determine the most cost-effective solutions that would also meet the state policy objectives. Competitive procurement for new large generation or transmission assets

should also be considered. Non-regulated utilities should also be required to submit IRPs, or at least demonstrate that their supply portfolio meets the state policy objectives.

- **Performance-Based Regulation –** The Kansas legislature should consider allowing the KCC to explore the development of PBR mechanisms for regulated entities, which over time, could evolve into a more comprehensive PBR framework. The initial implementation, however, needs not be complicated but should, at a minimum, set targets to incentivize utility efficiency, and align utility incentives with customer benefits and state policy objectives.
- **Retirement and securitization of uneconomic assets –** The Kansas legislature should establish a framework allowing for the securitization of uneconomic assets if the cost/benefit analysis of asset retirement demonstrates clear benefits to consumers. However, care should be taken in allowing the utility to grow its rate base following the securitization process, as the utility rate base needs to stay commensurate with the needs of consumers.

Taken together, these near term steps help to address the three key areas for improvement identified in Section 1.2, namely: (1) a degree of imbalance between utility incentives and public interest objectives in the current IOU ratemaking practices; (2) a limitation in the KCC's ability to protect ratepayers from paying for underutilized investments; and (3) the review process for the recovery of surcharges and riders. The first would be addressed through the recommended state energy plan and IRPs. The second would be partially addressed by the retirement and securitization of uneconomic assets, as well as explicitly reviewed through the IRPs. Finally, the third would be addressed through the IRPs, which also have the potential to reduce the need for additional riders in the future.

2 About the study

In April 2019, the Kansas Legislature passed the Substitute for Senate Bill No.69 ("Sub. for SB 69") to conduct a study of the retail rates of Kansas electric public utilities ("Study") that "may assist future legislative and regulatory efforts in developing an electric policy that includes regionally competitive rates and reliable electric service."[15] The Study includes electric public utilities (as defined in Chapter 66 of the Kansas Statutes Annotated), electric cooperatives that are exempt from the jurisdiction of the KCC, and the three largest municipally owned or operated electric utilities by customer count.[16] LEI, through a competitive sealed proposal procurement,[17] was contracted to perform Phase I of the Study.[18] LEI is a US-owned and operated company based in Boston and Chicago. The project kick-off was held on September 30, 2019.

2.1 Study scope

The Study is divided into two phases with Phase 1 focused on examining the effectiveness of current ratemaking practices in Kansas and evaluating options available to the KCC and the Kansas Legislature to affect Kansas retail electricity rates to become regionally competitive and Phase 2 assessing the other consequential energy issues materially affecting Kansas electricity rates. This report focuses only on Phase 1 of the Study, and therefore, any reference to "the Study" in this report refers only to Phase 1.

The first part of Phase 1 involves looking at the current ratemaking process in the State. More specifically, the first part requires LEI to examine the effectiveness of Kansas' ratemaking practices in terms of attracting adequate capital investments, balancing between utility profit and public interest objectives, recovering full or partial costs of any investment no longer fully used or required, the contribution of surcharges and riders to rising electricity rates for consumers, and comparing oversight requirements with surrounding states. It also considers the ratemaking process of the co-ops and munis. Figure 4 lists these items.

LEI is aware of the two prior studies conducted by the KCC and the utilities that looked into the increase in retail electricity rates in the state, and these studies have discussed in detail the primary drivers of these rate increases. The purpose of this Study was not to have LEI repeat the analyses in these rate studies. Instead, where appropriate, LEI built upon some of the prior analyses in this Study. For this Study, LEI focused on evaluating the effectiveness of ratemaking practices in Kansas as they relate to the six key issues summarized in Figure 4.

The second part of Phase 1 requires looking at various options available to make retail electricity rates in the State become regionally competitive. The Legislation listed several options that this

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[15] Kansas Legislature. *Electric Rate Study; Sub. For SB 69.* April 18, 2019.

[16] Ibid.

[17] Request for Proposals for Consulting Services to Perform Study of the Retail Rates of Kansas Electric Public Utilities.

[18] Contract between LCC and LEI signed on August 29, 2019.

Study needs to consider. These include looking into the utilities' capital and operation expenditure management, performance-based regulation ("PBR"), retail competition, tax rates imposed on utilities, an increase of energy efficiencies and renewables, and regulatory changes as shown in Figure 5 below.

Figure 4. Issues examined under Phase 1

Figure 5. Options available to the KCC and Kansas Legislature to affect retail electricity rates

For the purpose of this Study, "region" is defined as the following neighboring states: Arkansas, Colorado, Iowa, Missouri, Oklahoma, North Dakota, South Dakota, and Texas, as illustrated in Figure 6 below.[19] These are the states that will be compared with Kansas in this Study. These states were selected due to their proximity to Kansas, as well as their similarities with the state. Lastly, these are the same states that were studied in KCC's Rate Study.[20]

Figure 6. Map of the states included in this Study

2.2 Data sources

LEI's analytical work used data and information from relevant statutes, PUC Decisions, and Orders, as well as reports from the utilities themselves. LEI also collaborated extensively with the utilities, requesting specific data (if available) to supplement publicly available information. The following key literature was consulted to inform the analyses. Section 9 provides a complete list of documents reviewed in this study.

- Evergy. *Kansas Rate Study. Prepared by Westar Energy & Kansas City Power & Light Company.* January 2019.
- Kansas Corporation Commission. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018.

[19] Nebraska was excluded in the Study because it does not have any vertically integrated IOUs and is served by a public power utility.

[20] Kansas Corporation Commission. "Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2019." December 2018.

- Kansas Corporation Commission. *Electric Supply and Demand Report. Annual Report, 2019.* 2019.
- Southwest Power Pool documents, which include the 2020 Operating Plan, 2018 Annual State of the Market Report. Governing Documents Tariff. Bylaws.
- US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019.

2.3 Stakeholder input

LEI also talked with and gathered the views of stakeholders on the issues relevant to this Study. LEI met with stakeholders in Topeka, Kansas, on September 30, 2019, and October 1, 2019, and conducted calls with other stakeholders who were not able to attend the meetings. Figure 7 shows the list of stakeholders that LEI met or talked with in addition to LCC.

Figure 7. List of stakeholders

Group	Entity
Consumer	Brexco (Oil and Gas Customer)
	Citizens' Utility Ratepayer Board
	Kansas Chamber United for Business
	Kansas Industrial Consumers
Environmental	Climate and Energy Organization
	National Resource Defense Council, Inc.
Regulator	Kansas Corporation Commission
Utility	Evergy
	Kansas City Board of Public Utilities
	Kansas Electric Cooperatives, Inc.
	Kansas Electric Power Coopertive, Inc.
	Kansas Municipal Energy Agency
	Liberty Utilities
	Sunflower Electric Power Corporation
Others	Former PUCT Commissioner
	ITC - A Fortis Company
	SPP

2.4 Caveat

The analyses in this Study were not intended to account for all circumstances in the future. No results provided in the analyses should be taken as a promise or guarantee as to the occurrence of any future events.

Key takeaways

Sub. for SB 69 called for a study of the retail rates of Kansas electric public utilities that "may assist future legislative and regulatory efforts in developing an electric policy that includes regionally competitive rates and reliable electric service." LEI was retained to conduct Phase I of this Study, which is focused on examining the effectiveness of current ratemaking practices in Kansas and evaluating options available to the KCC and the Kansas Legislature to affect Kansas retail electricity rates to become regionally competitive. To do this, LEI conducted a thorough review of over 250 documents, held six stakeholder meetings in Topeka, and conducted separate calls with other interested stakeholders, reaching out to over 17 stakeholder entities to obtain their input and inform the Project Team's analyses.

Source: Kansas Legislature. *Electric Rate Study; Sub. For SB 69.* April 18, 2019.

3 Overview of the Kansas electricity industry

Electric generation in the state includes over 15.6 GW of installed capacity as of the end of 2018, with coal, gas, and wind as the dominant generation fuels/technologies. As of 2018, coal-fired generation capacity comprised 30%, gas-fired generation was 24%, and wind made up 34%. A snapshot of Kansas' key electricity statistics is illustrated in Figure 8.

Figure 8. Snapshot of the Kansas electricity industry

Key facts (2018 unless specified)	
Installed capacity	15,631 MW
Demand	42.0 TWh
Load growth (2014-2018)	0.9%
Transmission lines	4,800 miles
Population	2.91 million
GDP growth (nominal, 2014-2018)	3.0%

Installed capacity by fuel type (2018)

Total generation by fuel type (2018)

Installed capacity by ownership (2019)

Sources: EIA data; Commercial third-party database; Bureau of Economic Analysis

The electricity sector includes IOUs, munis, and co-ops. All IOUs are vertically integrated and are regulated by the KCC. Munis and co-ops are not under KCC's jurisdiction and include generation and transmission utilities, transmission and distribution utilities, and distribution-only utilities. There are two IOUs, namely Evergy Inc.[21] and Empire District Electric ("EDE" or "Empire"), 32 co-ops, and 118 munis. There is no retail competition in the state, and all utilities have exclusive franchise over the retail customers within their service territory.[22]

[21] Westar Energy and Great Plains Energy (parent of Kansas City Power & Light) merged to form Evergy.

[22] This is subject to the Retail Electric Suppliers Act ("RESA") of 1976, which divided the state into service territories and stipulates that "*within each such territory, only one retail electric supplier shall provide retail electric service, and any such territory established for a retail electric supplier pursuant to this section shall be certified to such retail electric*

3.1 Industry structure

As mentioned previously, the Kansas electricity sector is regulated and comprised of vertically integrated utilities and several independent power producers ("IPPs"). Transmission is the responsibility of the SPP, a non-profit membership organization, which as the Regional Transmission Operator ("RTO"), acts as the system operator and market operator for all entities in the state. All Kansas utilities are members of SPP, and the regulator, KCC, maintains a seat on the SPP's Regional State Committee ("RSC").

In these subsections, LEI describes each segment of the electricity supply chain in Kansas, and the institutions responsible for each segment. A summary of the industry structure is illustrated in Figure 9 below.

Figure 9. Electricity industry structure in Kansas

Source: LEI

3.1.1 Generation

The utilities and IPPs own the generation assets, the latter of which are mostly renewable generators. EIA data shows that in 2017, electric utilities (including IOUs, munis, and co-ops) accounted for two-thirds of all generation in the State, while IPPs accounted for 34%.[23] Notably, most municipal generating systems have interconnections with IOU systems, allowing them to purchase power from the IOUs. For example, Evergy has long-term supply contracts to supply Mid-West Energy with 115 MW and 150 MW that run until 2022 and 2025, respectively.[24]

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supplier by the [KCC] and such area shall be provided retail electric service exclusively by such supplier." (Source: Nelson, Natalie. *Kansas Legislator Briefing Book 2019*. 2019)

[23] US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

[24] Westar Energy. *Form 10-K*. December 31, 2016.

While coal-fired generation accounts for most of the generation in Kansas, wind generation has seen an increased share over the past five years. In 2013, coal-fired generation accounted for just over 60% of all generation; by 2017, EIA data shows this has declined to 38%, while wind generation has grown from 19% to 37% over the same period. This is illustrated in Figure 10 below.

Figure 10. Electric generation in Kansas (2013-2017)

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

Kansas generators participate in the SPP Integrated Marketplace ("IM"), which was launched in 2014. The IM is a centralized day-ahead and real-time energy and operating reserve market with locational marginal pricing and market-based congestion management operated by SPP. The IM transitioned utilities from a bilateral real-time market to a day-ahead, co-optimized market.[25] Under this market design, SPP operates a centralized unit commitment process, meaning it determines the generation produced under least-cost dispatch and transmission reliability considerations. A more detailed discussion of SPP is in Section 6.6.4.

For utilities with large coal fleets such as in Kansas, this IM transition has also coincided with a sharp decrease in natural gas prices owing to increased shale production, as well as an increase in wind generation. All these factors have meant a reduction in "off-system" power sales as low marginal cost generation from across the SPP footprint are dispatched ahead of their fleet.[26] In its

[25] Southwest Power Pool website. *Integrated Marketplace.* Accessed at: <https://www.spp.org/markets-operations/integrated-marketplace/>

[26] Evergy. *Kansas Rate Study. Prepared by Westar Energy & Kansas City Power & Light Company.* January 2019. Page 34.

rate study submission, Evergy utilities noted that the result of these factors has seen coal capacity factors decrease from over 70% in 2007 to just over 50% in 2017.[27]

The average age of all plants in Kansas is under 35 years, with coal and hydro plants with average ages of over 40 years, while renewable plants are relatively newer, with an average of six years for wind plants, highlighting the recent build of renewables compared to recent retrofits and refurbishment of the thermal plants, as described in Evergy's Rate Study. This is illustrated in Figure 11 below.

Figure 11. Average age of generation assets in Kansas

Source: Commercial third-party database (Accessed on October 22, 2019)

3.1.2 Transmission

In Kansas, a transmission line is defined as a power line that is at least 5 miles long and used for the transfer of electricity at 230 kV or more.[28] The transmission lines are owned by the IOUs, some co-ops, and munis, while SPP, as the RTO, manages and controls these transmission assets.[29] This also means that SPP administers the billing for transmission services provided by member

[27] Ibid. P.58

[28] Kansas Legislative Research Department. *Electric Transmission in Kansas*. September 2017.

[29] Kansas Corporation Commission. *Transmission & Distribution*. <https://kcc.ks.gov/electric/transmission-distribution>

utilities, including Kansas utilities, and transfers the remits back to the utilities.[30] An overview of the SPP organization is provided in the textbox below.

The Southwest Power Pool

The SPP is a not-for-profit RTO mandated by the Federal Energy Regulatory Commission ("FERC") to manage reliability coordination, wholesale markets, and transmission services using its members' transmission systems. SPP established a real-time energy market in 2007 and moved to an integrated day-ahead and ancillary services energy market in March 2014, referred to as the IM. The IM provides a centralized unit commitment process, and a market co-optimization process to all market participants in the footprint.

SPP is based in Little Rock, Arkansas, and serves 94 members in 14 states of a geographic area of over 575,000 square miles, including all or portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, South Dakota, and Wyoming. This footprint comprises over 800 generating plants and over 60,000 miles of transmission lines.

Source: Southwest Power Pool website. *About us.* <http://www.spp.org/about-us/>

SPP is responsible for cost allocation of transmission lines, and projects approved by SPP are often allocated using the Highway/Byway methodology. A detailed discussion of the cost allocation framework for transmission in Kansas is provided in Section 4.2.3. Other cost allocation methodologies for transmission projects are similar to other regions, i.e., sponsored projects and directly assigned projects whereby the project owner builds and received credit for the use of the transmission lines.[31]

With regards to building transmission, Kansas law states that any utility must obtain siting permits from the KCC before any preparation or work can begin. While SPP addresses and supports the route, it is the responsibility of the state for the actual siting and permitting of the line before any work can begin.[32] KCC must conduct a public hearing on the siting application from a utility within 90 days in one of the counties where the line is proposed to be built and must issue a final order on the application within 120 days after the application was filed. Decisions made by the KCC can be appealed to the Kansas Court of Appeals.[33]

There are several merchant lines at various stages of development, most notably the Grain Belt Express under development by Invenergy (which recently acquired the project from Clean Line Energy Partners). The Grain Belt line is a high-voltage line designed to export wind energy from

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[30] Ibid.

[31] Southwest Power Pool. *SPP 101: An Introduction to Southwest Power Pool.* January 2016.

[32] Kansas Legislative Research Department. *Electric Transmission in Kansas.* September 2017.

[33] Ibid. P.3

Kansas to load centers in Missouri and Illinois. Users would expect to recover their costs from selling electricity to destination loads.[34,35]

3.1.3 Distribution

Distribution to end customers is the responsibility of the public utilities in the State and is performed by IOUs, some co-ops, and munis within their exclusive franchises. Utilities are responsible for the delivery of power to customers within their exclusive service territory, as well as operations and maintenance of their wires infrastructure. Data shows that in 2017, most meters in the State were classified as either advanced meter infrastructure ("AMI") or automatic meter reading ("AMR"), corresponding to 79% and 6% of all meters, respectively. Only 15% of all meters were classified as "standard" meters, of which residential customers accounted for more than three-quarters of this total.[36] Illustrating this data in Figure 12 below, it is evident that while most customers have a form of advanced metering, residential customers form the majority of customers with standard meters.

Figure 12. Advanced meter penetration among Kansas customers

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

3.1.4 Market participants

As mentioned earlier, there are multiple IOUs, co-ops, and munis in the State serving retail customers in their exclusive service territories. In this section, LEI provides an overview of the major market players responsible for serving the majority of Kansas consumers. In 2017, the two IOUs in Kansas comprised over 60% of total retail sales, compared to public and co-op utilities,

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[34] Invenergy website. *Invenergy Acquires Grain Belt Express Transmission Project.* November 2018.

[35] T&D World. *Missouri PSC Approves Purchase of Grain Belt Express Clean Line.* June 2019.

[36] US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

which comprise 17% and 19%, respectively.[37] This is despite there only being a few IOUs, compared to over 100 public utilities, and 29 co-ops. This comparison is illustrated below in Figure 13. In this section, LEI briefly discusses the major utilities in Kansas, including the IOUs, as well as the major muni and co-ops.

Figure 13. Number and retail sales by ownership (2017)

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

3.1.4.1 IOUs

There are two traditional IOUs in Kansas: Evergy and Empire District Electric.[38] The merger of Westar Energy ("Westar") and Great Plains Energy, parent of Kansas City Power & Light ("KCP&L"), created a holding company known as Evergy.[39] As filed by the utility, KCP&L operates in northeast Kansas and western Missouri, with 250,000 of its 800,000 customers located in Kansas. Westar operates in south-central and northeastern Kansas, providing electric service to approximately 700,000 retail customers.[40] Notably, Westar operates as two distinct entities in these regions. In the south-central portion, it operates as Kansas Gas & Electric ("KGE"), and in the northeast portion, it operates as Westar. As noted by KCC in its system report, although

[37] US Energy Information Administration, *Form EIA-861, Annual Electric Power Industry Report.* January 2019.

[38] Additionally, Southern Pioneer Electric Company operates as an IOU but is a wholly owned subsidiary of Pioneer Electric Cooperative. It is also under the jurisdiction of KCC. Southern Pioneer serves just over 17,200 customers in over nine counties in Southwestern Kansas.

[39] Evergy is now the largest utility in SPP, serving about 1 million customers in Kansas and nearly 600,000 customers in Missouri, controlling just over 13.7 GW of generation, or equivalent to ~13.5% of total installed capacity in the SPP market.

[40] KCC. *Electric Supply and Demand Report. Annual Report 2019.* 2019.

"*technically comprised of two separate companies, Westar's entire system is dispatched as one system unit.*"[41]

The other IOU in the State is Empire District Electric Company ("Empire"). Empire is comparatively smaller, serving under 10,000 customers in Cherokee County. Empire also operates in the states of Missouri, Oklahoma, and Arkansas, and is a wholly owned subsidiary of Algonquin Power Utilities Corporation. A map of the IOUs in Kansas is shown below in Figure 14.

Figure 14. Map of Kansas IOU service territories

Source: Commercial third-party database (Accessed on December 20, 2019)

3.1.4.2 Co-ops

Kansas is served by around 29 retail co-ops, which are responsible for 19% of all retail sales in the State and provide electricity to approximately 500,000 customers in 103 of the 105 counties.[42] Co-ops are member-owned utilities that are legally established to serve the service territory of the members. In this section, LEI provides an overview of these entities in Kansas. Figure 15 below illustrates the service territory map of these co-ops.

There are three generation and transmission ("G&T") co-ops in the State that sell power to distribution co-ops. These three co-ops are the Sunflower Electric Power Corporation

[41] KCC. *Electric Supply and Demand Report. Annual Report 2017.* 2017.

[42] Sunflower website. <https://www.sunflower.net/kansas-electric-cooperatives-turns-75/>

("Sunflower"), Mid-Kansas Electric Company ("Mid-Kansas"), and Midwest Energy Inc. ("Midwest"):

Midwest Energy Inc. ("Midwest"), the largest of the three co-ops, is a regulated electric and natural gas distribution co-op operating in central and western Kansas and provides electric service to just under 50,000 retail customers.[43] Unique in Kansas among the State's co-ops, Midwest is vertically-integrated, possessing generation and transmission assets and providing retail service.[44]

The **Kansas Electric Power Cooperative, Inc. ("KEPCo"),** which is a deregulated G&T co-op whose membership is comprised of 19 other co-ops. According to the KCC, KEPCo's 19 member cooperatives collectively serve approximately 110,000 customers, as indicated by the number of meters.[45]

Sunflower Electric Power Company ("Sunflower") is a deregulated G&T co-op owned by six-member rural distribution cooperatives in Western Kansas.[46] Notably, in 2007, the six-member distribution cooperatives comprising Sunflower formed the Mid-Kansas Electric Company ("Mid-Kansas"). Mid-Kansas was created for the purpose of purchasing the assets of Kansas Electric Network from Aquila Energy. Although Mid-Kansas has distinct assets and customers from Sunflower, the two companies employ the same individuals, and KCC has typically considered them as the same system.[47] More recently, Sunflower and Mid-Kansas received KCC's approval for their merger on March 29, 2019, and will start operating as one company on January 1, 2020.[48]

Based on EIA data, the average co-op in Kansas in 2018 served just under 11,300 customers, with a median of 7,200. An illustration of the number of co-ops is illustrated below.

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[43] KCC. *Electric Supply and Demand Report. Annual Report 2019.* 2019. P.11

[44] Ibid.

[45] KCC. *Electric Supply and Demand Report. Annual Report 2019.* 2019. P.9

[46] These member co-ops are Lane-Scott, Prairie Land, Southern Pioneer, Victory, Western, and Wheatland.

[47] See for example, in its annual electric supply and demand report. (Source: KCC. *Electric Supply and Demand Report. Annual Report 2019.* 2019).

[48] KCC. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*, KCC Docket No. 19-SEPE-054-MER.

Figure 15. Number of customers served by individual co-ops in Kansas (2018)

Source: Commercial third-party database (Accessed on December 20, 2019)

3.1.4.3 Municipal utilities

There are 118 municipal utilities in Kansas managed by local municipalities.[49] In this section, LEI provides an overview of the three largest municipal utilities by customer count, namely the Kansas City Board of Public Utilities, Garden City Electric Utility System, and Garden Utilities Department, and two municipal agencies that serve other munis. The statewide association for municipal utilities indicates that the median size of a muni in Kansas serves 832 customers.[50] The chart below illustrates the ten largest munis in Kansas by size.

[49] American Public Power Association. *Public Power in Kansas*. <https://www.publicpower.org/public-power-kansas>

[50] Kansas Municipal Utilities. *Testimony provided to the Senate Utilities Committee by Colin Hansen*. February 19, 2019.

Figure 16. Largest munis in Kansas by number of customers served (2018)

Source: Kansas Municipal Utilities. *Testimony provided to the Senate Utilities Committee by Colin Hansen.* February 19, 2019

Kansas City Board of Public Utilities ("BPU")

Established in 1909, BPU is a not-for-profit, publicly owned administrative agency of the Unified Government of Kansas City and is self-governed by an elected six-member Board of Directors. BPU provides water and electric services in Kansas City, Kansas, primarily Wyandotte County, and serves a footprint of 155.9 square miles.[51] BPU is outside the jurisdiction of the KCC and serves approximately 63,000 customers.

BPU's current facilities include three self-owned power stations, one joint-owned combined cycle, 33 substations, and roughly 3,000 miles of electric lines. The four power stations have a total capacity of approximately 785 MW.[52]

Garden City Electric Utility System ("Garden City")

As the second largest municipal utility, Garden City Electric Utility System is owned and operated by the City of Garden City in Southwest Kansas.[53] Along with water and wastewater services, Garden City provides electric utility service to just under 12,000 customers, consisting

[51] Kansas City Board of Public Utilities. *Prepared and submitted to meet WAPA IRP filling requirements of October 2019*. July 2019.

[52] Ibid.

[53] Garden City website. *Electric.* 2019.

of residential, commercial, and industrial customers. It receives transmission service from Sunflower via the SPP transmission tariff and has multiple long-term power supply contracts with Kansas Municipal Energy Agency ('KMEA") for its power supply and services related to coordination with SPP. [54] Garden City also owns a 27 MW simple cycle gas generation plant, which, combined with its firm capacity purchases, allows it to meet its peak demand, which exceeded 77 MW in 2017.[55]

Gardner Utilities Department ("Gardner")

Gardner serves the entire City of Gardner in northeast Kansas, with a population of over 21,000 and just over 8,600 customers. The muni meets most of its supply needs through supply contracts from other utilities, including Omaha Public Power District and Evergy.[56] Gardner also owns and operated a 15 MW combustion turbine plant, consisting of two peaking units.[57] The purchased and generated power is transmitted into the ten square mile service territory over four miles of high voltage transmission lines. The distribution lines total around 103 miles, most of which are underground lines.[58]

Kansas Municipal Energy Agency

KMEA, a joint-action, quasi-municipal corporation established in 1980 by a group of cities under the authority of Kansas statutes, serves the purpose of securing an adequate, economical, and reliable supply of electricity and other energy, and transmitting the energy to the distribution systems of its member cities.[59] Put another way, KMEA finances projects for the purchase, sale, generation, and transmission of electricity on behalf of its member municipal electric utilities, as well as managing the Mutual Aid program where municipalities assist one another in the event of emergencies. As of 2018, KMEA has 77 member cities and nine elected directors on its board, which governs the business affairs of the KMEA. KMEA supplies its customers through an installed capacity of 425 MW.[60]

Kansas Power Pool ("KPP")

Established under Kansas statutes in 2004, KPP is an organization that provides wholesale electric power, reserve sharing, collective resource planning and acquisition, network transmission

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[54] Krajewsky, J. *Review of Capacity Alternatives. Report to the City of Garden City.* March 2017.

[55] Ibid.

[56] City of Gardner website. *Electric Generation and Substations.* 2019.

[57] Ibid.

[58] City of Gardner website. *Electric Distribution.* 2019.

[59] Kansas Municipal Energy Agency. *Annual Report*. 2018

[60] Kansas Corporation Commission. *Electric Supply and Demand Annual Report*. 2019

service, and cost-sharing of operations to its member municipal utilities.[61] KPP provides wholesale capacity, energy, and transmission services for its members, and is responsible for a total system capacity of approximately 335 MW, which comprises both long-term power agreements, resources from member generation, and KPP-owned plants.

Municipalities who are supplied by KPP are subject to a power purchase contracts with a 20-year term, referred to as the KPP Amended Operating Agreement.[62] By the end of 2017, KPP had 24 full-service members, 23 of whom are bound to the KPP with a power purchase contract for all of their wholesale energy needs through to 2032. The KPP also provides transmission services for all members through Southwest Power Pool as part of KPP's Network Integrated Transmission Service. Sixteen of KPP's members are in Evergy's transmission zone, while seven are in the Mid-Kansas Electric Company zone, and one is in the Midwest Energy zone.[63] An illustration of KPP's relationship with other industry actors is shown in Figure 17.

Figure 17. Overview of Kansas Power Pool

Source: Kansas Power Pool; LEI analysis

3.2 Institutional arrangements

Key institutions include the Kansas Corporation Commission, the Kansas Energy Office, the Legislative Coordinating Council, as well as the Citizens Utility Ratepayer Board. Each is described in greater detail below.

[61] Ibid.

[62] Kansas Power Pool. *The Kansas Power Pool, A Municipal Energy Agency*. 2018

[63] Kansas Power Pool. *Direct Testimony and Exhibits of Larry Holloway. Docket No 17-KPPE-092-COM.* August 2017.

3.2.1 Kansas Corporation Commission

In 1911, the Kansas Legislature created the Public Corporation Commission, now the KCC, to regulate telegraph, pipeline, common carriers, water, electric, gas, and power companies with the exception of municipal utilities.[64] The KCC consists of three Commissioners appointed by the Governor to staggered four-year terms.

The KCC is the primary regulatory body for the electric industry in Kansas and has a mandate from Kansas statutes to perform its responsibilities. KCC's Utilities Division establishes and regulates rates for public utilities, which includes electricity, natural gas, liquid pipelines, and telecommunications. It derives its mandate from the statutes K.S.A. 74-601 to K.S.A. 74-631, and any appeals to its decisions may be heard by the Kansas Court of Appeals. According to the laws stipulated in Kansas Statute 66-101 et seq., the KCC is "*given full power, authority and jurisdiction to supervise and control the electric public utilities as defined in K.S.A. 66-101a, doing business in Kansas and is empowered to do all things necessary and convenient for the exercise of such power, authority, and jurisdiction.*"[65] A summary of these specific responsibilities is described below:

- ***Economic regulation***: Consistent with Kansas statutes, the KCC determines and oversees the ratemaking process for all-electric public utilities defined in K.S.A. 66-101a, and these utilities are required to obtain KCC's approval for any changes to their rates and/or terms of service. A discussion of how a public utility is defined in Kansas is summarized in the textbox below. Under K.S.A. 66-101b, KCC is responsible for ensuring that all public utilities establish "just and reasonable" rates that are necessary to maintain "reasonably sufficient and efficient service."[66] It is important to note that outside the KCC's mandate are most electric cooperatives, water cooperatives, municipalities, wireless telephone, long-distance service, cable companies, or the internet service providers.
- ***Transmission siting and permitting***: KCC is also responsible for siting and permitting of transmission lines, as defined in Section 3.1.2 A KCC permit is required before a utility can begin site preparation, construction of the line, or exercise the right of eminent domain.[67]
- ***Regional transmission organization and FERC representation***: KCC represents Kansas at the RTO as mandated by K.S.A. 74-633. Kansas utilities are members of SPP, and the KCC is authorized to "*participate fully in all decision-making bodies of such regional transmission organization, whether the decision of such bodies are advisory to or binding on the regional transmission authorization*."[68] To this end, KCC has staff participate in various committees

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[64] Kansas Corporation Commission. About the KCC. <https://kcc.ks.gov/about-us/the-commissions-s-role>

[65] Kansas Statutes K.S.A. 66-101. *Electric public utilities; power, authority and jurisdiction of state corporation commission.*

[66] Kansas Statutes K.S.A. 66-101b. *Electric public utilities; efficient and sufficient service; just and reasonable rate.*

[67] Kansas Statutes K.S.A. 66-1178. *Same; siting of electric transmission lines; permit required; application, contents; hearings.*

[68] Kansas Statutes K.S.A. 74-633. *Representative to regional transmission organization, authority.*

and working groups in SPP. Similarly, KCC will also intervene on behalf of Kansas customers at proceedings at FERC and is authorized to participate on their behalf.

- ***Monitoring and reporting***: the KCC regularly requires utilities to report annually to it on a number of issues for monitoring purposes. Its mandate is derived from K.S.A. 66-123, which allows it to require utilities furnish it with periodic reports as necessary.[69] An example of this is the Electric Supply and Demand Report, under K.S.A. 66-1282, which requires the KCC to compile a report regarding supply and demand in the State, including information on generation capacity needs, peak capacity needs and renewable needs.[70]

According to the laws stipulated in Kansas Statute 66-101 et seq., the KCC is "*given full power, authority and jurisdiction to supervise and control the electric public utilities as defined in K.S.A. 66-101a, doing business in Kansas and is empowered to do all things necessary and convenient for the exercise of such power, authority, and jurisdiction.*"[71] Therefore, the KCC determines and oversees the ratemaking process for all-electric public utilities defined in K.S.A. 66-101a (and listed in the textbox below), and these utilities are required to obtain KCC's approval for any changes to their rates and/or terms of service.

Defining a public utility in Kansas

Kansas statutes K.S.A 66-104 define a "public utility" that is subject to KCC jurisdiction as any entity that "*may own, control, operate or manage, except for private use, any equipment, plant or generating machinery, or any part thereof, for … the conveyance of oil and gas through pipelines in or through any part of the state, except pipelines less than 15 miles in length and not operated in connection with or for the general commercial supply of gas or oil, and all companies for the production, transmission, delivery or furnishing of heat, light, water or power*" in the state of Kansas. Under these statutes, and under the oversight of the commission, public utilities are required to provide "*reasonably efficient and sufficient service*" as well as to charge "*just and reasonable rates*".

Consistent with regulation in other jurisdictions, co-ops and munis are exempted from regulatory oversight, with few exceptions. One notable exception applies to municipal utilities that provide utility service for customers outside the corporate limits of the municipality. In this exception, KCC regulation may apply if these customers comprise more than 60% of the municipality's total number customers.

Source: Kansas Statutes. *66-104. Utilities subject to supervision; exceptions;* Kansas statutes. *66-104f. Jurisdiction over municipal electric or natural gas public utilities; limitations*.

KCC's Utilities Division establishes and regulates rates for public utilities, which includes electricity, natural gas, liquid pipelines, and telecommunications. It derives its mandate from K.S.A. 74-601, and any appeals to its decisions may be heard by the Kansas Court of Appeals. For the electric public utilities, KCC has jurisdiction over Westar Energy, KCP&L, Empire District,

[69] Kansas Statutes K.S.A. 66-123. *Public utilities and common carriers, reports; penalty for failure to file.*

[70] Kansas Statutes K.S.A. 66-1282. *Electric supply and demand reports.*

[71] K.S.A. 66-101. <https://www.ksrevisor.org/statutes/chapters/ch66/066_001_0001.html>

and Southern Pioneer Electric Company. Co-ops and munis generally do not fall under the jurisdiction of the KCC in terms of rate setting.

The KCC is also a member of the SPP RSC. The RSC provides state regulatory agency input on regional matters related to the development and operation of high voltage transmission, and its membership includes one designated commissioner from each state regulatory commission that has jurisdiction over an SPP member.[72] The RSC also oversees SPP's Cost Allocation Working Group and is a critical function of SPP governance. The RSC exercises this authority through its evaluation of the extent to which participation funding in SPP will be used for transmission enhancements, and if license plate or postage stamp rates will be used for regional access charges.[73] Under a license plate approach, transmission rates vary according to region or area within which the service is provided, whereas a postage stamp approach entails all entities paying the same rate, regardless of geographical location.

LEI understands that KCC has 37 full-time equivalent ("FTE") staff positions within the Utilities Division divided into four sections, i.e., Accounting and Financial Analysis, Economics and Rates, Energy Operations, and Pipeline Safety, and Telecommunications.[74,75]

3.2.2 Kansas Energy Office

The Kansas Energy Office is a division of the KCC, with its primary mandate being the administration of programs and provision of educational information to customers on "conservation, efficiency, and alternative energy."[76] The office is funded through the US Department of Energy ("DOE") State Energy Program and fulfills its mandate through a partnership between KCC staff and the Kansas State University.

3.2.3 Legislative Coordinating Council

The Legislative Coordinating Council ("LCC") is a standing committee of the state's Legislature. It is a body created by state law to "*represent the legislature when the legislature is not in session*."[77] Most importantly, it is responsible for governing "*the mechanics and procedure of all legislative committee work and activities*" during this period.[78] It is comprised of the leadership of the

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[72] Southwest Power Pool. *The History of The Regional State Committee for the Southwest Power Pool, Inc. 2019 Version.* April 29, 2019.

[73] Ibid.

[74] KCC. *Utilities and Common Carriers. Annual Report 2019.* 2019.

[75] Kansas Legislative Research Department. *Budget Analysis: State Corporation Commission.* 2019.

[76] KCC website. *Kansas Energy Office.* Accessed at: <https://kcc.ks.gov/kansas-energy-office>

[77] Kansas Statutes. 46-1202. *Legislative coordinating council; general powers and functions; rules; majority vote of five members required, exceptions.* Accessed at: <https://www.ksrevisor.org/statutes/chapters/ch46/046_012_0002.html>

[78] Ibid.

bicameral houses, with a membership of seven, including the President of the Senate, the Speaker of the House, the Speaker *pro tem* of the House, the Majority Leaders of the Senate and the House, and the Minority Leaders of the Senate and House.[79]

3.2.4 Citizens Utility Ratepayer Board

The Citizen's Utility Ratepayer Board ("CURB") is an independent agency and the consumer advocate in Kansas. CURB was created in 1989 as part of KCC but has been separated from the regulator since 1993. Its mandate is "*to protect the interests of residential and small commercial utility ratepayers in the state of Kansas by providing them with competent, quality legal representation before the KCC, the Courts, and the Legislature*."[80] It performs this role by representing ratepayers, initiating, and intervening in rate cases, as well as requesting rehearing or review of KCC orders.[81] CURB is funded by assessments that are levied against public utilities in whose cases CURB has intervened.

In addition to its five-member volunteer board appointed by the Governor, CURB currently has six FTE positions, including a consumer counsel, two supporting attorneys, two technical analysts, and two administrative staff.[82] CURB also frequently relies on consultants to review technical issues in which it has intervened.

3.3 Electricity rates in Kansas

Electricity rates in Kansas are a point of contention in the State, as evidenced by the recent rate studies undertaken by the KCC staff and Evergy. The concern surrounds the competitiveness of Kansas electricity rates compared to other regional states. The average electricity price in Kansas was slightly higher than the average regional electricity rates for the region (at $0.080/kWh compared to the regional average of $0.079/kWh) in 2009, as shown in Figure 18 below. However, by 2018, Kansas had the highest average electricity rates among the neighboring states. In terms of electricity price increase, the average electricity rates in Kansas grew by an average of 3.33% per year during this period. This average electricity rate growth is the same as the increase in other states such as Missouri (3.40%), North Dakota (3.34%), and South Dakota (3.38%).

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[79] Kansas Statutes. 46-1201. *Legislative coordinating council; membership; officers; meetings; notice of meetings to members of legislature and certain legislative officials.* Accessed at: <https://www.ksrevisor.org/statutes/chapters/ch46/046_012_0001.html>

[80] CURB website. *About Us. Meet our Staff.* Accessed at: <http://curb.kansas.gov/about.htm>

[81] Kansas Legislative Research Department. *Citizens Utility Ratepayer Board.* 2017.

[82] CURB website. *About Us. Meet our Staff.* Accessed at: <http://curb.kansas.gov/about.htm>

Figure 18. Average electricity rates in Kansas and regional states (2009 and 2018)

Year	Kansas	Arkansas	Colorado	Iowa	Missouri	North Dakota	Oklahoma	South Dakota	Texas	Regional average
2009	$ 0.080	$ 0.076	$ 0.083	$ 0.074	$ 0.074	$ 0.066	$ 0.069	$ 0.074	$ 0.099	$ 0.077
2018	$ 0.107	$ 0.078	$ 0.100	$ 0.089	$ 0.099	$ 0.089	$ 0.081	$ 0.100	$ 0.085	$ 0.090
CAGR	3.3%	0.3%	2.1%	2.1%	3.4%	3.3%	1.7%	3.4%	-1.7%	1.8%

Note: Regional average is the average price of the comparator states, i.e., Arkansas, Colorado, Iowa, Missouri, North Dakota, Oklahoma, South Dakota, and Texas.

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

Figure 19. Average electricity rates in Kansas by customer type (2009-2018)

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019; St. Louis Federal Reserve. *Federal Reserve Economic Data.*

In terms of average electricity rates by customer type, residential customers in Kansas have higher electricity rates than commercial and industrial customers, as shown in Figure 19. This is normal and reflects underlying load patterns. In terms of electricity growth, residential customers' electricity rates also increased the most in the past ten years by an average of 3.82% per annum compared to 3.43% and 2.47% per year for commercial and industrial customers, respectively. The increase in electricity rates in Kansas can be attributed to several key drivers, namely, flattening demand, investments in environmental retrofits at fossil fuel-fired plants to meet federal regulations, and increasing transmission costs. These key factors are discussed briefly below.

3.3.1 Flattening demand

One of the drivers for rising rates that was cited by the utilities in their rate study was flattening electricity consumption, both in its service territory and in the US.[83] In the past five years, retail sales amongst various customer classes have flattened, with load growth averaging just over 1%. This load growth is the smallest among residential customers at 0.9% (and even lower over ten years), due to increased energy efficiency and declining energy intensity per customer. Load growth is shown in Figure 20 below.

Figure 20. Retail sales in Kansas by customer class (2009-2018)

Source: US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report*. January 2019

[83] Westar Energy & Kansas City Power & Light Co. *Kansas Rate Study. Exhibit A. Docket No. 19-KCPE-053-CPL.* January 2019.

3.3.2 Environmental retrofits

Following the introduction of more stringent air quality standards for power plants in 2007, Kansas's electric utilities spent just under $2.5 billion in environmental retrofits for their thermal fleets.[84] As discussed in Section 3.1.1, a significant amount of Kansas' generation fleet is coal-fired and also aging. Specifically, $1.85 billion was spent by Westar Energy, and $617 million by KCP&L in capex to meet air quality standards introduced by the Environmental Protection Agency.[85] Most notably were the investments made to meet the Mercury and Air Toxics Standards rule, and the Cross-State Air Pollution Rule.[86]

3.3.3 Transmission costs

Utilities and KCC staff also cited increased transmission investments resulting from SPP-directed transmission expenditure as a driver for increased rates. Also, the transmission delivery charge ("TDC") is a charge passed on to customers to recover SPP-assessed service for the utility's retail load. Section 4.2.5.3 will discuss in detail the TDC. The TDC is based on the SPP Annual Transmission Revenue Requirement ("ATRR") described in Section 4.2.3, and KCC staff have noted that it includes a higher return on equity ("ROE") than those allowed by the regulator.[87] Section 4.2.3 discusses in detail how transmission costs are determined.

According to the retail rate studies conducted by the KCC and the Evergy utilities, the impact of key factors driving the rise in rates was quantified. KCC staff analysis indicated that 60% of Westar's rate increases were driven by environmental retrofits and transmission investments.[88] For KCP&L, environmental retrofits, transmission charges, and increased power production costs were responsible for 62% of rate increases.[89]

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[84] Kansas Corporation Commission. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018.* December 2018.

[85] Ibid. P. 37.

[86] Westar Energy & Kansas City Power & Light Co. *Kansas Rate Study. Exhibit A. Docket No. 19-KCPE-053-CPL.* January 2019. P. 49.

[87] Kansas Corporation Commission. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018.* December 2018. P. 55.

[88] Ibid. P. 14.

[89] Ibid. P. 15.

Key takeaways: Overview of Kansas electricity industry

- Electric generation installed capacity in Kansas is dominated by coal, gas, and wind resources. All Kansas utilities belong to an RTO i.e. SPP which controls and manages the utilities' transmission assets. Kansas has an unusually high number of entities involved in electricity retail, including a total of around 150 IOUs, co-ops, and munis.

- The KCC is the state regulatory authority responsible for overseeing the sector, with direct oversight of the IOUs (and Pioneer Electric).

- Electric rates in the state have increased above the regional average over the last decade, driven by a number of factors including flattening demand, rising transmission costs, and environmental retrofits.

4 Ratemaking practices of electric utilities in Kansas

There are three types of electric utilities operating in Kansas, namely IOUs, munis, and co-ops, as discussed in Section 3.1.4. These utilities have different business models, governance and oversight structures, and profit motivations. Figure 21 below provides a summary of the key differences between these three utility types. IOUs generally operate for-profit and are owned by shareholders while the co-ops and munis are not-for-profit entities and are owned by the municipality (in the case of munis) or the members (in the case of the co-ops).

Figure 21. Summary of electric utility types

	Investor-Owned	Municipal	Cooperative
Business model	For-profit, shareholder owned	Not-for-profit, community-owned	Not-for-profit, member-owned
Governance	Board of Directors	Elected/appointed boards, mayors, city council members	Member-elected boards
Regulation	State utility commission	Local/state government	Self or state utility commission for some co-ops
Taxes	Pays taxes to local government	Exempt from most taxes; instead makes payments in lieu, or transfers to a general fund	May neither pay taxes nor make other contributions to local government
Degree of Customer Influence	Indirect, structured through utility oversight	Semi-direct, leadership elected or appointed by political leaders	Direct elections of utility board members
Profit motivation	For profit	Profits partly fund city budget	Returns profits to members

Source: LEI analysis

IOUs, which generally have greater access to capital markets allowing them to make larger investments, are overseen by regulators that approve their rates and activities. They also report to a board of directors that has a fiduciary duty to its shareholders. On the other hand, munis are led by elected and/or local government officials or an independent board. Munis may finance their activities with government bonds and are often exempt from most taxes. Finally, co-ops are usually exempt from state regulation and have access to federal financing programs.

This section presents the ratemaking process and determination of the revenue requirements for IOUs, co-ops, and munis in the State. The commonly accepted guiding principles in the ratemaking process, together with specific items mentioned in the Sub. for SB 69 will be used to assess the effectiveness of the ratemaking practices in the State, are also briefly discussed.

4.1 Guiding principles in the ratemaking process

A prudent ratemaking process aims to ensure the provision of reliable electric service at a just and reasonable cost to consumers. To effectively implement such a process, a regulator ought to consider and adequately balance the interests of utilities, with respect to cost recovery and reasonable return on capital investment, and consumers with regard to fair and affordable rates and reliable service. Also, according to the foundational principles identified by James C. Bonbright, rates should have practical attributes including "simplicity, understandability, public acceptability, and feasibility of an application."[90] In general, broadly accepted principles of ratemaking can be categorized into six groups:

1. ***Economic efficiency and performance***: Provide funding to maintain reliability consistent with customer expectations while recognizing such preferences are increasingly varied.
2. ***Customer focus and bill impacts***: Encourages the pursuit of opportunities for better cost containment.
3. ***Stability of the sector***: Investment signals must be proportional to associated risk, and market returns and remuneration should take into account the impact on debt service coverage ratios and associated parameters for maintaining an efficient capital structure. Also, stranded costs should be identified, quantified, and recovered in a fair manner
4. ***Cost causation and avoidance of cross-subsidies:*** One of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross-subsidies (either between or within customer classes) could be avoided.
5. ***Evolving utility structure to facilitate innovation***: Framework must balance incumbent opportunities against market participation, reducing barriers to the third-party providers of services. This also includes the elimination of capex, ownership, and technology biases and emphasizes the focus on a long-run least-cost approach that values optionality for determining solutions to identified system and customer needs.
6. ***Regulatory simplicity***: Ratemaking must balance appropriate oversight with administrative simplicity to avoid an overly burdensome process for all parties. Moreover, the framework must have built-in decision criteria and evaluation to increase accountability and advance strong stakeholder support.

Kansas statutes regarding public utilities closely align with the principles summarized above. According to K.S.A. 66-101b, all-electric public utilities in Kansas are required to "establish and maintain just and reasonable rates" and "maintain reasonably sufficient and efficient service."[91] The principles outlined in K.S.A. 66-101b apply to all the three types of electric utilities in Kansas, including IOUs, cooperative utilities, and municipal utilities.

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[90] Bonbright, James C., Principles of Public Utility Rates, Columbia University Press, New York NY, 1961.

[91] K.S.A. 66-101b. <https://www.ksrevisor.org/statutes/chapters/ch66/066_001_0001b.html>

In addition to these guiding principles, LEI will evaluate the effectiveness of the current ratemaking practices for IOUs in terms of the items specified in the substitute for SB 69, namely:

- the ability of IOUs to attract needed utility capital investment and adequately discourage unnecessary capital investments in Kansas;
- the ability of IOUs to appropriately balance utility profits with public interest objectives of achieving competitive rates over time while providing the best practicable combination of price, quality, and service; and
- the extent to which IOUs recover from Kansas retail electric ratepayers the full or partial cost, including a return on investment, of any investments no longer fully used or required to be used in service to the public within Kansas, including but not limited to, generation capacity investments.

For the co-ops and munis, the Sub. for SB 69 specified that the ratemaking processes should be evaluated based on whether they are in the public interest.

4.2 Investor-owned utilities

IOUs are a form of ownership in which a utility is owned by shareholders and operated to generate profit. An IOU can be publicly traded or privately held. In the case of Kansas, Evergy, which is the parent company of the two largest IOUs in Kansas (Westar and KCP&L), is publicly traded while Empire District is privately held.[92]

IOU management reports to a board of directors, which has a fiduciary duty to its shareholders. Management, in turn, responds to signals from its regulators regarding priorities. Generally, IOUs are required to provide reliable service consistent with good utility practice by making prudent investments. Provided they have done so consistently with prevailing regulations, they are entitled to a fair return on their regulated asset base. One way for IOUs to increase profits is to pursue additional capital investments. While regulators have attempted to change incentives by redesigning rates, IOUs are conditioned to plan according to a return on rate base – if rate base is not growing, it is more difficult for profits to grow.[93]

IOUs in Kansas are required to obtain KCC's approval for any rate adjustments they wish to implement.

4.2.1 Ratemaking process

For the IOUs, KCC has jurisdiction over the ratemaking process for generation and distribution, while transmission ratemaking is based on FERC-authorized transmission formula rates ("TFR") via SPP.

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[92] Empire District's parent company, Algonquin Power & Utilities Corp., is a publicly traded company.

[93] Cost of service ("COS") is the starting point for all regulatory frameworks for regulated utilities. PBR regimes build upon COS principles, including calculation of rate base, target fair returns, and cost allocation studies.

To authorize rates that are fair, reasonable, and beneficial to the public, the KCC follows a series of six steps in its ratemaking process, as summarized in Figure 22 below. This process is relatively standard and is used in many US jurisdictions. The process starts when a utility files an application to the KCC requesting changes to rates and/or terms of service. The application typically includes details on the proposed changes, relevant supporting data, and testimony.

Upon the receipt of an application, the KCC staff then reviews the filings and, if necessary, requests additional information from the given utility before providing a "non-binding recommendation" to the KCC's three commissioners. Also, the KCC allows relevant stakeholders (also referred to as intervenors) such as representatives of consumers and industrial groups to file their recommendations regarding the given case. The CURB, which is the state-appointed representative of residential and small commercial ratepayers, typically intervenes in rates cases presented before the KCC on behalf of residential and small commercial ratepayers.[94]

Figure 22. Ratemaking process in Kansas

While not required by law, in certain "significant rate cases," the KCC conducts a public hearing which invites relevant stakeholders to learn more about the proposed changes, ask questions, and provide their comments and views on a given case.[95] Statements made during the hearing are formally filed in the case docket and later considered by KCC's commissioners in the decision-making process. The KCC may also hold an evidentiary hearing in which expert witnesses, whose

[94] KCC. "The Utility Ratemaking Process." <https://kcc.ks.gov/electric/how-rates-are-set>

[95] Please note that a public hearing is required by law in the event that a utility requests approval to construct or alter transmission lines greater than 230 kilovolts and more than five miles in length. In addition, cases involving proposed rules and regulation also required public hearing.

written testimonies are filed, testify and respond to questions from the commissioners, CURB, and other intervenors. Following a thorough review of all the records, case facts, and legal briefs, the KCC commissioners then announce a final decision through a written order in an open business meeting.

In Kansas, however, many rate case proceedings are resolved by settlements following the review process (Step 2). According to a report from the KCC, "fully litigated cases are a minority of the total large investor-owned rate case to appear before the Commission."[96] Settlement agreements resulting from negotiations between the KCC staff, the given utility, the CURB, any relevant intervenors, and the KCC may choose to accept, reject, or modify any settlement agreement. Of the rate cases the KCC has reviewed to date, only three were fully litigated while the remaining were decided upon through a settlement.[97] The textbox below provides more detailed information as to the rate cases of the IOUs for the past ten years.

Stakeholders' view on settlements

According to an IOU representative, settlements are more efficient than lengthy rate case processes since they still allow all relevant parties to converse and come to an agreement. He emphasized that:

- settlements are not as simple as some deem them to be given that participating parties must compromise with all the parties at the table;
- settlements might become more complicated in the future especially with more contentious issues and more intervenors arising; and
- with settlements, the issues that were conceded were not discussed and thus, the utilities do not know how the KCC would have responded.

Source: Meeting with the stakeholders; September 30, 2019, Topeka, Kansas

A rate case settlement is not unusual in the region. Although Figure 23 shows that Kansas had a relatively higher percentage of settled rate cases compared to its neighboring states, the data also shows that all of these states have settled at least half of the rate cases in the past ten years. Kansas, Missouri, and Texas had the most settled rate cases among these seven states.

In terms of the duration of the rate case process, it takes, on average, seven months in Kansas. This is lower than the average time it takes for the region, as shown in Figure 23 below. It is interesting to note that although North Dakota had all its rate cases settled, it also took the most time to complete a rate case at almost a year (Figure 24). A shorter rate case process means lower regulatory burden for the regulator and the utility and customers.

[96] KCC. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018. Page 51. <https://kcc.ks.gov/images/PDFs/electric/Rate-Study-Final-1-13-2018.pdf>

[97] S&P Global Market Intelligence. Rate Case History (Kansas).

Figure 23. Settled vs. fully litigated rate cases in Kansas and surrounding states for the past ten years

State	Fully Litigated	Settled	% of settled to total rate case
Colorado	4	5	56%
Iowa	2	2	50%
Kansas	3	15	83%
Missouri	10	15	60%
North Dakota		6	100%
South Dakota	2	7	78%
Texas	5	15	75%

Source: Commercial third-party database (Accessed on November 8, 2019)

Figure 24. Average duration (in months) of rate cases for the past ten years

Source: Commercial third-party database (Accessed on November 8, 2019)

4.2.2 Revenue requirements for generation and distribution

The KCC follows a ratemaking methodology that aims to implement "just and reasonable" rates that ensure the provision of "efficient and sufficient" services by utilities.[98]

The revenue requirement identifies the expected amount of revenue a utility requires to cover its cost of service, allowed return to its investors, and operating costs.[99] The revenue requirements have three key components, namely the rate base, the Rate of Return ("ROR"), and operating costs. These components are discussed in detail in the succeeding subsections. The revenue requirement is determined by multiplying the rate base by an appropriate ROR and adding the operating costs, as shown in Figure 25. Under this basic calculation, utilities do not earn a return on operating costs, as these costs are passed on to ratepayers.[100]

Figure 25. Revenue requirements formula for an IOU

Note: There are also pass-through charges, such as fuel cost adjustment riders. These are discussed in Section 4.2.5.

4.2.2.1 Rate base

When beginning to analyze a given utility's revenue requirement, the KCC staff selects a historical test year (12-month period) to use as a baseline for examining the given utility's actual revenues and expenses.[101]

The rate base is comprised of investments made by the utility to provide electric service and includes such items as utility-owned generation facilities, buildings, poles, wires, transformers, meters, vehicles, and computers. The rate base is the investment base to which a ROR is applied to arrive at the allowed return to investors. Accordingly, material increases in the rate base, due to additional capital investment, can result in a significant increase in the utility's overall revenue requirement.

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[98] KCC. How rates are set. <https://kcc.ks.gov/electric/how-rates-are-set>

[99] Revenue requirements are typically estimated beforehand and may not reflect the actual cost of service. Large fluctuations in fuel prices or a natural disaster may impact the costs incurred by the utility, which may lead to an adjustment in subsequent years.

[100] Operating costs include fuel costs, purchase power expenses, other operations and maintenance ("O&M") costs, depreciation, and taxes

[101] KCC. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018. <https://kcc.ks.gov/images/PDFs/electric/Rate-Study-Final-1-13-2018.pdf>

In general, the components of the rate base include the net cost of plant in service,[102] inventories of fuel and other materials, and regulatory assets.[103]

At a high level, the rate base at the end of a year is calculated as the sum of the net book value of physical and regulated assets at the beginning of the year, plus the annual capex, and minus the annual depreciation /amortization of assets, as illustrated in Figure 26. In determining the rate base, the KCC allows the inclusion of new plants that are "used and required to be used" to provide "efficient and sufficient" services to consumers.[104] The KCC also removes from the rate base the plants that no longer provide services to consumers.

Figure 26. Rate base formula

The rate base of the IOUs has been increasing for the past ten years. For instance, Westar Energy's ratio of rate base to the total number of customers increased by approximately 37.8% per year between 2012 and 2018, as shown in Figure 27 below. This is due to a combination of factors including investments in renewable generation investments (specifically, wind), and the expiration of wholesale agreements.[105] The increase can be attributed more to the rise in the rate base (41.5% per year) as its total number of customers only grew by an average of 2.7% per year. Figure 27 below illustrates the ratio of Westar Energy's rate base to the total number of customers over the last ten years.

KCP&L's ratio of rate base to the total number of customers increased by approximately 20.8% per year between 2010 and 2018, as shown in Figure 28 below. This increase in rate base can be attributed to additional investments in plant and infrastructure, which included the addition of

[102] The net cost of plant in service, which is the book value of the physical assets owned by the utility such as generation plants, transmission, and distribution ("T&D") infrastructure, vehicles, land, and office buildings and supplies. It is typically by far the largest component of rate base.

[103] Regulatory assets created when regulators allow the utility to move certain costs from its income statement to its balance sheet.

[104] KCC. "The utility ratemaking process." <https://kcc.ks.gov/electric/how-rates-are-set>

[105] Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service. Docket No. 18-WSEE-328-RTS. <http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20180201153235.pdf?Id=b22acea6-0fe8-48a3-9cba-fd693b7ad461>

a new Customer Information System.[106] During the same period, KCP&L's total number of customers increased by only 7.1% per annum, while its rate base increased by approximately 30.6% per annum.

Figure 27. Westar Energy Rate base per customer (2009-present)

Note: Only years in which rate base changes occurred are included in the graphic (namely, 2012, 2013, 2015, 2017, and 2018).

Source: Data acquired through a data request response from Evergy.

Figure 28. KCP&L Rate base per customer (2009-present)

Note: Only years in which rate base changes occurred are included in the graphic (namely, 2010, 2012, 2014, 2017, and 2018).

Source: Data acquired through a data request response from Evergy.

[106] Application for KCP&L Rate Case. Docket No. 18-KCPE-480-RTS <http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20180501162757.pdf?Id=78094501-bdab-4036-bee9-a1cd37fc2311>

The rate base to customer ratio for both Westar and KCP&L is significantly above the average for the region. As shown in Figure 29 below, the rate base per customer ratio for Westar and KCP&L is 92% and 23% above average, respectively. But it should be noted that the timing of capital investments can vary across utilities. The graphic below shows a specific period of time and should not be taken as the case for all the years.

Figure 29. Rate base per customer for Westar, KCP&L, and surrounding regions (2017/2018)

State	Utility	Rate base per customer	# of customers	Population density (state)
North Dakota	Otter Tail Power Company	2,784	131,047	11.0
Colorado	Public Service Company of Colorado	5,069	1,459,116	52.6
Texas	Entergy Texas, Inc.	5,676	453,043	104.9
Missouri	Evergy Missouri West, Inc.	5,841	326,627	88.3
Iowa	Interstate Power and Light Company	8,731	489,605	55.9
Kansas	KCP&L	8,977	259,099	35.6
Kansas	Westar	14,009	381,420	35.6

Source: Rate base data provided by Evergy from LEI's data request and number of customers and population density from a third-party commercial database.

Retail sales for the past few years were not growing as fast as the IOUs' rate base. Between 2010 and 2018, residential load declined by approximately 1%, while commercial and industrial load increased by 4.7% and 9.7%, respectively, while the rate base grew about 16.5 times, as shown in Figure 30 below. Some stakeholders are proposing to encourage large industrial customers to

come to Kansas to spread the costs of service. Section 6.3 provides a discussion on this potential option.

Figure 30. Retail sales (load growth) vs. rate base for Kansas IOUs

Note: The rate base values are aggregated across the three Kansas IOUs (Westar Energy, KCP&L, and Empire District) for the specific years in which the utilities had a rate case. Starting in 2012, the values represent the sum of the incremental rate base from the previous year and the rate base for the given year.

Source: Data provided by the utility from LEI's data request.

4.2.2.2 Rate of return

The second component of the revenue requirements is the **allowed rate of return**. This is expressed as a percentage and essentially represents the amount of return that investors will receive on their investment, the asset base. Setting the allowed rate of return requires balancing two equally important objectives: incentivizing continued investment in the sector and ensuring that consumers pay just and reasonable rates. There is ultimately no single correct allowed rate of return but rather a "'zone of reasonableness' within which judgment must be exercised.

The predominant method for setting the allowed rate of return is to use the regulated utility's weighted average cost of capital ("WACC").[107] WACC is the total cost, in percentage terms, of financing the utility's assets. Accordingly, the KCC uses the WACC to determine the appropriate

[107] There are a number of methods that could be used to set rates of return for a utility. Historical rates, "a priori" (model-based), and the WACC have all been used by financial practitioners in determining what the rate of return should be for an investment. Each of these could be applied to determine what return the utility should be allowed to make, in order to provide enough incentives for investment. It must be noted that, of these three methods, only WACC is in common use in utility rate setting, although historical rates are sometimes used to set parameters utilized in estimating WACC.

rate of return for IOUs in Kansas.[108] In this approach, the allowed rate of return is set equal to the utility's WACC, suggesting that the utility is being compensated for a return on its capital costs. This implies that the utility will make a nominal but not an economic profit.

To calculate the WACC, a number of inputs are required: the cost of equity, the cost of debt, and the capital structure to be used. It is calculated as:

$$WACC=[D\times R_D] + [(1-D)x\ R_E]$$

Where D=ratio of debt to assets, R_D=cost of debt (after-tax), and R_E=cost of equity

The KCC approves an appropriate ROE value for a utility after evaluating testimony from multiple witnesses to ensure that the ROE reflects the specific risks associated with investing equity in the given utility. This is called the "authorized ROE," and it is specified in the rate case of the utility.

The authorized ROE is then used to calculate the overall return that is applied to the utility's rate base and reflected in the rates that customers are charged.[109] On the other hand, the "earned ROE" is the actual results achieved by the utility over a period of time. The ROE is the portion of the revenue requirement that a utility keeps as profit. The IOUs' requested and authorized ROEs have declined for the past few years. KCC authorized ROEs decreasing from 10% in 2010 to 9.3% in 2018. Figure 31 below shows these requested and authorized ROEs in Kansas.

In *Bluefield Water Works & Improvement Company v. Public Service Comm'n, 262 US 679, 692* (1923), the Court stated that the ROE "assures confidence in the utility's financial soundness, supports the utility's credit, and enables it to raise the money sufficient to perform its obligations."[1] According to the body of law followed by the KCC, the appropriate ROE ought to have the following characteristics:

"(1) be commensurate with returns on investments of similar risk;

(2) be sufficient to assure the financial integrity of the utility under efficient economic management; and

(3) change over time with changes in the money market and business conditions."

Source: Bluefield Water Works v. Public Service Comm'n, 262 US 679 (1923). Argued: January 22, 1923. Decided: June 11, 1923

Kansas' average, historical ROE between 2010 and 2019 is slightly below average compared to surrounding states. As shown in Figure 32 below, the average ROE for Kansas is approximately 3.3% lower than the regional average. Kansas has the second lowest ROE among the regional states, next only to South Dakota.

[108] KCC. "The utility ratemaking process" <https://kcc.ks.gov/electric/how-rates-are-set>

[109] KCC. Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018. December 2018. P. 27.

Figure 31. Kansas IOUs' requested vs. authorized ROEs

Note: The following are the IOUs that requested those ROEs: 2010 – KCP&L; 2012 – KCP&L; 2015 – KCP&L; 2018 (W) – Westar; 2018 (K) – KCP&L

Source: Data provided by the KCC from LEI's data request.

Figure 32. ROEs in Kansas and surrounding states (Average of ROEs from 2010 – 2019)

Source: KCC data request response (for Kansas) and commercial third-party database for all other states (accessed on November 19, 2019)

4.2.2.3 Operating costs

The third component of the revenue requirement is **operating costs**. Operating costs are the expenses related to operating and maintaining the utility. These costs do not include capital outlays, and the utility does not earn returns on them. Operating costs include fuel costs, purchase

power expenses, other operations, and maintenance ("O&M") costs, depreciation, and taxes, as shown in Figure 33.

Figure 33. Components of operating costs

In Kansas, utilities are required to provide reports and/or documentation that demonstrate that their operations are run efficiently. As noted in KCC's 2018 retail rate study for Westar and KCP&L, "reasonable management is presumed on the part of the utility unless specific findings of inefficient management can be documented."[110]

4.2.3 Revenue requirements for transmission

SPP is responsible for assessing and evaluating the transmission revenue requirements for utilities in its RTO, including Kansas. As the utilities have transferred functional control over their transmission facilities to SPP, the RTO is responsible for the provision of transmission services to Kansas customers. Put another way, SPP acts as an agent for and of the transmission owners, i.e., the utilities in Kansas.[111]

The process of determining the revenue requirements starts with the utilities determining their annual transmission revenue requirement ("ATRR"), according to the Open Access Transmission Tariff ("OATT"). Utilities will determine their ATRR using a FERC-approved Transmission Formula Rate ("TFR") and submit them to SPP as well as to FERC as an informational filing. SPP will then post this ATRR information to its Revenue Requirements and Rates ("RRR") file that is made publicly available for all transmission owners in the SPP footprint and is used to establish

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[110] KCC. Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2019. Page 11. December 2018. <https://kcc.ks.gov/images/PDFs/electric/Rate-Study-Final-1-13-2018.pdf>

[111] KCC. *Report & Recommendation. In the Matter of Kansas City Power & Light Company Seeking Commission Approval to Implement Changes in their Transmission Delivery Charges Rate Schedules. Docket No. 19-KCPE-378-TAR.* July 10, 2019.

SPP's rates for transmission service. SPP's footprint is separated into multiple transmission pricing zones, and transmission service rates are based on a zonal ATRR that is based on the sum of the ATRR from each utility or transmission owner in a specific zone.[112] Once this ATRR is determined, the Kansas utilities' revenue requirement is based on its load ratio share ("LRS") within SPP.

SPP determines two types of service, Network and Point-to-Point, and charges for service over transmission owner facilities.[113] These revenues collected for the use of the transmission owners' facilities are provided back to transmission owners, with SPP collecting a fee defined in Schedule 1-A of the SPP tariff.[114]

Under the TFR, the ATRR for the applicable rate year is projected based on a historical year and then trued up to actual amounts after the applicable rate year. A summary of the process is illustrated in Figure 34 below.

Figure 34. Steps in determining the transmission revenue requirement

KCC is responsible for reviewing the TFR on behalf of retail customers. Once the revenue requirement supporting the Transmission Delivery Charge ("TDC") is filed, the KCC reviews the filing to ensure it is consistent with the SPP RRR filing. KCC staff will file a Report and Recommendation in the TDC docket the details of its findings, which typically occurs annually.

With respect to the new build transmission projects, SPP's Highway/Byway allocation methodology spreads the costs of the transmission line depending on the size and scope of the project. Highway projects are typically above 300 kV, and their costs are spread across the entire SPP footprint on a postage stamp basis, i.e., a single rate across all SPP members. Lower voltage projects (between 100 kV and 300 kV) are split between the SPP region and the local footprint at

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[112] Southwest Power Pool. *Attachment H: Annual Transmission Revenue Requirement for Network Integration Transmission Service.*

[113] Network service, or Network Integrated Transmission Service ("NITS") is defined as the service that allows the customer to "integrate, economically dispatch and regulate its current and planned resources to service its load in a manner comparable to that in which the Transmission Owners utilize the Transmission System to service their native load customers", while Point-to-Point service is defined as service "used for transfer of energy and/or grid capacity from designated points of receipt to designated points of delivery." (Source: SPP. Transmission Training Toolkit. October 2016)

[114] Southwest Power Pool. *Open Access Transmission Tariff.*

a ratio of one-third to two-thirds. Projects below 100 kV are borne by the local zone, known as Byway projects.[115]

Costs for region-wide transmission projects are recovered through FERC-approved TFRs, FERC-approved stated rates, or in some cases, state-approved TFR. In 2018, the total ATRR for Kansas represented approximately 17% of the total for the SPP region, which was $110 million, allocated to Kansas ratepayers.[116]

4.2.4 Rate design

Rate design refers to the itemized pricing structure reflected in consumers' monthly electric bills, including the underlying mechanism used to derive the rates.[117] Rate design starts with calculating the total annual revenue requirement of a utility, as discussed in Section 4.2.1, using the Cost-of-Service ("COS") mechanism. Following that step, the cost components are allocated to different customer classes after the KCC staff and other relevant parties conduct a Class COS ("CCOS") study. The CCOS study focuses on determining the relationship between the revenue recovered from each customer class and the cost caused by each customer class and aids in categorizing and allocating total utility costs to various rate classes.[118] This form of traditional rate design is the most commonly used form of rate design by state utilities in the US, given its simplicity and strong public acceptance.[119]

Rate design is the final step in the COS mechanism following the allocation of costs to different customer classes, including residential, commercial, industrial, and others. Figure 35 shows the series of steps involved in the COS mechanism, including rate design.[120]

Traditional rate designs consist of two parts, including a fixed charge, referred to as customer charge in Kansas ($ per month), and a per-unit energy charge applied to the amount of electricity consumed, referred to as energy or usage charge (cents/kWh). The customer charge accounts for costs incurred by the utility that are independent of electricity usage. On the other hand, the energy/usage charge accounts for the costs incurred to generate and distribute electricity to

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[115] FERC. *Order Accepting Tariff Revisions. (SPP Highway/Byway Methodology)* June 17, 2010.

[116] KCC. *Utilities and Common Carriers. Annual Report 2019.* 2019. P.14.

[117] Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[118] KCC. How rates are set. <https://kcc.ks.gov/electric/how-rates-are-set>

[119] Costello, Ken. "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives." National Regulatory Research Institute, Apr. 2014, <http://nebula.wsimg.com/5a9a01aeb5f95984861ea4b20d2c903b?AccessKeyId=8AF7098D30C5BF55909C&disposition=0&alloworigin=1.>

[120] Please refer to the deliverable for Task 1.6.4 on retail rates for an in-depth explanation of the first 4 steps of the cost service mechanism and how it is used by HECO and KIUC companies.

consumers. The energy/usage charge (in $/kWh) is calculated by dividing the total cost allocated to a given customer class by the total kilowatt-hour sales for that class.

Figure 35. Key steps in the COS study methodology

Figure 36. Types of charges on typical customer invoices

Customer charge ($ per customer)	Demand charge ($ per kW)
Used to recover costs related to billing and metering; outside of the generation and delivery of electricity. This applies to all customer classes regardless of usage levels. In certain cases, utilities use fixed charges to recover distribution system costs.	Used to recover the costs of generating and delivering electricity to large commercial and industrial consumers. Traditionally, these charges are based on the customer's peak demand (without considering coincidence with the system peak. This is rarely imposed on low-usage customer classes, namely, residential consumers.
Energy charge ($ per kWh)	**Facilities charge ($ per kW)**
Accounts for the cost of generating and delivering energy to a consumer (i.e., based on volumetric energy use). These charges are often flat but could also be designed in a variety of forms, including inclining or declining block rates, seasonal rates, or time-varying rates.	For customers who incur demand charges, the Evergy utilities (including Westar Energy and KCP&L) charge the facilities charge to recover costs associated with building, operating, and maintaining distribution systems closest to the specific customer. It is determined by using the customer's highest demand (in kW) within the past, rolling 12 months

Source: Evergy. "Billing definitions." Lazar, Jim, and Wilson Gonzalez. "Smart Rate Design for a Smart Future." RAP, July 2015.

Residential consumers in Kansas have a monthly customer charge and an energy charge. On the other hand, commercial and industrial consumers have a three-part rate, which also includes a demand charge (and a facilities charge, in the case of Westar Energy and KCP&L) in addition to

a customer charge and energy charge. Accordingly, the monthly rate reflected on monthly commercial bills typically consists of the charges described in Figure 36.

In addition to these charges, Kansas utilities charge various riders and adjustments to recover costs that are not covered through the charges discussed above. These charges are discussed in detail in Section 4.2.4.

4.2.5 Cost recovery mechanisms

In addition to recovering costs through base rate changes, utilities under the KCC's jurisdiction are allowed to recover specific cost categories through commission-authorized adjustment riders and legislatively mandated adjustment clauses. These costs are generally outside of the control of the utilities. Clear processes for calculating and recovering riders improve the ability of the utility to finance itself and reduces the regulatory burden on ratepayers. Figure 37 shows a list of these riders and charges.

These riders and charges do not undergo the same rate case process discussed in Section 4.2.1. Nevertheless, there is a process before utilities could charge these riders to the ratepayers. The utilities are required to file an application with the KCC requesting approval. Following initial filing, the KCC staff conducts an analysis of the application and issues a Report and Recommendation ("R&R"), which recommends a specific course of action to the KCC and is formally filed in the docket dedicated to the specific application. Throughout the process of conducting analysis, the KCC staff typically requests (via formal discovery requests and email correspondence) relevant documentation and meets with the utility at its corporate offices. Furthermore, relevant entities such as the CURB can file responses to the KCC staff's R&R. Finally, the KCC reviews the utility's application along with the Staff's R&R and, based on its review, orders a specific course of action (approval, approval with conditions, or disapproval).

Figure 37. Cost recovery mechanisms

Commission authorized adjustment riders	Legislative mandated adjustment clauses
• Energy Cost Adjustment ("ECA") • Environmental Cost Recovery Rider ("ECRR")	• Transmission Delivery Charges ("TDC") (as mandated in K.S.A 66-1237) • Ad Valorem Tax Riders (as mandated in K.S.A. 66-1179(f)) • Energy Efficiency Riders ("EER") as mandated in K.S.A 66-1283)

4.2.5.1 Energy Cost Adjustment ("ECA")

An ECA is a "formula-based rate" used by utilities to recover costs such as those related to fuel costs, purchased power costs, and transmission related expenses.[121] The utilities under the KCC's jurisdiction file ECA applications on an annual basis for each year-end. Moreover, at the end of each ECA year, the utilities file an Annual Cost Adjustment ("ACA") filing, which reflects the true-up costs from the estimated costs including in the ECA. In analyzing the requested ECAs, the KCC staff considers key areas including traditional fuel and purchase power review, the utility's involvements in the SPP IM, processes and control procedures, market performance and operational risk, audit of revenues and costs, and the benefits of SPP IM participation for Kansas ratepayers as summarized in Figure 38.[122]

Figure 38. Key areas considered in the evaluation of ECA applications

Traditional Fuel and Purchased Power review	Review monthly settlement computations, actual sales (KWh), actual fuel costs, actual purchased power costs, and actual emissions costs
SPP Integrated Marketplace ("IM")	Evaluate process and control procedures, management of market performance and operational risk, Kansas' actual share of IM revenue and costs, and benefits of participation in IM
Processes and Control Procedures	Review control procedures for verifying settlement statements and invoices from SPP, process for verifying meter data and Bilateral Settlement Schedules, and process for dispute monitoring
Market Performance and Operational Risk	Assess process for determining profitability of incremental market sales in SPP, strategy for bidding strategies for the IM, and hedging strategies for Auction Revenue Rights and Transmission Congestion Rights
ACA Audit of Revenues and Costs	Review KCC Monthly IM Activity Reports, weekly SPP settlement statements, general ledger and application for sample months
SPP IM Benefits to Kansas Ratepayers	Conduct analysis of short-run marginal costs associated with generation and transmission and assess benefits of SPP IM participation in terms of reducing overall costs to serve utility's load

From 2009 to 2019, the utilities had an average ECA Rider of approximately 1.79 cents/kWh (KCP&L), 2.04 cents/kWh (Westar Energy), and 2.95 cents/kWh (Empire District), with an overall average of 2.26 cents/kWh. Figure 39 below shows a summary of KCC approved ECAs for Westar Energy, KCP&L, and Empire District in the last ten years (2009-2019). On average, the

[121] KCC. *Rate study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018.

[122] Based on a comprehensive review of KCC orders on ECAs. Please note that these are requirements that were noted throughout the ECA orders reviewed and specific utility names have been omitted to reflect general requirements.

ECA represents approximately 3.5%, 11%, and 31% of the total bill for Westar Energy, KCP&L, and Empire District, respectively.

Figure 39. Approved ECA to date

Source: Data provided by the utility from LEI's data request

4.2.5.2 Environmental Cost Recovery Rider ("ECRR")

The ECRR tariff, approved in 2005 (Docket No. 05-WSEE-981-RTS), aimed to allow Westar Energy to recover costs associated with "mandatory environmental upgrades through a monthly surcharge rather than adding these costs to base rates after the projects are completed."[123] Following petitions for reconsideration and judicial review, KCC's provisions of the ECRR were upheld by the Kansas Court of Appeals, given that the KCC staff would "review the ECRR projects for prudence and necessity and a true-up mechanism would ensure recovery of costs expended."[124] The procedural guidelines for ECRR filings were modified in subsequent orders (07-WSEE-978-TAR and 09-WSEE-737-TAR), and accordingly, Westar was required to make annual ECRR filings. The ECRR was discontinued in 2015, following an order by the KCC.[125]

Westar Energy's approved ECRR fluctuated over the years and had an average value of 7.03 cents/kWh. Figure 40 below illustrates Westar Energy's approved ECRR from 2009 to 2015. During this period, on average, the ECRR represented approximately 14% of the total bill.

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[123] KCC Order Approving Revisions to Westar's Environmental Cost Recovery ("ECRR") Tariff. Docket No. 09-WSEE-737-TAR-CPL-1. May 21, 2015. <http://estar.kcc.ks.gov/estar/ViewFile.aspx/09-737%20Order%20Approving%20Revisions%20to%20Westar's%20Environmental%20Cost%20Recovery%20(ECRR)%20Tariff%20(2015).pdf?Id=c2d70eb2-abca-42c3-b5a8-4360ccd758f9>

[124] Ibid.

[125] KCC Order Approving Stipulation and Agreement. Docket No. 15-WSEE-115-RTS. September 24, 2015. <http://estar.kcc.ks.gov/estar/ViewFile.aspx/20150924104744.pdf?Id=29b7b55e-b40c-4f66-9335-153bfe44a81e>

Figure 40. Westar Energy approved ECRR (2009-2015)

Source: Data provided by the utility from LEI's data request

4.2.5.3 Transmission Delivery Charge ("TDC")

The TDC is used to recover transmission-related costs resulting from "any order of a regulatory authority having legal jurisdiction over transmission matters, including orders setting rates on a subject-to-refund basis."[126] Accordingly, utilities use TDCs to recover SPP costs associated with retail transmission services.

The TDC is allowed within the framework of K.S.A 66-1237 and enables utilities to recover transmission-related costs through a charge on customer bills. This is typically set using a TFR tariff, which features projected costs that are later trued-up with interest.[127]

The KCC notes that all the IOUs have applied for a TDC in the framework of K.S.A. 66-1237, which allows them to earn a FERC-authorized return for their transmission-related revenue requirements.[128] This ROE is typically higher than that authorized by the KCC, and the regulator notes that for Westar and KCP&L, the return is 10.3% and 11.1%, respectively.[129] As noted in Section 4.2.2.2, the average KCC authorized ROE for IOUs in Kansas in 2018 was 9.3%. The TDC

[126] K.S.A. 66-1237(c).

[127] KCC. *KCC Oversight of Electric Transmission in Kansas.* January 2016.

[128] KCC. *Neutral Testimony on Senate Bill 24. Submitted by Justin Grady, Chief of Accounting and Financial Analysis, Utilities Division on Behalf of The Staff of the Kansas Corporation Commission.* Before the Senate Utilities Committee. January 31, 2019.

[129] Ibid. LEI notes that this is likely to change given recent FERC ruling. This return also includes the 0.5% adder granted to all transmission owners in a FERC-approved RTO such as SPP.

is based on the ATRR for costs recovered under defined schedules of the OATT for service offered by SPP for service to the utility's retail customers, as discussed in Section 4.2.3.[130, 131]

Figure 41. KCC-approved TDC (derived by SPP using FERC formula) (2009-2015)

Source: Data provided by the utility from LEI's data request

Westar Energy had approved TDC each year, while KCP&L implemented them only in 2015, 2017, and 2018, and Empire District only in 2019. For the years in which TDCs were implemented, the average values were 0.68 cents/kWh (Westar Energy),[132] 0.87 cents/kWh (Empire District),[133] and 0.60 cents/kWh (KCP&L),[134] with an overall average of 0.72 cents/kWh for the three IOUs.

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[130] The schedules include: Schedule 1A (Tariff Administration Service); Schedule 9 (Network Integration Transmission Service); Schedule 10 (Wholesale Distribution Service); Schedule 11 (Base Plan Charge); Schedule 12 (FERC Assessment Charge); and Other costs associated with Schedule 1 feeds for transmission service.

[131] Westar Energy. *Refiling of Transmission Delivery Charge for Effects of Tax Cut and Jobs Act – 18-WSEE-355-TAR*. August 31, 2018.

[132] From 2009-2018 for customer type that Westar Energy charges in $/kWh. These include the following customer type: Auxiliary, Special Contract (a) and (b), DOR, RTP Ed Service, GSS, ICS, OPS, Pilot LED Street Lighting, PAL, RITODS, RS, Restricted Peak, RS – DG, REIS, RS to Schools, RTESC, ST, SGS, SGSCO, SES, SL, RESTOU, TS.

[133] For 2019 only for the following customer type: Residential – RG, Residential RGW, Residential – Total Electric Service RH, Commercial – CB, Small Heating – SH, Total Electric Building – TEB, Lighting Service – SPL, Lighting Service – PL, and Lighting Service – LS. The average TDC does not include General Power and Transmission Service -PT because billing is in KW.

[134] For years 2015, 2017, and 2018 for the following customer type: Small General Service, Residential Service, and Lighting Service. The average excludes the following customer type where billing is in KW (not KWh): Medium General Services and Large General Services.

It is also important to note that between 2009 and 2018, Westar Energy's TDC increased by approximately 15%, from 0.24 cents/kWh to 1.00 cents/kWh. This increase can be attributed to higher SPP transmission cost allocation to Westar Energy.[135] In the same period, on average, the TDC represented approximately 4.2% of the total bill for Westar Energy. Figure 41 illustrates KCC-approved (derived by SPP using FERC formula) TDCs by the KCC between 2009 and 2018. In the three years that KCP&L had TDCs, on average, the TDC represented approximately 4.3% of the total bill, as illustrated in Figure 44 and Figure 45, respectively, in Section 4.2.5.6.

4.2.5.4 Ad Valorem Tax Rider

Ad Valorem Tax Riders are used to recover costs incurred due to annual changes (increase or decrease) in ad valorem property taxes as charged in the "books and records of the utility."[136] Prior to the approval of the Ad Valorem Tax Rider, the KCC staff conducts a review of the given utility's tax statements and determine whether or not it agrees with the Ad Valorem tax expense claimed by the utility. Moreover, the KCC staff reviews the utility's documentation supporting the calculation of the Ad Valorem Tax Rider and the revenues collected during the year for which an application was filed. Following its determination of whether the given utility's Ad Valorem Tax rider is accurately calculated, the KCC staff recommends a specific course of action (approval, or approval with certain conditions, or disapproval).

Figure 42. Approved Ad Valorem Tax Riders (2009-present)

Source: Data provided by the utility from LEI's data request

[135] Tariff for Westar Energy. Docket No. 19-WSEE-327-TAR. <http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20190215164140.pdf?Id=a2cc7158-4f59-48c3-a307-31ff4861fba5>

[136] K.S.A. 66-117 (f).

From 2009 to 2019, Westar Energy has charged ratepayers the approved Ad Valorem Tax Riders ("AVTRs") each year while KCP&L implemented them only between 2012 and 2018 and Empire District between 2015 and 2019. For the years in which AVTRs were charged, the average values were 0.075 cents/kWh (KCP&L), 0.076 cents/kWh (Westar Energy), and 0.184 cents/kWh (Empire District), with an overall average of 0.111 cents/kWh. Figure 42 shows a summary of approved Ad Valorem Tax Riders ("AVTRs") in Kansas between 2009 and 2019 (with negative values representing refunds to customers). In general, AVTRs represent less than 1% of the total bill.

4.2.5.5 Energy Efficiency Rider

The Energy Efficiency Rider ("EER") is used to recover costs associated with utility energy efficiency programs. Before the approval of a utility's EER application by the KCC, the KCC staff investigates the accounting and rate design implication of the given utility's request. In regard to accounting, the KCC staff reviews the utility's general ledger/journal entry that supports the proposed program costs to confirm that they were incurred and properly recorded by the utility for the given year. In evaluating the rate design implications of the proposed EER, the KCC staff reviews the utility rate calculations, including the specific data used to determine the ERR rates (such as the EER factor, and consumption data, among others). Following these evaluations, the KCC staff recommends a specific course of action to the KCC, after which the KCC reviews the utility's application and the Staff's R&R and passes an order which either approves or disapproves the application.[137]

Figure 43. Approved EERs (2009-present)

Source: Data provided by the utility from LEI's data request

[137] Based on a comprehensive review of EER orders published in KCC's order search online site. For example, refer to the final orders for Docket No. 19-KCPE-398-TAR, Docket No. 18-KCPE-420-TAR, and Docket No. 17-WSEE-014-TAR, among others.

Westar Energy implemented approved EERs each year (except 2010), while KCP&L applied them only between 2009 and 2015 and Empire District between 2011 and 2013. For the years in which EERs were implemented, the average EER values were 0.015 cents/kWh (Empire District), 0.034 cents/kWh (Westar Energy), and 0.078 cents/kWh (KCP&L), with an overall average of 0.042 cents/kWh. Figure 43 shows a summary of approved EERs in Kansas between 2009 and 2019. In general, the EER represents less than 1% of the total bill.

4.2.5.6 Contribution of surcharges and riders to rising wholesale and retail electricity rates

The contribution of the combined riders and surcharges to the total bill is sizeable. As shown in Figure 44 and Figure 45, these combined riders and surcharges contributed an average of 42.6% and 17.4% relative to the total bill for Westar Energy and KCP&L for the past ten years, respectively. These percentage values have been relatively stable for most of the riders for the past several years except for the TDC, which has been increasing in the past few years. Among these riders and surcharges, the ECRR has the highest share at 35.9% on average for Westar Energy. On the other hand, the ECA provided an average of 15.2% per year for KCP&L.

Between 2009 and 2018, Westar Energy's total riders and surcharges have increased by an average of 15% per year, while the total overall rates experienced an average annual increase of just 5%. The major drivers of the rise in total riders and charges are the ECRR from 2009 to 2015 and the increasing share of ECA and TDC in the years since. The base rates still comprise the largest share in Westar Energy's overall rates at an average of 57% per year from 2009 to 2018. It is also worth noting that in the past three years, the base rates' share of the overall rates increased to 76% because there were no ECRR post-2015. Figure 44 below illustrates the trends in Westar Energy's cost recovery mechanisms, along with changes in its base rate.

Figure 44. Westar Energy cost recovery riders & adjustments vs. rates (2009-present)

Source: Data provided by the utility from LEI's data request

Similarly, between 2009 and 2018, KCP&L's total riders and surcharges grew by an average of 13% per year, while its overall rates increased by an annual average of approximately 6% per year. The major driver of the increase in KCP&L's total riders and charges is the ECA, which grew

from 1.2 cents/kWh in 2009 to 2.2 cents/kWh in 2018 and accounted for 15.2% of the total riders and surcharges. The base rates still make up the largest share of the total overall rates at an average of 83% per year. Figure 45 below illustrates the trends in KCP&L's cost recovery mechanisms, along with changes in its base rate.

Figure 45. KCP&L trends on cost recovery mechanisms and overall rates (2009-present)

Source: Data provided by the utility from LEI's data request

Likewise, between 2010 and 2019, Empire District's total riders and surcharges increased by an average of 3.2% per year, while its overall rates grew by an annual average of 1.9% per annum, as shown in Figure 46. The largest rider for Empire District is ECA, which comprised on average 95% of the total riders and surcharges per year from 2010 to 2019.

Figure 46. Empire District trends on cost recovery mechanisms and overall rates (2009-present)

Source: Data provided by the utility from LEI's data request

4.2.6 Contribution of investments made in renewable generation resources and electric transmission resources to the obsolescence of other generation facilities

For the purpose of this Study, LEI equated obsolescence of generation facilities with plant retirements, although reduced capacity factors of existing plants may be another indicator. Since 2009, more than 1,500 MW of capacity have been retired in the State (Figure 47), the majority of which (79%) were natural gas plants, followed by coal plants (19%), and oil plants (2%). Most of the retirements in Kansas took place in 2015 and 2018 due to a combination of reasons including age, environmental regulation, and poor economic performance. The MW-weighted average age of these retired thermal plants has been 54.5 years.

Figure 47. Cumulative retirements in Kansas (2009 – 2018)

Source: Commercial third-party database (Accessed on November 11, 2019).

Similarly, more than 6,000 MW of plants have retired in SPP from 2009 to 2018 (Figure 48). More than 80% of these retirements were gas and coal-fired plants. The majority of these retirements happened in 2016, including more than 1,200 MW from coal plants and 577 MW from a nuclear plant.[138] The 2018 SPP State of the Market Report stated, "a recent wave of generator retirements, particularly of coal-fired generation, has been widely observed throughout the country. The SPP market should be expected to follow this trend because of excess capacity, aging fleet, and cost disadvantage of certain types of generation technologies vis-à-vis the prevailing market prices."[139]

[138] For instance, Empire District retired four generators between 2009 and present: Riverton Units 7 (2014), 8 and 9 (2015) and Asbury Unit 2 (2014). According to Empire District "none of these generators were retired solely due to age. The Riverton units were retired because it was not economical to retrofit the plants to meet the Mercury Air Toxics Standards. Asbury Unit 2 was retired because it could no longer provide economical service as a result of the air quality control system upgrade to the Asbury Unit 1 steam turbine."

[139] SPP. "2018 State of the Market Report." May 15, 2019. P. 233.

Figure 48. Cumulative retirements in SPP (2009 – 2018)

Source: Commercial third-party database (Accessed on November 11, 2019).

In general, generation plants retire due to economics or old age. Plants that are uneconomic are unable to cover their minimum going forward fixed costs due to low energy prices. For instance, according to the most recent SPP State of the Market Report, energy prices from 2015 to 2017 did not support the ongoing maintenance costs of scrubbed coal units. Additionally, SPP's net revenues analysis indicates that revenues have been insufficient to support the cost of new generation entry for scrubbed coal, advanced gas/oil combined cycle, and advanced combustion turbine, since the inception of the IM.[140]

Energy prices in the Westar zone - as well as in SPP - broadly have been decreasing in the past few years, except for 2018 when there was a slight increase in energy prices. As shown in Figure 49, annual average day-ahead energy prices for the Westar zone in SPP have decreased by 7% per year from $33.6/MWh in 2014 to $24.7/MWh in 2018.

Figure 49. Annual average day-ahead energy price for Westar price zone (2014 – 2018)

Source: Commercial third-party database (Accessed on November 11, 2019).

[140] SPP. "2018 State of the Market Report." May 15, 2019. P. 151.

The same is true for some of the SPP zones as shown in Figure 50. Low energy prices can be attributed to a confluence of factors including low gas prices, negative energy prices in SPP and more zero marginal cost resources due to influx of renewable resources, and improved transmission system. These drivers are discussed below.

Figure 50. Annual average day-ahead energy price for major price zones in SPP (2014 – 2018)

Note: AEPM: American Electric Power; EDE – Empire District Electric; GRDA – Grand River Dam Authority; INDN – City of Independence; KACY – Kansas City BPU; KCPL – Kansas City Power and Light; LES – Lincoln Electric System; MPS – Missouri Public Service; NPPD – Nebraska Public Power District; OKGE – Oklahoma Gas & Electric; OPPD – Omaha Public District; SECI – Sunflower Electric; SPRM – City Utilities of Springfield, Missouri; SPS – Southwestern Public Service Co; WFEC – Western Farmers Electric Cooperative; and WR - Westar

Source: Commercial third-party database (Accessed on November 11, 2019).

With respect to old age, data based on capacity-weighted age shows that plants in Kansas did not retire at an earlier age relative to the average retirement age in SPP. In fact, coal, gas (GT), and oil plants in Kansas retired at a later age on average than the other plants in SPP (Figure 51).

This implies that some thermal units in Kansas may have indeed been retired due to their age rather than premature retirements driven by other factors.

Figure 51. MW-weighted average age of plant retirements in Kansas and SPP

Fuel Type	Kansas	SPP
Coal	55.5	45.7
Gas - ST	50.3	51.3
Gas - GT	40.5	34.3
Gas - IC	38.9	39.1
Oil	38.8	35.7

Source: Commercial third-party database (Accessed on November 11, 2019).

In SPP, the prevalence of negative pricing events continues to be a factor in both the day-ahead and real-time markets. Specifically, the incidence of negative price intervals in the real-time market was just over 3% in 2018, down from over 7% in 2017.[141] The frequency of negative prices is a leading indicator of both surplus capacity primarily caused by the increased entry of renewables in the system and a contributing factor to the declining profitability of coal units.

In addition, natural gas prices have traditionally driven wholesale prices in SPP, and as gas prices have remained low, so have energy price trends.[142] Natural gas comprises 28% of the 2017 total installed capacity in Kansas, making declining natural gas prices in the region another driver of falling energy prices. Between 2014 and 2018, gas prices at the Panhandle Eastern Pipeline, the benchmark gas hub for SPP, have declined by 13% (Figure 52).

[141] SPP. "2018 State of the Market Report." May 15, 2019. P. 123.

[142] Ibid. P. 107

Figure 52. Panhandle gas prices (2014-2018)

Source: Commercial third-party database (Accessed on November 11, 2019).

Moreover, Kansas has experienced a significant influx of renewable generation resources in the last few years. Renewable capacity in the State grew by 21% per year on a CAGR basis from 2009 to 2018 (Figure 53), with wind accounting for 99% of renewable capacity. A total of approximately 4,774 MW of wind capacity was added since 2009.

Likewise, renewable capacity in SPP grew by 12% in the past ten years. The vast majority, or 97%, of these renewables, came from wind. The growth in wind capacity started in 2014 with a 55% jump from the year before (2013) and the highest increase in 2015 with a 74% growth in wind capacity. Figure 53 and Figure 54 show the cumulative new entry of renewables in Kansas and SPP, respectively.

Wind integration brought low-cost generation to the SPP region. According to the 2018 SPP Market Report, the high amount of available generation capacity has contributed to the relatively low prices in the SPP market, and "this affects the financial viability of generators as low prices that are not supportive of the existing generation capacity makes future retirements more likely."[143]

[143] SPP. "2018 State of the Market Report." May 15, 2019. P. 192.

Figure 53. Cumulative new entry of renewables in Kansas (2009 – 2018)

Note: Renewable resources include biomass, hydro, solar, and wind. 2009 number consists of all operating renewables for the year, not just incremental.

Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 54. Cumulative new entry of renewables in SPP (2009 – 2018)

Note: Renewable resources include biomass, hydro, solar, and wind. 2009 number includes all operating renewables for the year, not just incremental.

Source: Commercial third-party database (Accessed on November 11, 2019)

Based on LEI's analysis, the growing penetration of wind energy has had a positive (but not strong) correlation with the retirement of more expensive and less efficient thermal power plants. Figure 55 illustrates the incremental new entry of renewables as compared to the retirement of thermal power plants for each year.

However, it cannot be generalized that the retirements of these plants are due to the influx of wind. Other factors also contributed to plant retirement, as mentioned earlier.

Figure 55. Incremental new entry of renewables versus retirements in Kansas (2000 – 2018)

Source: Commercial third-party database (Accessed on November 11, 2019)

Another factor that contributed partially to the decrease in energy prices in SPP was the increased transmission that alleviated congestion bottlenecks and higher loads.[144] For the past ten years, the growth in transmission investment in terms of the number of miles averages 2% per year (Figure 56). These include transmission lines of Evergy Inc., ITC Holding Corp, and Midwest Energy Inc. with 115 kV and above.

Based on LEI's analysis, there appears to be no direct relationship between the increase in transmission investments in miles and plant retirements in the State, as shown in Figure 57.

Figure 56. Cumulative transmission lines in miles (2009-2018)

Note: The transmission investments above in miles are for 115 kV lines and higher as those are the lines that are considered as transmission lines in the State. Anything lower than 100 kV is considered as distribution lines.

Source: Commercial third-party database (Accessed on November 11, 2019)

[144] SPP. "2018 State of the Market Report." May 15, 2019. Page 48.

Figure 57. Transmission investments versus retirements in Kansas

Source: Commercial third-party database (Accessed on November 11, 2019)

4.2.7 IOU electricity rates

IOU electricity rates in Kansas vary across the different IOUs and customer classes. As illustrated in Figure 58 below, retail rates for the residential customers of Westar Energy and KCP&L are, in general, higher than those of commercial and industrial customers. Between 2009 and 2019, retail rates for Westar and KCP&L residential customers increased by 45.8% and 48.9%, respectively. On the other hand, retail rates for Empire District's residential customers declined by approximately 8.6%.

Figure 58. Retail rates for IOUs by customer class (2009-2018)

Note: The residential rates for Empire District represent those for "Total Electric Service RH" groups. The industrial rates of Empire District represent the average of all per kWh rates across the different industrial customer classes.

Source: Data provided by the utilities from LEI's data request

Similarly, retail rates for Westar and KCP&L's commercial and industrial customers increased, while those for Empire District's commercial and industrial customers declined. As illustrated in the figure, between 2009 and 2019, retail rates for Westar and KCP&L's commercial customers increased by 36.3% and 48.0%, respectively, while the retail rates for Empire District's commercial customers remained relatively constant. Retail rates for Westar and KCP&L's industrial customers also increased by 28.8% and 49.9%, respectively, while the retail rates for Empire District's industrial customers remained relatively constant.

4.2.8 Evaluation of the effectiveness of the ratemaking practices

LEI assessed the effectiveness of the ratemaking practices for IOUs in the next subsections by using the guiding principles discussed in Section 4.1 (and summarized in Figure 59 below) and the items mentioned in Sub. for SB 69.

Figure 59. Guiding principles in the ratemaking process

Principle	Description
1) Economic efficiency and performance	Provide funding to maintain reliability consistent with customer expectations while recognizing such preferences are increasingly varied.
2) Customer focus and bill impacts	Encourages the pursuit of opportunities for better cost containment
3) Stability of the sector	Investment signals must be proportional to associated risk, and market returns and remuneration should take into account the impact on debt service coverage ratios and associated parameters for maintaining an efficient capital structure. Also, stranded costs should be identified, quantified, and recovered in a fair manner
4) Cost causation and avoidance of cross-subsidies	One of the most fundamental principles of utility rate design is that the customer that causes a cost to be incurred should pay that cost. If cost causation could be perfectly identified, cross-subsidies (either between or within customer classes) could be avoided.
5) Evolving utility structure to facilitate innovation	Framework must balance incumbent opportunities against market participation, reducing barriers to the third-party providers of services. This also includes the elimination of capex, ownership, and technology biases and emphasizes the focus on a long-run least-cost approach that values optionality for determining solutions to identified system and customer needs
6) Regulatory simplicity	Ratemaking must balance appropriate oversight with administrative simplicity to avoid an overly burdensome process for all parties. Moreover, the framework must have built-in decision criteria and evaluation to increase accountability and advance strong stakeholder support

In conducting the analysis for the various issues highlighted in Sub. for SB 69, LEI applied the summarized principles by first determining which of the principles are directly applicable to the given analysis area. For instance, in evaluating the ability of IOUs to attract adequate utility capital investment, LEI selected the principles of economic efficiency and performance along with the stability of the sector. LEI followed a similar methodology in its analysis of all the issues areas for Kansas IOUs, as is summarized in the following sections.

4.2.8.1 Ability of IOUs to attract needed utility capital investment

The ability of IOUs to attract needed utility capital investments falls under the two guiding principles discussed in Section 4.1, namely, economic efficiency and performance and stability of the sector. For economic efficiency and performance, the ratemaking practices should be able to provide funding to maintain reliability consistent with customer expectations. For the stability of the sector, investment signals must be proportional to the associated risk.

> "[A] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties....The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."
>
> Source: Bluefield Water Works & Improvement Company v. Public Service Comm'n, 262 US 679, 692 (1923)

Based on LEI's analysis, the current ratemaking practices in the State have enabled the IOUs in Kansas (specifically, Westar Energy and KCP&L, which are part of the publicly traded Evergy Inc.) to attract needed capital investments, as evidenced by the utilities' liquid securities, which trade consistent with peers' Price-to-Earnings Ratio ("P/E") ratio, and their ability to raise debt and equity. These are discussed below.

Evergy Inc.[145] is a publicly listed company with the New York Stock Exchange ("NYSE"). The stock market provides one way to raise capital to a company that it can use to expand or fund its business. Shares of a firm represent equity ownership in that firm. A stock's volume means the total amount of security that changes hand over a given period of time.

Stock prices represent the market's perspective of the company's worth. If the company does well or if the investors have strong confidence in the company, the stock price generally can be expected to increase. Evergy's stock price has been on upward trends rising by 15% since the merger between Great Plains Energy and Westar Energy. Figure 60 below illustrates the stock prices for Great Plains Energy and Westar Energy prior to the merger (from January 2014 to June 2018) and Evergy's stock prices from June 2018 (the date of the merger) until the present. Looking at the company's historical trading data indicates that Evergy's shares have been able to attract investors.

Furthermore, Westar Energy's stock price grew at a higher rate than the Dow Jones Utilities Index before the merger from 2014 to 2018, as shown in Figure 61. The Dow Jones Utilities Index consists of 15 stocks or companies, each having a weight that is used along with the stock's price

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[145] According to Evergy Inc's 2019 Proxy document, the entities that has more than 5% of common shares outstanding of Evergy Inc. include Vanguard Group (11.3%), BlackRock Inc. (7.5%), and T. Rowe Price Associates, Inc. (5%) based on approximately 252,138,583 shares of our common stock outstanding as of March 1, 2019.

to calculate the Index.[146] Evergy Inc.'s stock prices' growth aligned with the Dow Jones Utilities Index post-merger until early 2019 (
Figure 62). Nevertheless, the Dow Jones Utilities Index's grew higher than Evergy Inc.'s stock prices starting the second quarter of 2019.

Figure 60. Evergy, Inc. stock prices (2014-2019)

Note: Only days for which values are available are shown in the figure.
Source: Commercial third-party database (Accessed on November 19, 2019)

Figure 61. Dow Jones Utilities Index, Great Plains Energy, and Westar Energy (2014-Pre-merger 2018)

Note: Only days for which values are available are shown in the figure.
Source: Commercial third-party database (Accessed on December 27, 2019)

[146] These companies include AES Corporation, American Electric Power Company, Inc., American Water Works Company, Inc., CenterPoint Energy, Inc., Consolidated Edison, Inc., Dominion Energy, Inc., Duke Energy Corporation, Edison International, Exelon Corporation, FirstEnergy Corp., NextEra Energy, Inc., NiSource Inc., PG&E Corporation, Public Service Enterprise Group Incorporated, Southern Company.

Figure 62. Dow Jones Utilities Index and Evergy Inc. (Post-merger 2018-2019)

Note: Only days for which values are available are shown in the figure.

Source: Commercial third-party database (Accessed on December 27, 2019)

P/E ratio is the ratio of the company's stock price in relation to its earnings per share. Compared to other parent companies that operate in the region such as Ameren, Black Hills, MDU Resources, and Xcel Energy, Evergy's P/E ratio has been aligned to these companies since its merger, and in fact, had the highest P/E ratio. Figure 63 shows a comparison of the average P/E ratio since June 2018 until December 2019. This shows that Evergy is valued at a similar level to its peers on a P/E basis.

Figure 63. Average P/E ratio of selected parent companies operating in the region (June 5, 2018 – December 23, 2019

Source: Commercial third-party database (Accessed on December 24, 2019)

Furthermore, Evergy has issued both debt and equity in recent years. As summarized in Figure 64 below, Evergy has issued approximately $2.5 billion in non-convertible debt since August 2018. In addition, Evergy has issued $270 million in common equity since August 2016.

Figure 64. Evergy, Inc. debt and equity transactions

Announcement Date	Transaction Value ($MM)	Transaction Type
9/5/2019	$800	Non-convertible Debt
9/5/2019	$800	Non-convertible Debt
8/12/2019	$300	Non-convertible Debt
3/18/2019	$400	Non-convertible Debt
2/22/2019	$22	Non-convertible Debt
12/31/2018	$15	Non-convertible Debt
12/31/2018	$10	Non-convertible Debt
12/31/2018	$31	Non-convertible Debt
12/31/2018	$45	Non-convertible Debt
12/31/2018	$73	Non-convertible Debt
12/31/2018	$73	Non-convertible Debt
8/8/2018	$23	Non-convertible Debt
Total	**$2,592**	

Announcement Date	Transaction Value ($MM)	Transaction Type
9/6/2018	$59	Common Equity
6/15/2018	$154	Common Equity
3/18/2016	$57	Common Equity
Total	**$270**	

Source: Commercial third-party database (Accessed on November 19, 2019)

Analysis of stock performance, institutional investment trends, valuation metrics, and recent securities issuances suggests Kansas' large IOUs can attract adequate capital to finance needed investments.

4.2.8.2 Balances utility profits with public interest objectives of achieving competitive rates over time

Another key area to evaluate the effectiveness of the ratemaking practices for the IOUs is to determine if it balances utility profits with the public interest objectives of achieving competitive rates over time while providing the best practicable combination of price, quality, and service. This falls under the economic efficiency and performance principle, which emphasizes the importance of maintaining reliability standards consistent with customer expectations.

As discussed in Section 3.3, electricity rates in Kansas, specifically their relative competitiveness in relation to the rates of regional states, has been an area of contention for stakeholders in the state. Retail electric rates of IOUs in Kansas (mainly Westar Energy and KCP&L) have been increasing over the past decade. As illustrated in Figure 65 below, residential, retail electricity rates for Westar Energy and KCP&L increased by 45.8% and 48.9%, respectively, between 2009 and 2018. On the other hand, residential electric rates for Empire District have been relatively stable over the past decade, declining slightly by 8.6% between 2009 and 2018, as also shown in the figure below.

Figure 65. Residential electric rates (cents/kWh) for the three IOUs in Kansas (2009 – 2018)

Note: The rates above are the base rate values, excluding any surcharges or riders.

Source: Data provided by the utilities from LEI's data request

The increasing trend of IOU retail electricity rates in the State indicates a degree of imbalance between utility profits and public interest objectives when considering rates in other regional states. The rates of Westar Energy and KCP&L are significantly above average when compared to the average residential, retail electric rates of similar vertically integrated utilities in regional states (Figure 66). They are specifically, 20% and 22% higher than the regional average, respectively.

Figure 66. Residential electric rates (cents/kWh) in Kansas and surrounding states

Note: The rates above are the base rate values, excluding any surcharges or riders.

Source: Rate Study by Westar Energy and KCP&L

To measure public interest, LEI examined whether IOUs provide reliable services.[147] Based on LEI's review, Kansas' IOUs are performing well in this regard as evidenced by the feedback received from stakeholders[148] as well as the IOUs' reliability standards, namely the SAIDI, SAIFI, and CAIDI:

- **System Average Interruption Duration Index ("SAIDI")** measures the total number of minutes, on average, that a customer is without electricity per year (excluding momentary interruptions). SAIDI is estimated as the sum of the restoration time for each interruption event times the number of interrupted customers for each interruption divided by the total number of customers;
- **System Average Interruption Frequency Index ("SAIFI")** measures the average number of times a customer's supply is interrupted in a year, excluding momentary interruptions. SAIFI is estimated as the total number of customer interruptions divided by the total number of customers served; and

Customer Average Interruption Duration Index ("CAIDI") measures the average duration in minutes of each interruption a customer faces. It is calculated by dividing SAIDI by SAIFI, or the sum of customer interruption durations divided by the total number of customer interruptions. The reliability indicators of KCP&L and Westar Energy have been improving for the past few years. As shown in Figure 67, the total number of minutes that a customer is without electricity (SAIDI) or the duration and frequency of interruption (SAIFI and CAIDI) have been declining for the past 2-3 years.[149]

Figure 67. KCP&L and Westar Energy Inc.'s SAIDI and SAIFI (2014-2018)

Source: Provided by Evergy in response to LEI's data request.

[147] LEI used reliability metrics because these are the ones available publicly and provided by the utilities. There were no customer service or service quality metrics available publicly.

[148] Based on the meeting with the representative of the consumer groups on October 1, 2019 at Topeka, Kansas. Stakeholders agreed that reliability "was not an issue in Kansas."

[149] Since there are no mandatory targets for SAIDI, SAIFI, and CAIDI in the state, the best way to measure these is to see historical trends and see if there are improvements in the reliability performance.

Figure 68. KCP&L and Westar Energy Inc.'s CAIFI (2014-2018)

Source: Provided by Evergy in response to LEI's data request.

Compared to other IOUs in the region, KCP&L and Westar Energy Inc. performed better than other IOUs in terms of SAIDI and SAIFI, while Empire District Electric and KCP&L achieved better CAIDI than the others (Figure 69 and Figure 70). Three out of the four IOUs in Kansas have a below regional average CAIDI (Figure 71), meaning their customers experienced shorter outages than the regional average.

Figure 69. Comparison of three-year average SAIDI among selected IOUs in the region (2016-2018)

Note: IEEE Standard SAIDI without Major Event Days.

Source: EIA Annual Electric Power Industry Report, Form EIA 861

Figure 70. Comparison of three-year average SAIFI among selected IOUs in the region (2016-2018)

Note: IEEE Standard SAIFI without Major Event Days.

Source: EIA Annual Electric Power Industry Report, Form EIA 861

Figure 71. Comparison of CAIDI among selected IOUs in the region (2018)

Note: Form EIA 861 does not have 2016 and 2017 CAIDI data; IEEE Standard CAIDI without Major Event Days.

Source: EIA Annual Electric Power Industry Report, Form EIA 861

4.2.8.3 Recovery from Kansas retail electric ratepayers of the full or partial cost of any investments no longer fully used or required to be used in service to the public within Kansas

The issue of recovering the full or partial cost of investments no longer in use or required to be used falls under the guiding principle of customer focus and bill impacts. Under this principle, effective ratemaking practices ought to encourage the pursuit of opportunities for better cost containment, which in this case, means that ratepayers should not pay for investments that are no longer fully used or required to be used in providing adequate services.

The KCC relies on the primary objective standards noted in K.S.A. 66-128 et seq. and K.S.A. 66-1239 to determine whether a proposed investment by a utility is justified or not.[150] In accordance with what is commonly referred to as the "used and useful principle," which requires that utility investments should be used by and useful to ratepayers before they are paid for, the KCC utilizes traditional means to evaluate new investments.[151] These means include "(1) pre-construction to determine the construction bid process (lowest reasonable cost) and the analysis for need (used and required to be used), (2) during construction to monitor costs, change orders, and record-keeping, and (3) post-construction to determine how well the project was managed, whether there were cost overruns that were justified or unjustified, and determination of whether any prudence issues exist."[152] The vetting process can be conducted through either a predetermination proceeding, through a regulatory plan filling, or review through a specific docket or rate case.[153,154]

Nevertheless, it appears ratepayers in Kansas are paying for investments that are less utilized, as evidenced by declining capacity factors of some coal and natural gas plants in the State. The overall average capacity factors of coal and natural gas plants in Kansas are also below the regional average. This may, however, be appropriate if less costly power is available from other sources.

The utilization rate (that is, capacity factor) of coal plants in Kansas has been declining over the last several years. As demonstrated in Figure 72, the capacity factor of coal plants in Kansas has declined by an average of 29%, with the highest decline being 42% (Tecumseh Energy Center between 2007 and 2018) and the lowest drop being 8% (Lawrence Energy Center between 2007

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[150] Information provided by the KCC in response to LEI's data request.

[151] Hoecker, James. "Used and useful: autopsy of a ratemaking policy" 1987 <https://www.eba-net.org/assets/1/6/25_8EnergyLJ303(1987).pdf>

[152] Ibid.

[153] Ibid.

[154] It should be noted that the KCC process does not consider whether alternative structures would work better.

and 2018). While these plants are still utilized, their declining capacity factor indicates that their competitiveness in relation to other generation sources is declining.

Figure 72. Historical capacity factors for coal plants in Kansas (2007 – 2018)

Note: The Riverton coal plant was converted to gas in 2012 and was retired in 2015.
Source: Commercial third-party database (Accessed on November 11, 2019)

Furthermore, coal plants in Kansas have below-average capacity factors compared to neighboring states. In 2018, the average capacity factor for coal plants in Kansas and neighboring states was approximately 54.5%, while the average capacity factor for coal plants in Kansas was just 50%, as illustrated in Figure 73.

Figure 73. Average capacity factors for coal plants in Kansas and surrounding states (2018)

Source: Commercial third-party database (Accessed on November 11, 2019)

When considering the specific vintage of coal plants (or when they went online) located in Kansas as compared to coal plants in neighboring states, the capacity factors of half of the coal plants in the State fall below average while the other half are above. (Figure 74). Compared to other coal plants in neighboring states with similar dates of initial construction, Tecumseh Energy Center and Lawrence Energy Center have capacity factors 10% and 14% above average, respectively. On the other hand, Jeffrey Energy Center and La Cygne have capacity factors 4% and 9% below average, respectively, which indicates that these plants are relatively underutilized.

Figure 74. Capacity factor of coal plants in Kansas and surrounding states by online year

Source: Commercial third-party database (Accessed on November 11, 2019)

Similar to coal plants, some of the natural gas plants (specifically, gas turbines ("GT")) in Kansas, also have below-average capacity factors compared to those in neighboring states. The capacity factor of natural gas plants in Kansas was 4% in 2018, which was 1% lower than the average (Figure 75). While operating at a capacity factor slightly below the regional average, the capacity factor of natural gas plants in Kansas is the 3rd highest in the region. This is because the capacity factors of gas turbines in Oklahoma and Texas pull up the regional average capacity factor.

Figure 75. Average capacity factors for natural gas (GT) plants in Kansas and surrounding states (2018)

Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 76. Capacity factor of natural gas (GT) plants in Kansas and surrounding states by year of construction

Source: Commercial third-party database (Accessed on November 11, 2019)

When considering the specific age of GT natural gas plants in Kansas in relation to those in neighboring states, two of the plants in Kansas have above-average capacity factors while one of them has a below-average capacity factor. As shown in Figure 76, Emporia Power Plant and

Gordon Evans Energy Center have capacity factors that are 2.1% and 0.2% higher than average, respectively. On the other hand, Osawatomie has a capacity factor that is approximately 73% lower than average, meaning that it is underutilized compared to the other GT plants in surrounding states in 2018.

4.3 Electric cooperatives

Co-ops are a form of ownership in which a company is effectively owned by its members, who are their customers. They are incorporated under the laws of the state in which they operate. Electric co-ops can either be (i) generation and transmission ("G&T") co-ops, (ii) distribution co-ops, or (iii) both. G&T co-ops provide wholesale power to distribution co-ops through their own generation or by purchasing power on behalf of the distribution members while distribution co-ops deliver electricity to the customers. Co-ops in the US operate according to the same set of core principles adopted by the International Co-operative Alliance. These principles are shown in Figure 77.

Figure 77. Co-op principles

Source: National Rural Electric Cooperative Association

Co-ops are democratically controlled by their members and governed by a board of trustees ("board"). Therefore, they are autonomous and independent. Generally, co-op members have equal voting rights (one member, one vote basis).

Some of the responsibilities of the board include setting major policies and procedures that are implemented by the co-op's management; advocating for the members; approving annual operating budgets, capital expenditure budgets, and compensation plans; recruitment and selection of CEO; and choosing an independent auditor for the annual financial audit.

As mentioned earlier, there are three G&T co-ops in the State that sell power to distribution co-ops. These three co-ops are the Sunflower Electric Power Corporation ("Sunflower"), Mid-Kansas Electric Company ("Mid-Kansas"), and Midwest Energy Inc. ("Midwest"). Sunflower Electric Power Corporation is owned and governed by six-member distribution co-ops who now serve more than approximately 200,000 people in central and western Kansas.[155] Mid-Kansas Electric Company, Inc. provides power to five distribution co-ops and one corporation that is serving customers in western and central Kansas counties.

The Sub. for SB 69 specified that the ratemaking processes for the electric co-ops should be assessed based on whether they are in the public interest, which as previously defined, means achieving competitive rates over time at the same time providing the best practicable combination of price, quality, and service. Therefore, LEI used this as the main criterion. LEI also used the other guiding principles (specified in Section 4.1) relevant to the electric co-ops in its evaluation.

4.3.1 Ratemaking process

The rate-setting process for electric co-ops is different from the IOUs. One key difference is that the co-ops in the State are not under KCC jurisdiction in terms of rate approval. The elected Board represent and balance the consumers' and the co-op's interests, which creates a certain degree of self-regulation.[156] The Board decides on whether to raise electric rates and approve the rate change. They are responsible for ensuring electric rates are adequate to maintain the co-op's financial health. The other differences are discussed throughout this section.

A rate study is only performed when needed. The Board hires an independent consultant to conduct a Cost of Service Study. The KCC has guidelines on hiring an independent rate consultant for COSS, and co-ops follow these guidelines. Under the Study, the consultant assesses the co-op's rate classifications and costs for providing electric service. The consultant studies the operations, financing, projected load, future projects, cost per rate class, and revenue requirements.

Then, the consultant evaluates the existing data to determine what revenue is required to operate the co-op in the future. The Study also recommends the appropriate allocation of costs across all rate cases. In the Cost of Service Study, the costs of providing services to each rate class are broken down, given the different load and service characteristics of each class. The Consultant then presents its recommendation to the Board. The Board then acts on the recommendation and determines how to implement the rate design. The Board then informs the members of the potential changes to the rates. They are required by Kansas law to provide a notice of time and

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[155] Ibid.

[156] Guides for Electric Cooperative Development and Rural Electrification, P. 3.

place of any board meeting during which rates will be discussed and voted on, ten days before the meeting.[157] A comment period is set so members can provide their comments. The Board then votes on the rate changes in a meeting open to the members. Figure 78 shows the process of rate-setting for a co-op.

Figure 78. Rate-setting process for electric co-ops

Source: Kansas Electric Cooperatives, Inc. ("KEC")

4.3.2 How revenue requirements are determined

Similar to an IOU, an electric co-op's key revenue requirements include costs associated with purchased power, depreciation, interest, O&M, general, and administrative expenses. One key difference between the IOU and co-op is that there is no return on equity that is factored into the tariff in the co-op's revenue requirements. A co-op's equity is held primarily by its customer-members, who make contributions for service without an expectation of return. However, the co-op operates with an annual revenue margin to make it eligible for financing or compliant with loan covenants.

The revenue requirements of a co-op are set using a Times Interest Earned Ratio ("TIER") level. This is also referred to as the Coverage Ratio, operating TIER, debt service coverage ratio, or modified DSC ratio. The TIER considers the margin plus other factors such as long-term interest expense, depreciation, and amortization, non-operating margins (interest), and cash receipt of patronage capital. The TIER reflects the co-op's revenues and expenses but not the equity costs.[158] It is a measure of the co-op's ability to generate sufficient revenues from operations to be able to

[157] Western Cooperative Electric 2020 Rate Change. P. 6.

[158] Ibid.

pay its long-term debt. Conversely, a very high ratio could indicate excess revenues are being generated by the co-op.

The primary components of the revenue requirement of a co-op are:

1) **Interest expense:**

   a) Capital structure helps to determine how much debt the co-op can carry. A higher debt-capital ratio increases the interest expense and, thus, the revenue requirements. This is the opposite of an IOU, which can increase leverage to lower the WACC.

   b) Interest rates are generally low for co-ops. Co-ops have access to low-cost debt from public and private sources, enabling them to lower their financing costs.

2) **TIER level –** TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the sum of net income and total interest expense by total interest expense. Net income is mainly operating margin in the case of a co-op.

$$TIER = (Interest\ Expense + Margins)/(Interest\ Expense)$$

   The ratio measures how many times a co-op can cover its interest expenses from its pre-tax earnings. The revenue requirement for an electric co-op is set so that it earns sufficient margins to achieve the target TIER level. The margins enable the co-op to maintain financial stability and fund capital expenditure without incurring more debt. TIER is approved by the co-op's member-elected board of trustees. Rural Utility Service's ("RUS") loan documents contain a threshold that must be maintained. According to KEC, "failure to maintain this threshold results in a directive from RUS to the co-op for a remedial plan outlining how they plan to achieve the required level."[159]

3) **Operating costs –** the same as for IOU, except for tax expenses. These are lower for co-ops because they are exempt from federal income taxes.

4.3.3 Cost recovery mechanisms

In addition to recovering costs through their revenue requirements, co-ops in Kansas also include various riders and/or surcharges in customer bills. These riders aim to recover costs that are not recovered through the revenue requirement process. Similar to the IOUs, co-ops charge TDC and ECA. In addition to these two, they also charge the following:

- **Automated Metering Infrastructure ("AMI") Conversion rider,** which is a rider used to recover costs associated with automatic electric meters and supporting systems, is applicable to all rate schedules which include any of the following components: demand

[159] Email correspondence with Mr. Doug Shepherd Vice President, Management Consulting Services at Kansas Electric Cooperatives, Inc. on November 14, 2019. Please also note that the TIER ratios for the various co-ops are not publicly available.

charges, power factor billing or other power factor adjustments, time and temperature-determined rate differentials, or demand determination.

- **Primary Metering and Customer Transformation Discount Rider** is a discount rider applied to any customer operating under rate schedules including "General Service Large, General Service Large – Time of Day, General Service Hearing, or Oil Field Service" and is taking service equal to or above 7.000 volts phase to ground. The discount ranges from 1% to 2% depending on where the customer is receiving service.

In addition to these riders, the customary monthly bills of co-op customers include an energy and customer charge, along with a demand charge (for commercial and industrial customers), all of which are discussed in detail in Section 4.2.4.

4.3.4 Co-op electricity prices

Average electricity prices for co-ops in Kansas have gradually increased over the last several years, as illustrated in Figure 79 below. In 2018, rates for residential customers was the highest, followed by rates for commercial and industrial customers. The average growth rate was highest for the commercial customers at 2.7% per year, followed by residential customers then industrial customers at 2.5% and 1.2% per year, respectively.

Figure 79. Average electricity prices of co-ops in Kansas (cents/kWh)

Note: Electricity rates above were based on the rates of co-ops that are solely serving that particular state. LEI removed the co-ops that served multi-states. The list of these co-ops is shown in Figure 84.

Source: Commercial third-party database (Accessed on November 11, 2019)

When compared to the electric prices of other co-ops in the region, Kansas co-op electricity prices were above the regional average in 2018 for all residential, commercial, and industrial customers.

The average electricity prices in Kansas were higher by 20% to 36% than the regional average, depending on customer type. The largest difference to the regional average (36%) was for industrial customers. Co-ops in Kansas also have the highest average electricity price for commercial customers in the region, as shown in Figure 81.

Figure 80. 2018 Average residential electricity prices of co-ops in the region (cents/kWh)

Note: Electricity rates above were based on the rates of co-ops that are solely serving that particular state. LEI removed the co-ops that served multiple states. For the list of co-ops used for each of the state, please see Section 10 (Appendix A).

Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 81. 2018 Average commercial electricity prices of co-ops in the region (cents/kWh)

Note: Electricity rates above were based on the rates of co-ops that are solely serving that particular state. LEI removed the co-ops that served multiple states. For the list of co-ops used for each of state, please see Section 10 (Appendix A).

Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 82. 2018 Average industrial electricity rates of co-ops in the region (cents/kWh)

Note: Electricity rates above were based on the electric prices of co-ops that are solely serving that particular state. LEI removed the co-ops that served multiple states. For the list of co-ops used for each state, please see Section 10 (Appendix A).

Source: Commercial third-party database (Accessed on November 11, 2019)

4.3.5 Evaluation of the effectiveness of the ratemaking practices

For the co-ops, the evaluation of the effectiveness of the current ratemaking practices is slightly different from the IOUs, given different ownership structures and characteristics. Sub. for SB 69 specifically noted to assess whether the current ratemaking process is in the public interest, which is defined as achieving competitive rates over time while providing the best practicable combination of price, quality, and service. Therefore, for co-ops, LEI used this as the main criterion. LEI has also used the other relevant guiding principles specified in Section 4.1.

With regard to the principle of economic efficiency, the residential electric rates of co-ops (that are operating only in Kansas) have been increasing over the last ten years. As shown in Figure 83 below, between 2009 and 2019, residential retail electric rates for co-ops in the State increased by approximately 2.5% per year. In 2018, residential electric rates for co-ops operating only in Kansas ranged from 11.2 to 17.3 cents per kWh.

Nevertheless, the higher co-op electricity rates do not necessarily reflect inefficiencies or ineffectiveness of the ratemaking practices. Co-ops exist to bring electricity to rural areas that IOUs are reluctant to serve. In general, these areas have a lower number of customers per area (or customer density), which means that more infrastructure investments are needed to reach load centers.

In terms of cost causation and avoidance of cross-subsidies, co-ops hire a consultant to conduct a cost of service study designed to ensure that customers that cause a cost to be incurred pay for that cost. Therefore, as long as this approach is consistently followed, LEI would conclude that the co-op's ratemaking process conforms to that principle.

Figure 83. Average residential retail electric rates for co-ops operating only in Kansas

Note: The average values include average prices for the 22 co-ops that solely operate in Kansas. These co-ops include the co-ops listed in Figure 84 below.

As shown in Figure 84, the various co-ops operating only in Kansas had an average retail electric rate of 14.5 cents/kWh. Moreover, these co-ops have higher average 2018 retail electric prices (across all customer classes) of 14.54 cents/kWh in comparison with IOU and muni rates in Kansas, which have average retail electric rates of 10.73 cents/kWh and 9.3 cents/kWh, respectively.

Figure 84. 2018 average residential retail electric price for co-ops operating only in Kansas

Source: Commercial third-party database (Accessed on November 11, 2019)

Another major factor in evaluating the effectiveness of the ratemaking practices of the co-ops is whether they ensure public interest (e.g., customer focus and bill impacts). The ownership nature of co-ops in terms of being owned by the very customers they serve is conducive to promoting the public interest. As discussed, the co-op board, which decides on the rates, is democratically elected by the members it serves.

Moreover, members are encouraged to participate in ratemaking processes by attending meetings and presentations. Furthermore, co-ops have capital credits that are paid to members when the board decides it to be appropriate to do so. Capital credits are incurred when revenues exceed the cost of providing service. Thus, LEI can conclude that there are sufficient organizational and economic incentives for co-ops to set rates in a way that prioritizes the public interest.

Lastly, according to the information collected by LEI from the KCC, there has been only one complaint involving a co-op to date (the 2013 Lyon-Coffey Complaint), which resulted in a staff investigation, hearing, and Commission Order.[160] The investigation of this complaint, which was conducted by the KCC staff, found that Lyon-Coffey's rate change at the time was not unjust and unreasonable.[161] Specifically, the KCC staff noted that "the revenue requirement and rate design decisions made by Lyon-Coffey are reasonable under the circumstances and consistent with the cost of service principles typically utilized to set rates by other cooperatives in Kansas and the Commission itself."[162] This shows that co-op customers, in general, do not object to the rate increases in their area.

4.4 Municipal utilities

Municipal utilities ("munis") are utilities owned by the cities or towns they serve. Munis are governed by the city council or local board, which is responsible for setting utility rates and service policies alongside public participation. Municipal utilities are typically exempt from most taxes and in-lieu-of-taxes make payments or transfers to a general fund owned by their respective city.[163] While most public utilities, including munis, typically own only distribution infrastructure and purchase electricity and transmission services at wholesale from other owners, certain munis own and operate generation, transmission, and distribution infrastructure.[164]

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[160] Please refer to the 2014 Lyon Coffee Complaint in Docket No. 13-LYCE-514-MIS at http://estar.kcc.ks.gov/estar/portal/kscc/page/docket-docs/PSC/DocketDetails.aspx?DocketId=61d1fd88-3098-4cba-93b7-015b61dda85f

[161] Ibid.

[162] The State Corporation Commission of the State of Kansas. In the matter of a petition for investigation of rates, joint rates, tolls, charges and exactions, classifications and schedules of rates of Lyon-Coffey Electric Cooperative, Inc., pursuant to K.S.A. 66-104d(g). Docket No. 13-LYCE-514-MIS. <http://estar.kcc.ks.gov/estar/ViewFile.aspx/20131203171200.pdf?Id=d22ff57b-572b-4ec0-99ca-0c401ec092fe>

[163] American Public Power Association. *Public Power for Your Community*. 2016.

[164] Ibid.

Key attributes of municipal utilities include public ownership, local control, nonprofit operations, low-cost structure, and a customer focus. Figure 85 below provides a detailed summary of the key attributes of municipal utilities. Similar to co-ops, munis in the state of Kansas do not fall under KCC jurisdiction with regards to rate approval. Instead, munis are regulated by their local government as they strive to provide the *"least-cost and most reliable service over maximizing profit."*[165]

As discussed previously, the three largest munis in Kansas by customer count are as follows:[166]

- **Kansas City Board of Public Utilities ("BPU")** serving approximately 65,500 customers in Kansas City, Kansas and the Wyandotte County;
- **Garden City Electric Utility System ("Garden City")** serving over 11,600 customers in Garden City, located in Southwest Kansas; and
- **Gardner Utilities Department ("Gardner")** serving nearly 8,600 customers in the City of Gardner, located in Northeast Kansas.

Figure 85. Key attributes of municipal utilities

Source: American Public Power Association. *Public Power for Your Community*. 2016.

[165] Kansas Municipal Utilities. "Benefits of Municipal Utilities." <https://www.kmunet.org/page/Benefits>

[166] Note: customer counts are as of February 2019. Source: Kansas Municipal Utilities. *Testimony Provided to the Senate Utilities Committee in Opposition to Senate Bill 69.* February 19, 2019.

Similar to the co-ops, munis were evaluated based on whether their current ratemaking process is in the public interest, which as previously defined, means achieving competitive rates over time while providing the best practicable combination of price, quality, and service. Therefore, LEI used this as the main criterion. LEI also used the other guiding principles (specified in Section 4.1) relevant to munis in its assessment.

4.4.1 Ratemaking process

Unlike IOUs, munis are not under the jurisdiction of the KCC.[167] Municipal utilities in Kansas implement rates (and associated rate adjustments) in accordance with approved municipal codes or ordinances. Municipal rates are set using a cost of service methodology and are expense-based, such that munis are able to recover the costs associated with providing electric service to their customers, as well as other O&M costs. When munis are nonprofit utilities, they do not earn a return on rate base. However, the munis might not have the same level of independent oversight as investor-owned utilities, which can create opportunities for poor management or politically-motivated use of utility budgets.

Generally, the rate-setting process for munis follows many of the same steps utilized by co-ops. These include hiring an independent consultant to conduct a cost of service study, making recommendations to the relevant regulatory body (which usually takes the form of a Board, Commission, or Committee), a period whereby stakeholders are free to comment, and concluding with a final decision that can be petitioned for review. These steps are highlighted in Figure 86 and discussed in more detail below. Typically, the rate-setting process takes around nine months to complete.

The rate adjustment process for ***Kansas City BPU*** is governed by the Unified Government Charter Ordinance.[168] Accordingly, once the independent consultant completes the cost of service study (Step 1 in Figure 86), BPU conducts public hearings to review the findings (comprising Steps 2 and 3). The hearings process is initiated with a 90-day notice issued to customers wishing to intervene, usually composed of industrial consumers. Once the hearings commence, employees and representatives of the BPU, external consultants and utility customers can present their positions and engage in cross-examination. Upon conclusion of the public hearing, transcripts of these proceedings are then turned over to the Board for the decision, along with all of the testimonies and evidence presented (Step 4). After the Board has examined all hearing documents and rendered a rate adjustment decision, customers have 30 days in which to petition a review from the Wyandotte County District Court (Step 5). The Court has the power to vacate the Board's decision; should it be determined that the rate adjustment was not just or reasonable.

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[167] KCC. "Jurisdictional Utilities." <https://kcc.ks.gov/about-us/jurisdiction>

[168] Kansas City Board of Public Utilities. *Submitted Testimony Provided to the Senate Utilities Committee [Senate Bill 145].* February 18, 2019.

Figure 86. Rate setting process for municipal utilities

The ***Garden City*** ratemaking process follows a similar process, except that following completion of the cost of service study (Step 1), the independent consultant makes recommendations in an open meeting to the city's Public Utility Advisory Board, which is comprised of nine members appointed by the Commission (Steps 2 and 3).[169] Following a thorough review, the Board then provides comments to the City Commission, which consists of five members elected by the citizens of Garden City. It is here that the Commission makes a final decision on the rate adjustment, through a series of three open meetings (Step 4).

Gardner follows the same process as that of Garden City, differing only in terms of the regulatory bodies which are tasked with reviewing and rendering decisions on rate adjustments. For example, independent consultants make recommendations to the city's Utility Advisory Commission instead, which is comprised of five members appointed by Council.[170] The cost of service study is also reviewed by the Commission's Rates Subcommittee. The final stage of review is conducted by the City Council, comprising five members and the Mayor, all of whom are elected by citizens. The City Council reviews the evidence and recommendations through two meetings open to the public and press, at which point a final decision is made.

In terms of revenue requirements, these are determined to enable munis to cover the costs associated with providing electric service to customers, as well as operating costs. Munis do not calculate rate base as a component of their revenue requirements, and instead, include their 5-year capital improvement plans ("CIP") and riders in their calculations. For example, BPU's most recent CIP identified $220.5 million in generation, transmission, and distribution projects, which it seeks to prioritize and schedule over the foreseeable future.[171]

4.4.2 Cost recovery mechanisms

In addition to the 5-year CIP, which munis incorporate into their revenue requirements, munis such as Kansas City BPU also include various riders and surcharges. These riders are added to

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[169] Data received from the Kansas Municipal Energy Agency on October 11, 2019.

[170] Ibid.

[171] Kansas City Board of Public Utilities. *Comprehensive Annual Financial Report.* Fiscal years ending December 31, 2018 and 2017.

customers' utility bills in order to recover portions of BPU's costs.[172,173] Figure 87 lists the other riders charged by munis in Kansas.

Figure 87. Other riders charged by munis in Kansas

Riders	Description
Energy Rate Component rider	rate applied to the amount of energy consumed by the customer and is implemented to recover fuel costs, purchased power costs, as well as other ancillary costs
Environmental Surcharge	applied on an annual basis to recover capital investments made to meet local, state, and federal environmental regulations
Customer Access Charge	recovers a portion of costs associated with providing system access and customer service (including costs for meter reading, bill calculation, postage, as well as basic plant investments in meters, transformers, and service lines)
Facilities Charge	a monthly charge based on the customer's demand, designed to recover the capital costs incurred to distribute electricity
Other riders for payments-in-lieu-of-taxes ("PILOT")	5-15% of BPU's gross revenues are paid to the Unified Government of Wyandotte County and Kansas City, Kansas, as well as other optional riders such as the electric rate stabilization rider, and the reactive adjustment, which applies only to small, medium, and large general service and large power service customers.

Note: According to BPU's 2018 Rate Application Manual, the electric rate stabilization rider "shall only be applied in appropriate circumstances, including but not limited to, situations where the Utility has a need for revenues recovered under the rider that cannot be timely recovered through other means, situations where the Utility is suffering an operating cash shortage, situations where failure to apply the rider would result in economic loss or other financial harm to the utility, emergency situations and other situations where the application of this rider to recover a qualified expenditure is in the best interests of the utility as determined by the Board." (Source: Kansas City Board of Public Utilities. Rate Application Manual. Rates effective January 1, 2018.)

Sources: Kansas City Board of Public Utilities. Rate Application Manual. Rates effective January 1, 2018, and Kansas City Board of Public Utilities. Understanding the BPU Billing Statement.

The major riders/surcharges utilized by BPU are the ERC rider and the ESC. On the other hand, Garden City includes a flat monthly customer charge in its billing process, in addition to an energy charge.[174] This customer charge is enabled through Garden City's Code of Ordinance. Figure 88 below tracks Garden City's current monthly customer charge by customer class.

For Gardner, customers are similarly charged a flat monthly service charge enabled through Gardner's Municipal Code.[175] The service charge for each customer class is as follows:

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[172] Kansas City Board of Public Utilities. *Rate Application Manual.* Rates effective January 1, 2018.

[173] Kansas City Board of Public Utilities. *Understanding the BPU Billing Statement.*

[174] Note: large general service customers are subject to an additional flat demand charge of $11.86. Source: Municipal Code. "Article V. – Electric Utility." <https://library.municode.com/ks/garden_city/codes/code_of_ordinances?nodeId=CD_ORD_CH90UT_ARTVELUT>

[175] Gardner Municipal Code. "Chapter 13.25 – Electric Rates (Effective until January 1, 2020." <https://www.codepublishing.com/KS/Gardner/#!/Gardner13/Gardner1325.html>

$6.72/month for residential customers, $7.35/month for commercial customers without a demand charge, $16.70/month for commercial customers with a separate demand charge, and $22.26/month for large commercial customers.[176] All customers are also subject to a power cost adjustment, which increases or decreases electric charges for each billing period to recover costs associated with purchasing wholesale power, as well as fuel costs.[177]

Figure 88. Garden City's customer charge by customer class

Source: Municipal Code. "Article V. – Electric Utility." <https://library.municode.com/ks/garden_city/codes/code_of_ordinances?nodeId=CD_ORD_CH90UT_ARTVELUT>

4.4.3 Munis electricity prices

Electricity rates of munis in Kansas have been relatively flat for the past several years, as shown in Figure 89. The historical average residential electric rates for Kansas munis between 2009 and 2018 increased by only an average of 1% per year. In the same time period, the historical average commercial electric prices for Kansas munis increased by only 0.4% per year, while electric prices for industrial customers declined by 0.1% per year.

[176] Ibid.

[177] Ibid.

Figure 89. Historical average residential, commercial, and industrial electricity prices for Kansas munis, 2009-2018

Note: For the list of munis included in the calculation of the average electricity prices above, see Section 11 (Appendix B).

Source: Commercial third-party database (Accessed on November 11, 2019)

Compared to the other munis in the region, Kansas has the highest average residential and commercial electricity prices. The average electricity prices were higher by 14% and 15% for residential and commercial customers, respectively, as shown in Figure 90 and Figure 91. The average electricity price for industrial customers was also higher by 4% than the regional average in the State (Figure 92), but it was not the highest in the region.

Figure 90. 2018 average residential electricity prices for munis in the region

Note: For the list of munis included for each state, please see Section 11 (Appendix B).

Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 91. 2018 average commercial electric prices for munis in the region

Note: For the list of munis included for each state, please see Section 11 (Appendix B).
Source: Commercial third-party database (Accessed on November 11, 2019)

Figure 92. 2018 average industrial electric prices for munis in the region

Note: For the list of munis included for each state, please see Section 11 (Appendix B).
Source: Commercial third-party database (Accessed on November 11, 2019)

4.4.4 Evaluation of the effectiveness of the ratemaking practices

Similar to the IOUs, LEI evaluated the effectiveness of the ratemaking practices of the munis by looking at the guiding principles discussed in Section 4.1. These include provision of reliable electric service at a reasonable cost to consumers (or economic efficiency and performance),

balance the interests of utilities, with respect to cost recovery and reasonable return on capital investment, and consumers with regard to fair and affordable rates, customer focus and bill impacts, stability of the sector, cost causation and avoidance of cross-subsidies, evolving utility structure to facilitate innovation and regulatory simplicity.

Munis' ratemaking practices provide reliable electric service at a reasonable cost to consumers. This is also the mission of munis, which, as mentioned previously, involves providing the least-cost and reliable power to customers. It is clear that the three munis currently under review have been providing reliable electric service. For example, Kansas BPU was awarded the American Public Power Association's ("APPA's") Reliable Public Power Provider ("RP3") Platinum designation in 2018.[178] Garden City earned the RP3 Gold designation in 2017.[179] The RP3 designation "recognizes public power utilities that demonstrate proficiency in four key disciplines: reliability, safety, workforce development, and system improvement."[180]

Figure 93. Historical retail rates for munis, 2009-2018

Source: Kansas Municipal Utilities

As for providing reasonable cost to consumers, this can be confirmed by comparing average rates for the three municipal utilities under review with the average rates of IOUs and co-ops operating in Kansas. In 2018, retail rates for Kansas City BPU, Garden City, and Gardner (across all customer classes) averaged 9.3 cents/kWh. This is lower than both IOU and co-op rates in the state of

[178] Kansas City Board of Public Utilities. *Submitted Testimony Provided to the Senate Utilities Committee [Senate Bill 145].* February 18, 2019.

[179] Garden City Kansas. "Electric." <https://www.garden-city.org/government/departments/public-utilities/electric>

[180] Ibid.

Kansas, which in 2018 averaged 10.73 cents/kWh and 13.77 cents/kWh, respectively.[181] Customers of the three munis under review also enjoy relatively stable rates, as demonstrated in Figure 93, which illustrates retail rates for Kansas City BPU, Garden City, and Gardner from 2009 to 2018.

This stability in retail rates generally holds across all customer classes, as can be seen in Figure 94, which breaks down average retail rates for the three munis by customer class for the 2009 to 2018 period.

Figure 94. Retail rates for munis by customer class in Kansas, 2009-2018

Source: Kansas Municipal Utilities

Munis' ratemaking process is simple and provides opportunities for stakeholders to comment. It is also assumed that with the hiring of an independent consultant, the issue of cross-subsidies is mitigated. However, the lack or reduced oversight by an independent entity can create opportunities for poor management decisions or misguided investment decisions.

A final approach for assessing the effectiveness of the muni's ratemaking practices involves evaluating the frequency of rate adjustments, as well as whether these decisions have been appealed or petitioned for review. In the case of Kansas City BPU, there have been six rate changes in the past ten years (in the years 2010, 2011, 2012, 2013, 2017, and 2018).[182] Of these six decisions, none were petitioned for review by the Wyandotte County District Court.[183] As for Garden City, there have only been two rate changes in the past ten years – one in 2013 and another

[181] Note: IOU average taken as the average retail rates for residential, commercial, and industrial customers served by Kansas City Power & Light Company, Kansas Gas and Electric Company, and Westar Energy. Source: Data received from Evergy on November 5, 2019.

[182] Data received from the Kansas Municipal Utilities on October 25, 2019.

[183] Kansas City Board of Public Utilities. *Submitted Testimony Provided to the Senate Utilities Committee [Senate Bill 145].* February 18, 2019.

in 2016.[184] Finally, for Gardner, there have been two rate changes in the past ten years (in the years 2009 and 2013), as well as an upcoming rate adjustment becoming effective in January 2020.[185] The 2020 rate adjustment will see electric rates reduced by 2% for residential customers, as well as a reclassification of commercial customers from with/without a demand charge to a new structure of small, medium, or large commercial class, as determined by their energy demand level.[186]

4.5 Key observations

LEI evaluated the effectiveness of current ratemaking practices in Kansas in light of the overarching objective of achieving regionally competitive rates and reliable electric service, as stated in substitute for SB 69. In doing so, for IOUs, the Project Team evaluated the effectiveness of ratemaking practices in terms of attracting adequate capital investments (and discouraging unnecessary capital investments), balancing utility profits with public interest objectives of achieving competitive rates and reliable service, recovering from consumers the partial or full costs of investments no longer used or required to be used. For co-ops and munis, the Project Team's evaluation focused on assessing the extent to which ratemaking practices serve the public interest and achieve reasonable rates. Based on a thorough, comprehensive analysis across these areas, the Project Team identified areas of strength and areas of weaknesses in Kansas' current ratemaking practices.

4.5.1 Strengths

- **Current ratemaking practices for IOUs have attracted adequate capital investments in Kansas:** as evidenced by Evergy's ability to raise debt and equity ($2.5 billion in non-convertible debt issued since August 2018 and $270 million in common equity issued since 2016), the ratemaking practices for IOUs in Kansas have been performing well in terms of enabling appropriate attraction of capital.

- **Current ratemaking processes for Kansas electric co-ops and munis are in the public interest:** as discussed in Sections 4.3.1. and 4.4.1, co-ops and munis in Kansas have very similar ratemaking processes that ensure the primacy of consumer interests. Co-ops are owned by the customers they serve and governed by a democratically elected board whose primary responsibility is to represent the interests of the customers it serves. Similarly, munis are owned by the cities or towns they serve, thereby fostering accountability to their local community. Moreover, the ratemaking process of both co-ops and munis encourages the participation of members in the ratemaking process through stakeholder meetings or hearings. In the last ten years, the one instance in which a formal complaint was filed against a co-op (the 2014 Lyon Coffee Complaint) also found that the

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[184] Data received from the Kansas Municipal Utilities on October 25, 2019.

[185] Gardner. "Utility Rates." <http://www.gardnerkansas.gov/government/departments-and-divisions/utility-rates>

[186] Ibid.

rate change at the time was not unjust and unreasonable. Overall, the ratemaking process for co-ops and munis in Kansas is effective in terms of ensuring the public interest in terms of providing low cost and reliable electric services.

4.5.2 Areas of improvement

- **Imbalance between utility profits and public interest objectives of achieving competitive rates:** as previously discussed, retail electric rates of the two largest IOUs in Kansas (Westar Energy and KCP&L) have been increasing over the past decade by approximately 45.8% and 48.9%, respectively, between 2009 and 2018. Moreover, when compared to similar, vertically integrated utilities in regional states, both Westar and KCP&L have above average residential, retail rates (specifically, 20% and 22% higher than average in 2018, respectively) which indicates that there is room for improvement in terms of lowering rates (provided they remain cost-reflective) to ensure that they are regionally competitive.

- **Recovery, by Kansas electric ratepayers, of the full or partial cost of investments no longer fully used or required to be used in service to the public within Kansas:** while the KCC's primary objective standards (as noted in K.S.A 66-128 et seq. and K.S.A 66-1239) and vetting process for ensuring the prudence of utility investments are sound, currently, ratepayers in Kansas continue to pay for utility investments that are ***not fully utilized*** (mainly coal plants) due to increasing competition from low-cost resources, primarily, wind. This is evidenced by capacity factors (mainly of coal and, to some extent, natural gas) that are declining and, in some cases, below the regional average for plants of similar age (Jeffrey Energy Center and La Cygne coal plants). Between 2007 and 2018, the average capacity factor for coal plants in Kansas declined by 29%. Moreover, in 2018, the average capacity factor of coal plants in Kansas was approximately 5% lower than the regional average. This indicates that the relative competitiveness of coal plants in Kansas is declining in relation to other low-cost resources in SPP's IM's centralized wholesale market. While Kansas' natural gas plants perform relatively better in terms of capacity factors, the Osawatomie natural gas plant (GT) is significantly underutilized with a capacity factor of approximately 73% below the regional average. In this regard, the effectiveness of current ratemaking practices in Kansas can be improved by ensuring regular evaluation of utility investments, potentially through an IRP process.

- **Recovery of utility costs through surcharges and riders, without a comprehensive ratemaking process:** Of all the legislatively mandated and commission-authorized riders (including ECA, EER, and AVTR), the ECRR represents the highest share of the overall bill, with an average of approximately 35.9% for Westar Energy between 2009 and 2018 and ECA for KCP&L with an average of 15.2% per year during the same period. Also, as discussed in detail in Section 4.2.5, the legislatively mandated TDC (mandated in K.S.A 66-1237), which enables utilities to recover SPP-related transmission costs, has been increasing for the past several years, further driving rising costs to ratepayers. While the KCC does review the TFR issued to the SPP by Kansas IOUs to ensure consistency with SPP's Revenue Requirements and Rates file, SPP has the primary responsibility for assessing and evaluating each utility's ATRR which determines the utility's revenue requirements based on its LRS within SPP. Moreover, as noted in Section 4.2.5.3, the

FERC-authorized return on transmission-related revenue requirements are typically higher than what is authorized by the KCC for an IOU's base rate revenue requirement.[187]

[187] LEI is aware of Senate Bill 24 which was introduced on January 17, 2019 and referred to the Committee on Utilities on February 28, 2019. Senate Bill 24 aims to amend K.S.A 66-1237 and repeal the existing section.

5 Comparative analysis of laws, regulations, and oversight in surrounding states

While all US states are unique with respect to resource endowment, economic activity, and approach to electric supply, there are lessons to be learned through comparative analysis. As part of the enacted law, the Kansas legislature seeks that the study evaluate whether electricity providers in surrounding states are subject to state laws, regulations, and oversight similar to such requirements in Kansas.[188] As such, this comparative analysis corresponds to Task 1.6 in the proposed workplan and aims to answer the following questions to evaluate the query posed in the law effectively:

- What is the current **institutional framework** in surrounding states?
- What is the current **policy framework** for electricity supply in surrounding states?
- What is the current **legal framework** as it pertains to governing electric supply?

In each of the selected states, we seek to highlight the important features of the electricity supply industry and identify key issues and lessons arising from a detailed review of each state. In this section, we preview the selected states for comparison and address the rationale for their selection.

Effectiveness of case study and comparative analysis

In general, case studies refer to long-form investigations where multiple interacting variables require holistic analysis. Through a case study, the researcher may go beyond quantitative data and understand the qualitative factors in the subject/actor's perspective. Thus, case studies are most useful in policy, social, and education situations, where a variety of interacting factors require a holistic analysis to draw conclusions from.

Similarly, comparative analysis research in social sciences entails identifying the similarities and differences amongst selected study groups. The literature notes that properly identifying these factors aids the researcher in "understanding, explaining and interpreting diverse historical outcomes and processes" and applying them to current contexts.

Sources: Merriam, Sharan B., and Elizabeth J. Tisdell. *Qualitative research: A guide to design and implementation.* John Wiley & Sons, 2015; Ragin, Charles. C. *The Comparative Method: Moving beyond Qualitative and Quantitative Strategies*. Berkeley, 1987.

[188] Kansas Legislature. *Substitute for SB 69 by Committee on Utilities - Requiring an electric rate study of certain electric utilities.* April 18, 2019.

5.1 Overview of the selected jurisdictions

In identifying the states for comparable analysis, LEI first considered the geographic location of Kansas, creating a long list with all the US states within the US Census Bureau regions that surround Kansas i.e., "West North Central" "West South Central" and "Mountain" regions. Following this long list, LEI identified key characteristics to narrow the longlist into a shortlist of eight states, using the following criteria:

- States that have **significant quantities of renewables** in their energy mix;
- States with **multiple utility ownership models** serving their customers;
- States with a **mix of rural and urban** customers; and
- States with **notable natural resource extraction** industries.

The final list also mirrored the list of states that were identified for comparison by KCC and the IOUs for their respective rate studies, with LEI considering the unique circumstances of each state that would warrant their inclusion and make for useful comparisons to Kansas. This process is summarized in Figure 95 below.

Figure 95. Selection process to identify jurisdictions to study

Although Kansas is the third largest State in terms of size, it is firmly in the middle (5th) with respect to installed capacity. With respect to demand and population density, it ranks among the lower states, which is an expected outcome. Nearly all the selected states participate in an ISO, with most states either part of the SPP or MISO markets. Figure 96 provides the key statistics of the states covered in this Study.

Figure 96. Key statistics across selected states

Jurisdiction	Installed capacity (MW, 2017)	Demand (TWh, 2017)	Area (sq.km)	Population (2018)	Population density (2018, ppl/sq km)	ISO Participation
Arkansas	14,642	46	137,732	3,013,825	22	Yes (MISO & SPP)
Colorado	16,017	55	269,601	5,695,564	21	No
Iowa	17,671	49	145,746	3,156,145	22	Yes (MISO)
Kansas	16,138	40	213,100	2,911,505	14	Yes (SPP)
Missouri	21,809	76	180,540	6,126,452	34	Yes (MISO & SPP)
North Dakota	8,234	20	183,108	760,077	4	Yes (MISO & SPP)
Oklahoma	26,691	60	181,037	3,943,079	22	Yes (SPP)
South Dakota	4,129	12	199,729	882,235	4	Yes (MISO & SPP)
Texas	123,512	402	695,662	28,701,845	41	Yes (ERCOT)

Source: Energy Information Administration, *State Electricity Profiles*. January 2019; US Census Bureau. *Population Estimate (As of July 1)*. 2018.

Figure 97. Map of selected states

Source: Commercial third-party database (Accessed on November 20, 2019)

In the next section, LEI summarizes the selected states and provides more context for their selection.

5.2 Summary of the selected jurisdictions

In this section, LEI looked at the state of the electricity supply industry, including average delivered prices among various customer classes, their utility ownership models, the presence of retail competition, and ratemaking design. It is important to note that there are several factors that drive the industry structure, and external socioeconomic factors such as resource endowment, economic development and population growth will all have an impact on utility ownership, retail prices, annual sales, among others.

A briefing summary of each state under consideration is shown in Figure 98 below, with more detailed analyses in subsequent sections of this paper. In each of the subsections detailing the states, we consider the institutional, policy, and legal framework of each state and conclude with key takeaways for Kansas.

Figure 98. Briefing summary on selected states

Jurisdiction	Selection Rationale	Briefing notes
Arkansas	▪ Large **coal and gas fleet** which provide a bulk of electricity for consumers	▪ Arkansas is the **smallest geographical state considered**, with abundant natural gas reserves, and thermal resources provide most of the electric power ▪ **Majority of electric consumption is by industrial and residential consumers**, each at 37% ▪ There is no retail competition in Arkansas, and all distribution utilities have exclusive franchise
Colorado	▪ Neighboring state to Kansas with a large variety of electric suppliers e.g. IOUs and co-ops ▪ Strong renewables sector	▪ Colorado is a diverse state with substantial oil, gas and coal reserves; **thermal resources (coal and gas) provide over 75%** of all electric generation ▪ IOUs comprise just over half of all retail sales, while coops account for more than 27% of sales. The bulk of electric consumption is in the commercial sector, comprising 38% of all sales
Iowa	▪ Similar topology and economic activity ▪ Second largest share of wind generation after Kansas	▪ As in Kansas, in Iowa **both coal-fired and wind generation** comprise large shares of total generation; coal comprises 44% while wind accounts for 37% ▪ Major IOUs account for 75% of all retail sales, while coops and munis account for 14% and 11% respectively
Missouri	▪ Neighbors Kansas, and shares parent IOU holding company ▪ Large thermal fleet, primarily coal	▪ Missouri is a large transportation hub and has a **large thermal fleet**; coal-fired generation accounts for 80% of all generation in the state ▪ IOUs account for two-thirds of all retail sales, with coops serving 19% of other customers
North Dakota	▪ Significant oil and gas extraction industry ▪ Diversity of suppliers such as IOUs and coops	▪ North Dakota is the second largest oil producing state, and **industrial customers comprise majority** of the retail sales in the state ▪ As in Kansas, **coal-fired and wind generation comprise most** of the electric generation, with coal accounting for 64% and wind 27% ▪ Coops comprise more than two-thirds of all retail sales in the state.
Oklahoma	▪ Neighboring state with significant thermal and wind generation ▪ Entire state within SPP footprint	▪ Oklahoma has **large natural gas production industry**, driven by shale resource. Thermal generation, primarily natural gas, provides most of the state's electricity ▪ Two IOUs account for nearly 70% of all electric sales, and coops and munis supply 20% and 10% respectively.
South Dakota	▪ Energy mix comprises significant thermal and renewable resources ▪ Diverse suppliers comprising IOU and coop utilities	▪ South Dakota is the smallest state in terms of installed capacity and demand. Generation in the state comprises hydro (48%), wind (27%) and coal (20%) making it the only **majority-renewable state** amongst the comparables ▪ IOUs comprise just under half of all retail sales (48%) while coops and munis comprise the other half at 36% and 12% respectively
Texas	▪ Significant wind resource and installed capacity in the state ▪ Large hydrocarbon extraction industry	▪ Largest geographical state considered in comparables, with **very significant natural gas, coal, and wind-powered generation**; most Texas utilities part of ERCOT power market ▪ Legal framework operates outside of FERC jurisdiction; overseen by PUCT ▪ Electric **retail competition available to all customer classes** within the service territories of IOUs including AEP, CenterPoint and Texas-New Mexico Power

Source: Regulator and utility annual reports; Energy Information Administration, *State Electricity Profiles*. January 2019.

5.3 Key takeaways from the comparable analysis

In general, Kansas appears to have a similar institutional framework to its comparators with exclusive franchises for electric supply, a single regulator with a broad rate-setting jurisdiction, and a combination of member, municipal and investor-owned utilities seen across the region. Kansas's electric policy framework is generally *laissez-faire*, with limited state resources committed to a policymaking role. Smaller state departments with narrow mandates was a general theme across the region, with most of the enforcement roles attributed to the regulator.

As noted earlier, Kansas is unique among the comparator states selected in having neither an IRP process nor a Renewable Portfolio Standard ("RPS"). In this section, we assess the trends that are seen in each state, and their relevance to Kansas. In addition to the high-level discussion of comparable states below, a more detailed overview of each comparable state is provided in Section 12 (Appendix C).

5.3.1 Key takeaways regarding institutional framework

In general, most states considered have similar institutions responsible for the delivery of electricity to customers, i.e., a vertically integrated utility responsible for generation, transmission, and distribution with an exclusive franchise. The regulators across the comparator states all have broad mandates, not just limited to energy utilities. In Kansas, the regulator is responsible for oversight of five industries, including electric utilities. This is not unusual, with a multi-sector oversight mandate seen in all states and illustrated in Figure 99 below.

Figure 99. Regulator mandates across all states

Commission	Electric	Natural Gas	Water	Oil & Gas (extraction)	Pipeline (intrastate)	Telecomm-unications	Transport-ation	Railroads
Arkansas Public Service Commission	Yes	Yes	Yes	No	Yes	Yes	No	No
Colorado Public Utilities Commission	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Iowa Utilities Board	Yes	Yes	Yes	No	Yes	Yes	No	No
Kansas Corporation Commission	Yes	Yes	No	Yes	Yes	Yes	Yes	No
Missouri Public Service Commission	Yes	Yes	Yes	No	No	Yes	No	No
North Dakota Public Service Commission	Yes	Yes	No	No	Yes	Yes	No	Yes
Oklahoma Corporation Commission	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
South Dakota Public Utilities Commission	Yes	Yes	No	No	No	Yes	No	No
Public Utility Commission of Texas	Yes	No	Yes	No	No	Yes	No	No

Source: Regulator websites.

All states except **Colorado** are participants in an RTO, with both SPP and MISO involved in five states each. In Texas, most of the state's utilities are members of ERCOT, which is also an RTO but has very limited interconnection with the rest of the US grid. ERCOT is also unique in that FERC has no jurisdiction over ERCOT.

While ownership models vary, in general, customers receive their supply from either an IOU, co-op, or muni, with shares varying across states. A notable exception is **South Dakota**, where nearly

half (48%) of generation is supplied by hydro-electric plants that are owned by the US Army Corps of Engineers.[189]

For decisionmakers in Kansas, the current institutional framework is not unusual from regional comparators, and the current industry structure offers a firm foundation for the expansion of the scope of any of the roles, e.g., state energy office or utilities division.

Key takeaways: institutional framework

- Existing institutions are **likely sufficient** for effective monitoring and oversight of Kansas utilities. The KCC's role in utilities regulation is consistent with the institutions seen across the comparator states.
- There are **no anomalous entities** in Kansas, and the scope of the existing institutions is consistent with regional states.
- To the extent that a **formal state energy office** may be desirable for increased consumer engagement and broader program delivery, decisionmakers in Kansas may want to consider expansion of the current State Energy Office's role.

5.3.2 Key takeaways regarding policy framework

Across comparator states, Kansas can be considered *laissez-faire*[190] with respect to formal policies and long-term plans from the state; i.e., the state does not issue any guidance on the direction of the sector. In most states considered, utilities are responsible for long-term planning for electricity supply through an IRP process, which is overseen by the regulator and/or is legislatively mandated. Only Kansas, Iowa, and Texas do not have formal IRP planning processes, with other states requiring a regular utility IRP filing. The regularity of the filing is between two to four years, with a planning horizon typically between ten and twenty years.

With respect to customer choice, retail competition is absent in the states considered except **Texas**.[191] Retail competition was introduced in 2002 in Texas, and nearly all (92%) of eligible customers have exercised their ability to switch providers since then.[192]

With respect to long term state energy plans, all states, except South Dakota, have a form of an energy plan, but only four of the states have legislatively mandated energy plans. The mandated

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[189] EIA. *State Energy Profiles. South Dakota.* March 21, 2019.

[190] In economic theory, *laissez-faire* policy approach refers to the principle of minimal government interference into the economic affairs of individuals and society.

[191] Retail choice exist across all customer classes in most of the state.

[192] Public Utility Commission of Texas. Report to the 85th Texas Legislature: Scope of Competition in Electric Markets in Texas. January 2017.

plan in Texas had a noted primary focus on electricity, but with respect to competitiveness. Other states with legislatively mandated energy plans include Colorado, Missouri, and North Dakota. There has not been an energy plan in Kansas since the abolition of the Kansas Energy Council in 2008.[193] A summary of the energy plans and the key topics covered in each state are enumerated in Figure 100 below.

Figure 100. Summary of energy plans in each state

State	Title	Author	Year	Length (pages)	Legislatively mandated?	Key topics covered (non-exhaustive)
Arkansas	Sustainable Energy Resources Action Guide	Arkansas Public Service Commission	2010	24	No	Energy efficiency, smart grid, emerging technologies
Colorado	Colorado State Energy Report	Colorado Energy Office, Department of Natural Resources, Department of Public Health & Environment	2014	30	Yes	Growing jobs and spurring innovation, energy efficiency, alternative fuel vehicles, fossil fuel production, renewable energy, environmental protection, streamlining government, emergency planning
Iowa	Iowa Energy Plan	Iowa Economic Development Authority, Iowa Department of Transportation	2016	100	No	Energy affordability, economic development, energy efficiency, distributed generation (wind, solar), biofuels, enhanced reliability, smart grids, alternative fuel vehicles
Missouri	Missouri Comprehensive State Energy Plan	Department of Economic Development, Division of Energy	2015	302	Yes	Energy efficiency, affordability, reliability, maximizing clean energy, regulatory improvement, innovation, emerging technologies, job creation
North Dakota	Empower North Dakota	EmPower ND Commission	2008, 2016	36, 16	Yes	Increased energy production (oil, coal, biodiesel, wind, biomass), energy efficiency, environmentally-friendly policies, R&D in cleaner technologies
Oklahoma	First Energy Plan	Governor's Office	2011	41	No	Enhanced natural gas and oil production, renewable energy (wind), affordability, energy efficiency, job creation, economic growth
South Dakota	n/a					
Texas	State Energy Plan	Governor's Competitiveness Council	2008	76	Yes	Reliable, balanced, competitively-priced energy supply, energy efficiency and demand response, removing barriers in the competitive market

Source: Regulator websites. Energy Information Administration, *State Electricity Profiles*. January 2019

Policymakers in Kansas should consider the costs and benefits of a legislatively-mandated long-term energy planning process similar to those in comparable jurisdictions. The benefits of an IRP or state energy plan include transparency, stakeholder participation, and least-cost resource planning for utilities and clarity on sector direction for the industry in general. However, there

[193] The last Kansas Energy Report was published on January 7, 2009 (Source: Kansas Energy Council. *Kansas Energy Report*. January 7, 2009).

are increased costs and regulatory burden which must be borne by ratepayers as part of such processes.

Key takeaways: policy framework

- Kansas is one of the few states **without a mandated IRP process**, and a cost-benefit analysis of this process should be considered given the absence of retail competition in the state
- Long-term energy plans performed by the state or regulator can be considered; **stakeholders in Kansas have expressed concern** at the absence of a **long-term policy** in the state

5.3.3 Key takeaways regarding the legal framework

In Kansas, the legal framework principally provides the mandate for the actions of the main regulatory body (i.e., the KCC). The legislature is also used as a policymaking tool, whereby policy actions such as rate studies and renewable policies are enacted in the form of statutes in the absence of a state energy department and/or office with a broader scope. This is in contrast to Missouri, where the Division of Energy has been tasked with the development of the state energy plan.[194]

However, across most jurisdictions considered in the study, Kansas did not have any unusual legal requirements.[195] Most comparator states have similar bicameral legislatures tasked with lawmaking for the state's utilities and establishing the mandate of the regulator. With respect to utility oversight, municipalities and cooperatives were all outside the mandate of the regulator in the comparator states considered.

With respect to renewable energy laws, Kansas has a voluntary renewable portfolio standard ("RPS") goal, which is in line with regional goals. Amongst the comparator states, Kansas has one of the softer renewable targets and is on track to comfortably surpass its voluntary commitment due to the influx of wind generation in the state. Colorado has the most stringent renewable target, with a 30% RPS goal, increasing to 100% by 2050. In contrast, Arkansas has no renewable target while North Dakota, South Dakota, and Oklahoma have voluntary goals, albeit with smaller targets than Kansas. A summary of these standards is illustrated in Figure 101 below.

[194] Missouri Department of Economic Development. *Missouri Comprehensive State Energy Plan.* October 2015.

[195] LEI defines "onerous" as a task that incurs a significantly greater legal burden than would be expected or observed elsewhere.

Figure 101. Renewable and clean energy standards in each state

Source: Adapted from DSIRE. Accessed on November 29, 2019

For decision-makers in Kansas, the existing legal framework is likely sufficient to the extent that it is meeting the current policy objectives of the state. Additional legal actions may be necessary to meet future objectives, but those might come with additional costs. For instance, Kansas created a legal authority in 2006 for transmission development, referred to as the Kansas Electricity Transmission Authority ("KETA"). However, KETA's function was consolidated with the regulator since the role of transmission planning is primarily performed by SPP with member input.[196]

Key takeaways: legal framework

- Existing legal framework is s**ufficient to the extent that it meets the existing policy objectives** of the state. Kansas does not have more onerous requirements than other states.
- An RPS mandate for renewables **has not been the primary driver** for renewable build out in comparator states, and most will meet their targets for reasons other than RPS goals.
- Using statutes and legal frameworks to institute policy goals may not always achieve the desired outcome; the legislature however remains an effective tool to drive changes in the sector, such as a state energy policy, for example.

[196] Kansas Legislature. *Senate Bill No. 318. Kansas Electric Transmission Authority; Federal Clean Power Plan; SB 318.* Approved May 6, 2016.

6 Options available to KCC and the Kansas Legislature

The Sub. for SB 69 enumerated several options to be explored in an effort to help Kansas achieve regionally competitive retail electricity rates and, at the same time, provide "the best practicable combination of price, quality, and service."[197] Figure 102 illustrates a list of these options, which are discussed in the subsections below. It should be noted that these options are not mutually exclusive so that some of the options could be combined.

Since this Study's overarching goal is to provide information that may help future legislative and regulatory efforts in developing an electric policy to achieve regionally competitive rates, LEI considers the legislative enactments and regulatory actions as part of the process, and not as options.

Figure 102. Options available to the KCC and Kansas Legislature to affect retail electricity rates

Source: Sub. for SB 69

LEI evaluated these various options based on four criteria, namely:

- ***Achieve regionally competitive electricity prices:*** The primary purpose of conducting this Study is to look at various ways to help achieve regionally competitive retail electricity prices in Kansas. Comparable neighboring states include Colorado, Iowa, Missouri, Oklahoma, North Dakota, South Dakota, and Texas, as discussed in Section 2.1.

[197] Sub. for SB 69.

- ***Ensure utilities' financial health:*** Under this second criterion, LEI assessed how the different options impact the utility's ability to ensure its financial viability. Options that limit utilities' revenue or add financial penalties tied to performance could impact the utilities' cost of capital. The utilities' financial viability is reflected in their cost of capital, among other factors. Utilities that operate an efficient business in a stable regulatory environment have better access to capital, which could finance their expenditures. Lower levels of risks, whether real or perceived, factor into lower costs of capital and ultimately lower rates. In general, IOUs rely on capital markets for financing and thus are acutely sensitive to changes that impact their ability to meet their operational mandates (as defined by the PUC) *and* provide a predictable return to their investors.

- ***Minimize implementation costs:*** Under this criterion, the options were evaluated based on whether there are costs required in implementing the option. These costs could be for the utilities and/or the regulator and may include costs associated with conducting the necessary studies and stakeholder engagement. In addition, there may be additional expenditure on personnel and infrastructure, both initially and on an ongoing basis. Furthermore, an option, such as PBR or retail competition, may require the PUC to hire more staff (or external consultants), so it can ensure that utilities remain in compliance with their new responsibilities.

- ***Incentivize utility efficiency and performance:*** In order to meaningfully improve their efficiency and performance, utilities must be incentivized to make the most efficient choices in terms of capex and opex, so that the financial incentives for the utilities are aligned with customer interests.

6.1 Management of capital and operating expenditures

The current framework for management of capex and opex for Kansas electric utilities is a function of Kansas's regulatory environment. Utilities in Kansas are vertically integrated, which means that these utilities own generation, transmission, and distribution assets, and can earn a regulated return for both generation and the "wire" assets. In contrast, in states that have adopted liberalized markets, only the "wire" assets (transmission and distribution assets) are regulated; generation resources are typically unregulated, meaning that they must earn revenues in the wholesale markets. The implication is that private investors take on the financial risks associated with building generation assets in liberalized markets; if the asset becomes uneconomic, the investors will not be able to earn the expected return. In totally regulated states such as Kansas, electric consumers assume the risks since, once the regulator approves an investment, it is added to the rate base of the regulated utility, and the utility earns the approved return over the regulated depreciable life of the asset, provided it is used and useful. It is therefore up to the regulator, the KCC in the case of Kansas, to ensure the prudency of capital and operating expenditures.

The KCC staff reviews rate cases based on the statutory standard through traditional means. Such traditional means include reviewing large projects during "(1) pre-construction to determine the construction bid process (lowest reasonable cost) and the analysis for need (used and required to be used), (2) during construction to monitor costs, change orders, and record-keeping, and (3)

post-construction to determine how well the project was managed, whether there were cost overruns that were justified or unjustified, and determination of whether any prudence issues exist."[198]

In a regulated environment, several options allow the legislature and regulator to guide utility expenditures and, once guiding principles are established, ensure that the utilities enact state policies in a cost-effective manner. Notably, a state energy plan would outline state policy priorities and therefore provide high-level guidance for utility investment. With these legislative priorities established, the regulator has several tools to ensure cost-effective investments and operational expenses. For example, an IRP forces the utilities to forecast their future power needs and allows the regulator to review and approve the utility's planning.

Other regulatory mechanisms that would allow for improved management of capex and opex include periodically completing full, non-settled rate cases allowing for a discovery process and the setting of precedent on rate-setting mechanisms;[199] the deployment of a competitive procurement framework to leverage competition for the construction of new generation assets, as opposed to relying on the incumbent utility; deploying asset management strategies, which would increase insight into the state of grid systems and help reduce maintenance and capital costs; or adopting a totex approach to calculating utilities' revenue requirement.

Another option explored in this paper is the liberalization of the energy industry, deregulating the power generation sector, creating competition for the supply of power, and shifting some of the risks associated with large capital investments to private investors.

6.1.1 State energy plan

According to the National Association of State Energy Officials ("NASEO"), State Energy Directors "establish a strategy or framework to meet current and future energy needs in a cost-effective manner, enhance energy system reliability, expand economic opportunity, and address environmental quality." Furthermore, "[s]tate energy plans enable states to capitalize on existing energy resources, infrastructure, and human capital through targeted goals and directives to encourage economic development and […] set forward-thinking energy policies for the state. […] [A] state energy plan is a package of strategic goals with recommended policy and program actions to support those goals."[200]

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[198] KCC's response to LEI's data request dated October 25, 2019.

[199] For clarity, LEI is not recommending against settled rate cases. However, periodic non-settled rate cases are useful to enhance transparency and precedence setting for future rate cases.

[200] National Association of State Energy Officials. "*NASEO's State Energy Planning Guidelines*." 2018.

A state energy plan would include the following key components:

1. Targeted goals;
2. Directives; and
3. Forward-thinking policies.

Using this definition, it is apparent that Kansas does not currently have a state energy policy. This is demonstrated, for instance, by the reversion of the mandatory renewable portfolio standard to a voluntary standard and the continuation of energy efficiency programs during periods of low or no-load growth while there is excess generating capacity.[201]

According to NASEO, a state energy plan should feature four key characteristics to make it valuable: it should be comprehensive, adaptable, guiding, and strategic.

The development of the state energy plan should follow a well-designed process. The first step is to have the state energy plan initiated by a top-level state authority, which would guarantee that the required resources will be allocated to its development and ensure that the resulting plan would be seriously considered for implementation. The development of a state energy plan also requires data collection and public input. After developing the goals and specific actions required to reach them, the energy plan should be publicized, implemented and the progress should be monitored.

Key elements of a valuable state energy plan

- ***Comprehensive***: Takes into consideration a holistic perspective of the state's energy profile, including all energy resources and end-use sectors as well as input from key public and private stakeholders;
- ***Adaptable***: Projects future energy supply and demand and models the potential impacts of supply shifts, geopolitical risks and uncertainties, technological change, and other factors that affect short- and long-term energy needs;
- ***Guiding***: Provides a framework that allows state and business decision makers to make informed and educated judgments based on the predictability ensured by a defined and structured plan; and
- ***Strategic***: Offers a deliberate and vetted plan of action that lays out clear recommendations and actions that are set within measurable and achievable goals.

Source: NASEO State Energy Planning Guidelines

[201] For example, the Energy Efficiency Surcharge allows cost recovery of energy efficiency programs if it passes a cost-benefit analysis. According to KCC's Order for Docket 08-GIMX-442-GIV, the cost benefit analysis relies on the utility's own internal model, which is likely to resemble a marginal cost proxy plant used to meet incremental load. Note that LEI is not suggesting that renewable portfolio standards or energy efficiency programs are good or bad per se, but rather that they should be approached as part of a coordinated strategy.

Figure 103 illustrates the key features and characteristics of energy plans in states comparable to Kansas.

Figure 103. Summary of regional states' energy plans

State	Name of the State Energy Plan	Year published	Authoring body	Goal
Arkansas	APSC Sustainable Energy Resources (SER) Action Guide	2010	Arkansas Public Service Commission	Gaining a better understanding of sustainable resources and technologies, examine how emerging technology and innovative regulatory paradigms can help modernize the regulatory compact for utilities that promotes a more efficient use of energy while utilizing newer technologies
Colorado	Colorado State Energy Report 2014	2014	The Colorado Energy Office, the Colorado Department of Natural Resources, and the Colorado Department of Public Health & Environment	Provides the framework through which Colorado will continue to pursue its energy policy — one that responsibly grows Colorado's economy and is based on four values important to Coloradans: growing jobs and spurring innovation, protecting the environment, streamlining Government, encouraging collaboration
Iowa	Iowa Energy Plan	2016	Economic Development Authority and Department of Transportation	Development of an affordable, reliable and sustainable energy system that maximizes economic benefits for our state
Minnesota	Minnesota's 2025 Energy Action Plan	2016	Rocky Mountain Institute	Lays out a path forward for Minnesota to help advance a clean, reliable, resilient, and affordable energy system for Minnesota
Missouri	Comprehensive State Energy Plan	2015	Department of Economic Development, Division of Energy	Develop a comprehensive energy plan to balance the need for low-cost, reliable energy while being responsible stewards of the environment
Nebraska	Nebraska Energy Plan	2011	State Energy Office (Merged to become Department of Environment and Energy)	Ensure access to affordable and reliable energy for Nebraskans to use responsibly
North Dakota	Empower North Dakota Comprehensive State Energy Plan	2008, updated in 2016	Department of Commerce	The policy of this state to stimulate the development of renewable and traditional fossil-based energy within the state with the goal of providing secure, diverse, sustainable, and competitive energy supplies that can be produced and secured within the state to assist the nation in reducing its dependence on foreign energy sources
Oklahoma	First Energy Plan	2011	Governor's office	Fostering economic development, transitioning transportation fuels, optimizing the existing energy system, and positioning Oklahoma for the future by pragmatically leveraging Oklahoma resources
South Dakota	N/A	N/A	N/A	N/A
Texas	State Energy Plan 2008	2008	Governor's Competitive Council	Proposes a road map to guide Texas toward a future with a reliable energy supply that is balanced and competitively priced

Sources: Arkansas Public Service Commission, Colorado Energy Office, Colorado Department of Natural Resources, Colorado Department of Public Health & Environment, Iowa Economic Development Authority, Iowa Department of Transportation, Rocky Mountain Institute, Missouri Department of Economic Development, Nebraska Department of Environment and Energy, North Dakota Department of Commerce, Oklahoma First Energy Plan, Texas Governor's Competitive Council.

Developing a state energy plan can help Kansas determine what its energy goals are, how to achieve them, and at what cost. Although a state energy plan would not directly affect past capex and opex spending or result in an immediate reduction in rates, it would help to ensure that future capex and opex spending is targeted towards projects that help further state energy policy. The state policy objectives should extend to all entities serving electric customers in the state, including utilities, munis, and co-ops.

6.1.2 Integrated Resource Plan

According to the National Association of Regulatory Utility Commissioners ("NARUC"),[202] IRPs were a "state response to [the 1970s energy crisis to] minimize the total societal cost of electricity in production." IRPs differ by state and utility, but they typically feature a long-term planning horizon (15 to 20 years), are updated every two to five years and include a load forecast with detailed modeling, a resource assessment and acquisition plan, transmission network requirements, and a financial forecast (e.g., cost required to meet demand and average system rates).

Currently, under KCC Docket 13-GIME-256-CPL, Westar Energy, Kansas City Power & Light Company, Empire District Electric Company, Kansas Power Pool, Kansas Municipal Energy Agency, Kansas Electric Power Cooperative Inc., Midwest Energy, Sunflower Electric Power Corporation, MidKansas Electric Company, and Kansas City Board of Public Utilities are all required to file annual generation capacity needs, system peak capacity needs, and renewable generation needs (now voluntary in Kansas) to the KCC.

One purpose of this filing is to ensure that utilities comply with SPP requirements. Specifically, "SPP requires its members to annually submit ten-year capacity and load projections to show how the utility will meet its ongoing system [obligations, …] including the 12% reserve margin requirement outlined in the Criteria."[203]

However, these filings do not include the level of detail that would be included in an IRP. Currently, most utilities in Kansas are not required to go through a regular IRP process except for selected utilities, such as the BPU. According to BPU, it "is required by law to file an IRP with Western Area Power Administration, an agency of the US Department of Energy, and update the plan every five years. As part of this requirement, BPU must also submit annual progress reports and the status of its IRP."[204]

According to Advanced Energy Economy, a national association focused on energy products, services, and policies, "33 states, either by state statute or regulation, require utilities to file publicly available IRPs or their equivalent with their [regulator]."[205]

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[202] NARUC. "Integrated Resource Planning the Basics and Beyond" October 2013

[203] KCC. "Electric Supply and Demand Annual Report 2019"

[204] BPU. "BPU Takes Public Comment on 2019 Integrated Resource Plan." July 24, 2019. <https://www.bpu.com/about/medianewsreleases/bpu-takes-public-comment-on-2019-integrated-resource-plan.aspx>

[205] Advanced Energy Economy. "Understanding IRPs: How Utilities Plan for the Future." August 11, 2015. <https://blog.aee.net/understanding-irps-how-utilities-plan-for-the-future>

Figure 104. States requiring utilities to file an IRP with their regulator

Source: Advanced Energy Economy

According to BPU's 2019 Electric IRP, the IRP is "a long-term strategy plan used to guide resource acquisition, conservation, and demand-side management (DSM) decisions. The IRP process combines technical analysis and public participation to ensure low cost reliable electric supply." Furthermore, it provides a clear summary of the goals and requirements of an IRP as "an on-going and evolutionary process calling for re-analysis of utility system plans as conditions, prices, costs, technologies, and power requirements change. The integrated resource planning process anticipates the future and considers the many uncertainties a utility faces. An objective of integrated resource planning is to find the lowest cost solution that supplies customers the amount and quality of electric service desired while at the same time supporting the utility's long-term financial health."[206]

Typically, IRPs are filed by a utility or a Load Serving Entity ("LSE"). However, certain states have statewide IRPs. For example, California Senate Bill 350 requires the California Public Utilities Commission ("CPUC") to "adopt a process for integrated resource planning to ensure that load-serving entities meet targets to be established by the California Air Resources Board, reflecting the electricity sector's contribution to achieving economy-wide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030."[207] This resulted in the CPUC and

[206] BPU. *Integrated Resource Plan 2019.* October 2019.

[207] CPUC. Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. 2/19/2019

the LSEs developing an "umbrella" planning proceeding that involves a two-year cycle. First, the CPUC develops a set of common assumptions that all LSEs must use to develop their individual IRPs. Then, the LSEs create individual IRPs, which must include one scenario based on the generic long-term assumptions defined by the CPUC.

CPUC's Long-Term Procurement Plan Assumptions

- Detailed planning assumptions for first 10 years and more generic long-term assumptions for second 10-years
- Nine scenarios that help agencies test for overall impact on emissions, costs, and reliability
- Demand-side and supply-side planning assumptions
- Load forecast with energy efficiency impact and demand respond impact
- Transmission and distribution line losses
- Calculation of resource retirement dates
- Assumption on contribution of imported and exported resources
- Renewable resource portfolio assumptions
- Define which scenario is considered the Default Scenario

Source: CPUC. "Assigned Commissioner's ruling adopting assumptions and scenarios for use in the California Independent System Operator's 2016-17 transmission planning process and future commission proceedings" 17 May 2016

Other regional states also have detailed requirements on what types of information and analyses should be included in IRPs. For example, Missouri requires utilities to file IRPs once every three years that include load analysis, supply-side analysis, demand-side analysis, integrated analysis, and risk analysis with very specific modeling requirements. The supply-side analysis should include identification of new technologies and ranking of options based on annualized utility and probable environmental costs. The risk analysis should include specific methods of decision analysis (probability and scenarios).[208]

The main differences between a state-wide IRP requirement and the current rate-case filing process in Kansas are:

- **Timing and filing cycle** – Rate case proceedings force the regulator into a reactive role since rate cases are filed in specific circumstances, for instance, when the life-cycle of the previous rate case has run its course; if consumers file a complaint; or following certain events such as a merger or change of control of a utility. Therefore, different utilities may be filing rate cases that are years apart, leading to differences in cost estimates, demand forecasts, renewable targets or other assumptions that would impact the rate cases. A

[208] Missouri Public Service Commission. "IRP Rules in Missouri, Past & Present". May 20, 2005.

mandatory IRP process operating on a fixed cycle would require all utilities to analyze their needs at a synchronized timeframe and frequency and allow the regulator to review and approve the utilities' planned investments.

- **Common assumptions –** IRPs need not be rate cases and can be used to inform subsequent rate cases. A statewide IRP requirement would allow utilities to develop their resource planning based on a common set of assumptions. This common set of assumptions can include a wider range of scenarios and complex analyses on resource adequacy, transmission, and other requirements that relatively smaller utilities would not necessarily be able to develop on their own.

- **Consistent methodology –** A statewide IRP would also require utilities to use a common methodology to establish their development plan. For example, the evaluation method that constitutes a "least-cost option" would be standardized across utilities. IRPs filed by different utilities would, therefore, be comparable.

- **Policy objectives –** State policy objectives should be taken into account when developing a resource plan for reliable electric supply at least cost. Examples of such goals include economic development targets, energy efficiency deployment, or, more recently, energy storage requirements and generation flexibility to facilitate renewable integration. Without a statewide IRP mandate, it would be harder for regulators to assess the progress of utilities with respect to state energy goals.

To implement an IRP process in Kansas, the following questions would have to be answered:

- whether the IRP will be undertaken on a statewide basis or by individual LSEs / utilities;
- who will perform the modeling, studies, and analyses to determine resource needs;
- how the authorization (and procurement process) will be structured;
- how to measure LSE / utility compliance with IRP requirements, and on what timeframe;
- whether an enforcement regime is necessary, and if so, how to structure it;
- what should be the required content of the IRPs; and
- what will be the frequency and timing for IRP updates.

In addition, a statewide IRP process "obviates the need for the Commission to conduct after-the-fact reasonableness reviews for the resulting utility procurement transactions that are in compliance with the upfront standards established in the approved procurement plans."[209] This is similar to the pre-approval process that the KCC has undertaken in previous rate cases. Standardizing this pre-approval process though an IRP process can help reduce regulatory

[209] Ibid

burden in future rate cases, especially when common assumptions and methodologies are used in the analysis process.

The cost of developing IRPs depends on the level of detail and scope required in the IRP, such as the number of scenarios modeled, the type of technologies considered, and the timeframe of the planning period. The process for developing the IRP also affects its costs: are there multiple rounds of stakeholder feedback? Will there be public engagement sessions? An IRP would also help reduce other regulatory costs during rate cases, especially when a state-wide IRP could be used as the starting point for multiple regulated utilities' rate cases, resulting in a net saving in regulatory costs.

6.1.3 Methodical approach in rate case review and analysis

Kansas has a history of settlement-based rate cases. Based on LEI's discussion with stakeholders, one of the key drawbacks of having almost all rate cases settled is the lack of precedence in rate-setting mechanism. In other words, when reviewing rate cases, it is harder for the regulator to utilize review standards or methodologies developed in previous rate cases since those standards or methodologies were not explicitly approved in previous rate cases. As such, the methodology used to review each rate case may not be consistent.

Managing capex and opex to achieve and sustain regionally competitive retail electricity rates requires a consistent analytical approach in reviewing rate cases, especially when issues being considered are complex, and uncertainty surrounding the forecasts used is high. The components of a methodical rate case review could include the following:

- Assumptions used in forecasting demand and fuel prices are consistent. Ideally, if there is an IRP, the utilities are required to use the assumptions and forecasts presented in the IRP unless there is a material change in objective economic or supply and demand conditions;
- Specific requirements in rate case submissions, such as presenting non-transmission alternatives and sensitivity analysis related to demand, fuel prices, or carbon price forecasts; or
- The cost-benefit analysis conducted during rate rider cases should take into account factors such as the current oversupply and declining demand environment.

If utilities and stakeholders can demonstrate consistency in their analysis and review standard for settled rate cases, and settled rated cases can demonstrate consistency with IRPs, then settlements could continue to be a viable method for Kansas to set electric tariffs.

Using consistent forecast assumptions

As discussed earlier, some states require utilities to file IRPs based on a set of common assumptions and forecasts. These forecast assumptions can then be used in rate cases. However,

absent an IRP requirement, standard forecasting methodologies, and consistent development of input assumptions should be required when utilities develop their rate cases.

For example, the KCC could require all utilities to develop their load growth forecast using population forecasts and economic forecasts from a specific source (e.g., US Census Bureau and Federal Reserve Bank of St. Louis) as of a certain date as long as the rate case is filed before a cutoff date. This assumption should not be an item to be negotiated unless there is a strong reason (such as a recent forecast materially deviating from realized figures).

Similarly, on the supply side, KCC can require utilities to develop their generation and other capital cost assumptions using national sources with regional adjustments (e.g., using capital cost assumptions from the Energy Information Administration), unless they can provide substantial evidence of alternative costs, such as actual engineering-procurement-construction ("EPC") quotes.

By requiring utilities to adopt certain common input assumptions, the time and cost required to process a rate case could be reduced.

Requirements on specific analyses in rate cases

The history of rate cases being settled means there is not many standardized analytical methods being used to determine the merits of specific arguments presented during rate cases.

For example, some electricity consumers have commented that financial losses from generation units indicate that utilities do not offer these resources economically in the SPP markets. Since generation and energy costs are passed through to consumers via the Energy Cost Adjustment clause, there are no incentives for utilities to ensure their resources are dispatched when it is economical to do so. It would be out of the scope of this paper to determine whether utilities that own generating assets have systemically dispatched their units uneconomically, however, this is one area where regulators could perform oversight. For instance, utilities could be required to report how the resources are offered in the SPP markets, and their process and past operations could be audited by an external entity. If generation assets are found to have purposefully been dispatched uneconomically (for instance following self-commitment in the markets), the losses incurred could be disallowed in rate case proceedings.

Other comments received by LEI from stakeholders concerned the number of line-item surcharges on their electricity bill. For instance, in some cases, line-item surcharges represented over 50% of a utility's electricity bill. While some of the surcharges are predetermined and should not be retrospectively removed (e.g., the Environmental Cost Recovery Rider), certain surcharges are driven by ongoing programs and could be reviewed to ensure the benefits to consumers outweigh the costs.

6.1.4 Competitive procurement framework

Utilities can fulfill their resource adequacy requirements via several means, such as owning their generation assets, procuring supply through long-term or short-term contracts, or participating in organized wholesale markets. In Kansas, utilities directly own a large portion of the generation

capacity required to meet the load.[210] For future power needs, however, it could be beneficial to consumers to leverage competition in order to obtain the lowest cost for future generation assets, while still remaining in a regulated environment. Indeed, the establishment of a competitive procurement framework would allow outside entities to compete for the opportunities to construct generation assets meeting the utilities' needs, and the winning entity would obtain a long-term contract with the utility. The key design factor of such a procurement process is that the incumbent utility should either not be allowed to participate in its own tenders, or if allowed to participate, there should be strict rules in place to prevent the utility from favoring itself:

- the group responsible for the design and evaluation of the tender should be separated from the group that prepares and submits the utility's offer. In other words, there should be a "functional separation" between those groups;
- the team that prepares the utility's submission should not have access to any privileged information that is not also available to other participants;
- the evaluation of all submissions to the tender should be overseen by an independent evaluator; and
- in some cases, the utility's submission should only be considered as the proposal of last resort should no other entity's submission be able to meet the tender requirements.

Hawaii's competitive procurement process framework

Except for the island of Kauai, which is served by a co-op, all other islands in the State of Hawaii are served by the IOU Hawaiian Electric Industries ("HEI"). For the procurement of new generation assets, the Hawaii PUC has instituted a competitive procurement framework with the following key attributes:

- **Design of an RFP**, which identifies any unique system requirements, resource attributes and criteria for the evaluation. The RFP includes bidding guidelines and requirements, evaluation, and selection criteria, as well as risk factors. It also includes proposed forms of PPAs and other contracts, with specific terms or stipulations addressed.
- **Issuance of the RFP**, which is provided with adequate notice and through utility encouragement of participation from bidders. It also includes a formalized process to answer any of the bidders' questions.
- **Development and submission of proposals by bidders.** The utility self-bid must be submitted one day in advance of the deadline specified in the RFP.

[210] Based on KCC's Electric Supply and Demand Annual Report 2019, Westar has direct ownership of 6,298 MW of generation, while KCP&L has 4,860 MW (including units located in Missouri). At the same time, Westar only has 5,855 MW of projected system peak responsibility in 2021, while KCP&L only has 1,840 MW (excluding demand in Missouri).

- **A "multi-stage evaluation process"** to reduce bids down to a shortlist, which is determined through receipt, completeness, initial evaluation of price and non-price criteria, a detailed evaluation of portfolio development, and final selection of the shortlist.
- **Contract negotiations.** The utility can negotiate amongst the shortlisted bidders. Some examples of items that could be negotiated include project operating characteristics and fuel supply arrangements.
- **Commission approval.** The PUC ensures that the process was fair, consistent with the Integrated Resource Plan, represents best practices, and aligns with the public interest. The PUC can review, approve, or reject the contracts that emerge from this process.

Source: Hawaii PUC Decision and Order No. 22588 of Docket No. 03-0372

6.1.5 Using a totex framework in PBR

The total expenditure ("totex") framework refers to an approach that can be implemented as part of a performance-based ratemaking mechanism. Under a totex approach, instead of setting the revenue requirement of a regulated utility using its capex and opex forecasts, the rate-setting mechanism no longer distinguishes between the two. Instead, the regulator allows the regulated utility to earn a return on an expected efficient totex.

The main reason for allowing utilities to earn a return on totex, as opposed to the traditional rate base calculated from capex, is to address the potential issue of capex bias. This refers to the intrinsic bias toward capex in traditional ratemaking; there are several potential sources of capex bias:

- Utilities are not allowed to earn a return on opex in traditional ratemaking mechanisms, whereas capex helps them grow their rate base and increase the returns for their investors – this is acknowledged by utilities, which identify capex as "platform for growth"[211];
- Building up the regulated asset base results in higher financial stability for the utility's investors;
- Different treatment of opex over/underspending than capex over/underspending in the incentive mechanism of the performance-based regulation; and
- Other cultural, ownership, or control preferences of a utility.

The totex approach aims to create a regulatory construct whereby the regulated utility is rewarded for implementing the most efficient solution, irrespective of whether it is opex or capex. For example, more frequent tree trimming can reduce the need for investments in distribution infrastructure. However, in a regulatory construct with the potential for capex bias, utilities could be incentivized to reinforce the distribution grid through capex. The totex approach, combined with performance-based regulation, is designed to focus on the desired outcome – for instance, system reliability and other objectives (e.g., safety, customer service, billing accuracy, distributed

[211] Westar Energy, Inc. Form 8-k. August 22, 2016. <http://www.evergyinc.com/node/33591/html>

energy resource connections) set by the regulator. As long as the utilities are meeting expectations with respect to the target, they are rewarded irrespective of the nature of their spending.

Treatment of cloud computing expenses

The development of cloud computing services and the adoption of such services by utilities have blurred the line between capex and opex. Traditionally, utilities invest in IT infrastructure (computer servers, network infrastructure, custom software) through capex which is included in the rate base. Introduction of cloud computing services allows utilities to instead subscribe to IT services on a periodic basis so that these expenses, under traditional regulatory accounting, are considered as opex. Such treatment could discourage utilities from opting for cloud computing as there is no return on investment for opex.

This view is also shared by the New York Public Service Commission ("NYPSC"). In 2016, in a case related to ratemaking and the utility revenue model, the NYPSC stated that "[n]umerous IT applications will need to be developed and implemented. Rather than developing their own software, many businesses find it more efficient to lease software services over extended periods, typically three to five years. To the extent that these leases are prepaid, the unamortized balance of the prepayment can be included in rate base and earn a return. As utilities evaluate whether to purchase or lease these applications, their ability to earn a return on a portion of the lease investment should help to eliminate any capital bias that could affect that decision."

The totex approach removes the distinction between opex and capex, allowing utilities to choose the most efficient solution rather than the solution that allows them to grow their rate base.

Source: State of New York Public Service Commission, Docket 14-M-0101

Figure 105. High-level illustration of building block vs. totex approach

There are different flavors of totex when determining the annual revenue requirement of a regulated utility. Below are two high-level examples illustrating how a totex approach has been implemented in the UK and the Netherlands.

United Kingdom

The current iteration of the UK's performance-based regulation regime for distribution companies is called RIIO, which stands for "Revenue = Incentives + Innovation + Outputs." Under the RIIO framework, there is no concept of capex and opex when determining the revenue requirement of the regulated utility. Instead, the totex would be split into "fast money" and "slow money." "Fast money" would be recovered within the regulatory period, while the "slow money" (instead of capex) is capitalized into the regulated asset base and recovered over a longer time period (i.e., over multiple regulatory periods).

Totex includes *"all economical and efficiently incurred expenditure relating to a [utility's] regulated [transmission or distribution] business,"* including non-operational capex and business support

costs and excluding pension deficit repair payments, statutory/regulatory depreciation, and amortization, etc.[212]

The ratio between fast and slow money is calculated based on studies of historical capex, and opex split at the beginning of RIIO (and differs for each utility) and is fixed for the entirety of the regulatory period. The ratio can change at the beginning of new regulatory periods based on financing parameters or other factors presented by the utilities. Under RIIO, increasing capex and reducing opex would not result in an inflated regulated asset base, thus effectively removing the utilities' incentive to substitute opex with capex.

The Netherlands

In the Netherlands, the regulated move towards a totex approach uses a concept called the consumption of capital. To implement this concept, each distribution company's initial regulated asset base costs are calculated and standardized through an extensive accounting and regulatory review exercise. Then, the output of each distribution company is measured,[213] and a ratio called Composite Output per unit of Total Cost for the industry is calculated for the industry as a whole. This "per output unit cost" does not distinguish between capex and opex. All distribution companies are allowed to expense the same amount of Composite Output per unit of Total Cost; therefore, companies that manage to provide a higher level of output per unit of Total Cost would earn a higher return than the industry average.

A totex approach, through any of its possible implementation mechanisms, can help Kansas improve the management of capex and opex by Kansas utilities. Reducing the capex bias would encourage utilities to focus on efficiency instead of building rate base, especially when there are competing options between capex and opex that can deliver similar levels of outputs.

Before implementing a totex approach, however, several steps need to be performed:

- Conduct a more detailed study to determine if there is actually capex bias by the utilities;
- Develop objectives for the utilities. These can be defined as part of a state energy plan, where the state policy objectives are converted into measurable metrics; and
- Perform a quantitative study on the appropriate ratio of fast and slow money applicable to Kansas, or similarly perform a benchmarking study to calculate the industry average Output per unit of Total Cost.

[212] Ofgem. "Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control." 2013.

[213] Here, output can refer to any measure, or combination of measures, or a utility's activity. For a distribution utility, this can correspond to total energy sales by volume, for example.

A totex approach is a relatively new concept in utility regulation, and there are potential risks involved in its implementation. For example, determining the split between fast and slow money could be contentious. If the capitalization rate (i.e., the amount of totex capitalized as regulated rate base) is set too low, the utilities may not be able to finance their long-term investments. However, if the capitalization rate is set too high while the approved WACC is higher than the true WACC of the utility, the utilities would have continued incentive to increase overall totex. Therefore, totex itself cannot completely solve the problem of over-investment by utilities without other forms of expenditure scrutiny or benchmarking

6.1.6 Incentivize utilities to deploy asset management strategies

Recent advancement in technology, such as 4G and upcoming 5G cellular communication networks, the digitalization of the grid, exponential growth in computational power (e.g., artificial intelligence, digital clone of physical assets), and innovation in robotics and sensors (e.g., drones, higher resolution cameras), has allowed utilities to have a much more detailed awareness of the state of their system. This increased awareness generates large amounts of data for processing in faster computers with better algorithms, giving utilities a better understanding of the performance and condition of their assets. These advancements have resulted in the need for new management strategies for utilities.

Some examples of such a new management strategy include:

- reducing opex and increasing reliability by deploying on-demand preventive maintenance (instead of regularly scheduled maintenance), since close monitoring of asset condition and data analysis allows utilities to better understand failure modes and the need for preventive maintenance; and

- lowering capex and increasing reliability by increasing asset life / deferring new capex through improved maintenance procedures.

According to one study, analytics and sensors could help reduce O&M costs in transmission by 40% and in distribution by 20% over an 8-year period, while deploying asset management strategies for distribution substations could lead to 24% savings in O&M costs.[214]

However, implementing such asset management strategies can be costly, especially when it involves the deployment of new sensors and information technology across the grid. Utilities may not be incentivized to deploy such strategies because:

[214] Tenaga Nasional Berhad. Grid of the Future study. 2016. The cost/benefit assessment could be different in Kansas, depending on the existing transmission infrastructure and cost of deploying such asset management strategies.

- they do not directly benefit from a reduction in opex;
- regulatory approval for this type of capex is not guaranteed, absent some form of the regulatory or legislative mandate for such projects; and
- conservative culture in utilities leading to a preference for proven technologies instead of innovative ones.

To incentivize utilities to implement advanced asset management strategies, the Kansas regulatory framework could be modified to allow efficiency carryover mechanisms or allow a higher rate of return for expenditures related to such strategies if independent studies can justify long-term savings to consumers.

Efficiency carryover mechanisms

Efficiency carryover mechanisms or efficiency-benefit sharing schemes ("EBSS") are mechanisms used by regulators to incentivize regulated entities to improve their efficiency. These EBSS allows regulated utilities to retain a portion of the savings achieved relative to the approved level of expense over a specific period of time.

For example, assuming an EBSS with a 50% opex carryover factor, a regulated utility managing to deliver the target level of service during a regulatory period while spending $20 million less than the approved opex level would be allowed to keep those savings. However, for the following regulatory period, the approved opex level would be $10 million lower since the regulated utility gets to keep 50% of the efficiency savings it achieved, while ratepayers also benefit from lower opex.

There are multiple configurations of an EBSS. For instance, there can be negative savings sharing (i.e. utilities overspending); the carryover factor can be asymmetric between over- and under-spending; or there can be a "band" where savings above or below a certain threshold are not included into the sharing mechanism (to avoid extreme results and to reduce non-material calculations).

Under a traditional cost-of-service ratemaking regime, regulated utilities may not have sufficient incentives to lower their opex since these costs are passed through to consumers. With an EBSS, regulated utilities may be able to earn a higher return by taking risk and investing into efficiency enhancing projects.

EBSS have been implemented in multiple states and also abroad, such as in Hawaii, Massachusetts, Canada, and Australia.

It should be noted that such incentives could be duplicative of PBR mechanisms. Therefore, KCC should take a holistic view on whether various incentives are coherent and avoid double counting of efficiency savings (and rewards) to the utilities.

6.1.7 Deregulation of power generation

As discussed earlier in this section, one key driver of the rate increases in Kansas in the past decade is capex for environmental control equipment for existing IOU-owned coal plants. The Rate Study conducted by KCC staff found that 33% of KCP&L's rate increase from 2007 to 2018 was driven by environmental investments, compared to 34% for Westar.[215]

Also, the material drop in natural gas prices over that period has resulted in coal-fired generation becoming more expensive than gas-fired generation most of the time on a short-run marginal cost basis (according to the Rate Study, there has been "loss of profit from wholesale energy sales from excess coal production"[216]). Therefore, the utilization rate of coal plants has dropped, but consumers are still required to pay for the capital cost of the units that are already incorporated into the utilities' rate base.[217]

Furthermore, some units developed by the utilities (such as Iatan 2 and Emporia Energy Center)[218] to meet demand growth and forecasted reliability needs were not utilized when the expected demand growth did not materialize. These investments are nevertheless incorporated into the regulated asset base of utilities, which are then allowed to earn a return on and return of capital from electric ratepayers.

It is outside the scope of this analysis to revisit the merits of past investment decisions. However, the question to ask is whether customers should be taking on risks related to large generation investments, or whether such risks should be passed on to investors, and whether such shifting of the risks could result in sustainable and regionally competitive retail rates for future years.

In the early 2000s, Kansas did have more regionally competitive rates thanks in part to a higher share of coal-fired generation as compared to the rest of the US and the region. However, it is also this difference in generation fuel mix that has resulted in large increases in electricity rates since 2008 due to state and federally mandated environmental investments. Figure 106 illustrates the change in the relative ranking of electricity rates between regional states from 2000 to 2018 and the percentage of coal-fired generation in the state during this period. Except for Iowa and Missouri, states with a below-average share of coal-fired generation have featured relatively lower rates than other regional states from 2000 to 2018 (most notably Texas, but also South Dakota and Arkansas), while electricity rates in states featuring above-average coal-fired generation have become relatively more expensive (North Dakota, Colorado, and Kansas).

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[215] KCC. "Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018". December 2018.

[216] Ibid, P. 7.

[217] Ibid, P. 26. "For electric utilities doing business in non-restructured jurisdictions, rate base includes the net value of its investments in generation, transmission and distribution infrastructure. [Note: Kansas has not restructured.]"

[218] Ibid, P. 3.

Figure 106. Change in relative average electricity rates among regional states from 2000 to 2018

Source: Fuel mix from EIA-906, EIA-920, and EIA-923, average prices from EIA-861, LEI analysis

There is, of course, a possibility that coal-fired generation would have resulted in low-cost energy for a very long period of time. For example, if low-cost technology to improve the environmental impact of coal was developed, then the capex required for environmental investment would have been lower; or if natural gas prices did not fall dramatically, then coal-fired generation may have remained cheaper than a gas-fired generation. But even if utility decision-makers have exceptional insight into future generation cost trends (including fuel costs and environmental compliance costs), they would not necessarily have an incentive to develop the long-term least-cost option as long as they could prove that a substantial capex investment would be prudent in meeting forecasted demand.[219] Ultimately, the risk associated with large regulated investments is largely borne by consumers while investors are allowed to earn their approved return on the investment.

The asymmetry of risk and return can be partially resolved by shifting the risk onto the investors, which means deregulating some parts of the industry. For example, deregulation of the power supply sector has led many states to participate in competitive wholesale energy markets where generation assets are not part of the utilities' regulated asset base but instead operated by independent power producers participating in organized wholesale markets.

Kansas already has access to a wholesale energy market – IPPs already exist, and utilities are already participants in the SPP imbalance market.[1] Therefore, the key steps needed to move towards a fully unbundled wholesale energy market would require all regulated utilities to divest their generating assets. To ensure resource adequacy, Kansas utilities would participate in SPP's Resource Adequacy process, which procures capacity through a centralized market.

However, directly moving from an unrestructured market to a fully liberalized wholesale energy market would be a significant shock to the Kansas electricity industry. Furthermore, in an environment with declining demand, a fully liberalized wholesale energy market may not be attractive to investors to develop new generation assets, though there may be less need for such assets. Therefore, at this current stage, LEI does not recommend that Kansas immediately move towards full liberalization of the wholesale energy market.

6.2 Performance-based regulation

PBR, also known as incentive ratemaking mechanism, is a form of utility regulation that strengthens the financial incentives to lower rates and costs or improves non-price performance. It allows the adjustment of utility revenues based on performance. PBR is normally adopted to correct the most common foundational problems observed in COS regulation, such as:

[219] More specifically, regulated utilities' investments are presumed to be prudent. The burden rests with the regulator to determine that an investment is imprudent. Given the uncertainty in technological trends, it can be difficult for the regulator to provide evidence that the utility acted imprudently when choosing a currently low-cost generation technology to meet forecasted demand growth.

(i) weaker incentives for cost-efficiency;

(ii) lack of incentives to encourage prudent and efficient capital investment (e.g., higher risks towards 'gold-plating' due to the information asymmetry between regulators and firms, whereby the regulator has limited ability to assess the reasonableness of proposed capital investment budgets); and

(iii) associated administrative process.

PBR aligns the incentives of the utility with those of the regulator and the consumers, unlike the typical capital-maximization objectives of a utility under the COS regulation. Therefore, in PBR, the focus shifts from cost accounting to productivity analysis.

Moreover, PBR allows the utility sufficient freedom to decide how to best optimize its resources, given the targets and objectives. Similarly, the regulator does not need to frequently review the detailed cost accounts and capital expenditures for each utility.

PBR also addresses concerns about the achievement of an "optimal price" in sectors where there are natural monopolies. PBR mimics competitive pressures, even in a monopoly environment. Theoretically, an "optimal price" based on the quality of service demanded at the lowest cost can still be achieved. Provided that the PBR has been strongly contextualized and well-developed, it allows utilities to make decisions regarding costs and inputs to maximize output (relative to a given level of inputs) and ensure the most efficient allocation of competing inputs.

PBR can include a variety of mechanisms that could be used in multiple ways and different combinations. PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime. Currently, Kansas does not deploy any of these PBR mechanisms.

Light PBR includes mechanisms — such as performance incentive mechanisms ("PIMs") and earnings sharing mechanisms ("ESMs") — where payments to the utilities are adjusted based on their level of performance. The "medium" form of the PBR mechanism includes the rate cap where either the price or the revenue is capped for the regulatory period. This helps promote efficiency as the mechanism tends to change the link between a utility's rates and its costs and improves efficiency. At the end of the continuum is outcomes-based PBR, which is the new generation of PBR, where the focus is on the outcomes rather than the inputs to the revenue requirements. Each of these mechanisms will be discussed in detail in the following subsections.

The "right" form of PBR depends on the needs and values of the particular jurisdiction—each may be appropriate depending on the circumstances. Generally, the choice of a light versus a comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be considered as "stepping stones" towards the comprehensive PBR mechanism. Implementing PBR is a gradual process that takes some time. Therefore, LEI believes that starting with the light mechanisms would be a more realistic approach for Kansas.

Figure 107. Continuum of PBR regulation from "light" to "comprehensive" key mechanisms

6.2.1 Performance Incentive Mechanisms

With PIMs, payments to utilities are adjusted upwards or downwards based on the utilities' level of performance. PIMs involve metrics, targets, and incentives used to examine, evaluate, and enhance a utility's performance over time by providing information on industry trends and opportunities.

PIMs must support the utilities' and the state's strategic goals and be achievable, realistic, and measurable. For instance, if the state's goals are "to have regionally competitive rates and reliable electric services," then its PIMs should include indices on cost control and reliability. PIMs should be attainable, and utilities and the regulator should work together to design challenging, yet realistic standards. Moreover, PIMs must also be consistent with customer needs or expectations and what they are paying for.

Utilities use different PIMs for different sectors of the value chain. For instance, performance is typically measured in terms of efficiency and availability in generation while frequency and duration of outages and customer service metrics are used in the wires sector. Aside from balancing cost efficiencies and reliability, other areas for performance measurement in the wires sector include metering, billing and collection, customer service, and employee safety. Furthermore, what customers want for PIMs is a way of developing them.

PIM targets are set either by examining historical performance, focusing on desired outcomes or through technical or statistical methods. Past performance should provide insights into what the utility can achieve. Another approach is a benchmarking analysis with peer groups.[220]

Figure 108. Sample jurisdictions that have implemented PIMs

	Consolidated Edison of New York	Central Maine Power	New Brunswick Power	San Diego Gas and Electric	Ontario
Term of Tariff Plan	2010-2013	2008 – 2014	2013 - present	1999-2002	2009-2011
Rewards, Penalties or Both	Penalties Only	Penalties only	Penalties Only	Both Rewards and Penalties	Nonfinancial measures
Explicit Formula (Yes/no)	Yes	Yes	No	Yes	No
Reliability Metrics	SAIFI, SAIDI, other reliability investment metrics	CAIDI, SAIFI	All mandatory NERC Standards	CAIDI, SAIFI, MAIFI	SAIFI, SAIDI, CAIDI
Service Quality Metrics	Customer complaints, customer satisfaction, call answer rates	Complaint ratio, calls answered (%), call center quality, meters read, new connections	No explicit service quality standards tracked and subject to fines from the Energy and Utilities Board	Customer satisfaction, call center response, all injury frequency rate	New connections, underground cable locations, telephone accessibility, appointments made, emergency and written responses
Max Penalty	$152 Million	$5 million	N/A	$14.5 million	N/A

Notes:
AIFI - Average Interruption Frequency Index calculates the average number of momentary interruptions that a customer would experience in a given period.
CAIDI - Customer Average Interruption Duration Index measures the total duration of an interruption for the average customer and can be calculated as a ratio of SAIDI and SAIFI, provided they are calculated over the same period.
SAIDI - System Average Interruption Duration Index measures the total duration of an interruption for the average customer in a given period, typically in hours or minutes per year.
SAIFI - System Average Interruption Frequency Index measures the average number of times that a system customer experiences an outage in a given period and is usually calculated on an annual basis

Sources: California Public Utilities Commission, Maine Public Utilities Commission, New Brunswick Energy and Utilities Board, New York State Public Service Commission, and Ontario Energy Board.

Setting the potential rewards and/or penalties is a balancing act. "Name and shame" (publicizing outcomes) is an option before implementing penalties. Rewards and penalties should be significant enough to incentivize the utilities to perform better. They should also be reflective of the actual cost to remedy performance shortfall. Generally, rewards and/or penalties under PIMs are based on deviations set in percentage terms or standard deviations from performance targets.

[220] This would help identify areas where opportunities for improvement exist. With a large-sized sample, overall industry patterns reveal trends in performance.

Lastly, in determining and setting PIM targets, there should be a balance between the utility's financial viability and customer expectations and willingness to pay.

Numerous markets have implemented PIMs. Most of these PIMs are focused on reliability and service quality metrics. Figure 108 shows an example of distribution performance incentives that are both financial and non-financial.

6.2.2 Earnings sharing mechanisms

An earnings sharing mechanism ("ESM") is another mechanism under PBR. ESMs are designed so that extraordinary earnings (or losses) are shared among the company and its customers rather than retained (or absorbed) entirely by the company if formulae-driven price adjustments result in a significant divergence between prices and costs.[221]

Generally, ESMs involve three elements, namely, (i) a target return on equity ROE, (ii) a deadband around the ROE in which no sharing takes place, and (iii) sharing of gains or losses, which are outside the deadband. The ROE is the regulator-approved return for the utility. The deadbands allow customers to participate in gains without requiring extensive regulator involvement. The sharing percentages are the level of sharing between the utility and customers.

Deadbands and sharing percentages can either be symmetrical or asymmetrical. Customers share both upside and downside risks equally under the symmetrical system while customers or the regulated utility are taking on a disproportionate portion of the risk under an asymmetrical system. Figure 109 shows an example of an ESM with a symmetrical deadband and sharing percentages.

However, there are also some drawbacks to ESMs. First, an ESM can complicate the administration of a PBR system. Second, the ESM reduces the efficiency incentives created by shifting to PBR if attached to a productivity factor target. Some argue that a successful PBR implementation does not require an ESM. Nevertheless, many believe that by allowing customers to share in benefits--which arguably would not occur in the absence of incentives--the overall political acceptability of a PBR plan may also be increased.[222]

Although ESMs are not a feature of all PBR regimes, they are commonly used across the US and are unusual outside North America. A sample of provisions of these ESMs across the US is shown in Figure 110.

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[221] Such mechanisms serve the same basic purpose—ensuring prices do not get too distorted or deviate too much from actual costs—as in the case of clawbacks within a traditional COS system. In the context of indexation formulae, a complement to the ESM is an exit ramp, which triggers an automatic end to the current formulae application period (and thereby initiates a COS rate review) if prices deviate too much from costs.

[222] For example, true ups under symmetric ESM mechanism can neutralize the perceived impact of rate increases in the rebasing or review stage.

Figure 109. Example of a symmetrical sharing

Figure 110. Selected jurisdictions and their ESM provisions

Company Name	US State	Term	Sharing Mechanism
Central Hudson Gas & Electric	New York	Jul 1, 2010-Jun 30, 2013	Actual regulatory earnings in excess of 10.50% and up to 11.00% will be shared equally between ratepayers and shareholders. Actual regulatory earnings in excess of 11.00% and up to 11.50% will be shared 80/20 (ratepayer/shareholder). Actual regulatory earnings in excess of 11.50% will be shared 90:10 (ratepayer/shareholder).
Narragansett Electric	Rhode Island	Feb 1, 2013-Jan 31, 2014	Earnings between 9,5% and 10.5% are shared 50:50 between the utility and its ratepayers, while earnings in excess of 10.5% return are shared 25:75.
NSTAR Electric	Massachusetts	2018-2022	Sharing of 75% shareholders, 25% ratepayers over a 200 basis-point bandwidth of ROE
San Diego Gas & Electric Co.	California	2009-2013	The sharing mechanism contains a symmetrical 50 basis points "inner dead band" and six sharing bands between 50 and 300 basis points above or below the authorized ROR. Shareholders receive 25 percent of the earnings above or below the authorized ROR in the first band, increasing by 10 percent in each subsequent band. Also, shareholders receive 100 percent of the earnings above or below 300 basis points of the authorized ROR.

Sources: State of New York Public Service Commission, Rhode Island Public Utilities Commission, Massachusetts Department of Public Utilities, California Public Utilities Commission

6.2.3 Rate caps

Unlike a rate freeze, rates under rate caps could change during the regulatory term, based on the approved formula. More specifically, a utility's rates are adjusted annually through an indexing formula that tracks the inflation rate, less an offset to reflect the improvements in productivity that the utility could expect to achieve during the regulatory period. Under a rate cap, the utility

is required to perform annual productivity improvements. Furthermore, with a rate cap, a utility's revenues are allowed to diverge from its costs during the regulatory period. The decoupling of costs and revenues incentivizes the utility to increase productivity and decrease costs.

Price caps and revenue caps are examples of rate caps. The critical difference between price and revenue cap regimes is related to what the PBR formula applies to – rates in the case of price cap regimes, and revenue requirements in the case of revenue cap regimes.

Under a **price cap**, which is also called price indexing or rate indexing, the regulator approves a formula that determines how fast rates can increase. The regulator sets an ***initial price,*** and the rates are adjusted for each year, taking changes in inflation and productivity into account. A price cap provides incentives for cost efficiency and an increase in sales. These incentives arise because the tariff is fixed for the regulatory period and would not vary with changes in electricity sales within the regulatory period. Another advantage of a price cap is that it provides greater rate predictability for customers.

A price cap regime is best suited for utilities in an environment with stable or increasing demand as it provides incentives for them to operate cost-effectively while meeting the growing demand.[223]

On the other hand, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, the ***revenue requirement*** in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, which considers changes in inflation and productivity.

Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

6.2.4 Outcomes-based PBR

At the comprehensive end of the PBR continuum is the outcomes-based PBR framework. Outcomes-based PBR focuses on the outputs or outcomes of the PBR plan, rather than activities, which is generally the emphasis of the traditional rate filing.

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[223] Under a price cap, the utilities' revenues could grow with new customers and growth in demand from existing ones. The additional revenue contributes to funding for the increased capital and operating costs of serving new customers and additional load. However, utilities operating under a price cap regime are also exposed to revenue risk associated with actual electricity sales varying from forecasts of electricity sales used to set the rates.

The utilities in an outcomes-based PBR are expected to achieve the outputs that are set during the PBR filing (or before the implementation of PBR). These outcomes could be grouped into different categories, such as reliability and availability, operational effectiveness, safety, public policy responsiveness, customer satisfaction, financial performance, and environment, to name a few.

A good example of a jurisdiction under the outcomes-based PBR is the UK's RIIO model, which stands for **R**evenue set to deliver strong **I**ncentives, **I**nnovation, and **O**utputs. Under the RIIO model, the transmission and distribution utilities in the UK are encouraged to "*play a full role in the delivery of a sustainable energy sector*[224] *and deliver value for money network services for existing and future consumers.*"[225]

This model requires utilities to submit robust business plans that demonstrate that they are proposing the best option in terms of meeting the goals of the RIIO model.[226] The business plans include data such as the utilities' forecasts for network replacement, and capacity additions, to name a few.

6.2.5 Other potential PBR parameters

Other jurisdictions use other PBR components alongside the mechanisms mentioned above. These other parameters – which add to the PBR formula - include treatment of (certain) capital expenditures and unforeseen events, length of the regulatory period, and triggers for an "exit" or "off-ramp." Along with the mechanisms discussed above, the PBR parameters are shown in Figure 111.

Determining the individual PBR components requires careful consideration. Components need to be viewed holistically. Therefore, in determining the appropriate parameters and their combinations, the choice of one parameter influences the others. For example, the productivity factor is not independent of the inflation factor because an inflation index using macroeconomic outcomes-based measures takes some level of productivity gains into account. Also, utilities would consider the regulatory term (length of term before next review) of PBR depending on how they perceive their abilities to perform under a PBR regime. For example, a well-performing utility may assume that a longer regulatory term under PBR would provide a more extended period for it to reap the "rewards" of cost gains, while utilities that are not confident about achieving their productivity target may view a shorter period as a lower risk proposition.

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[224] Ofgem defines sustainable energy sector as "an energy sector that meets the broad needs of existing and future consumers. This includes delivery of low carbon energy and other environmental objectives, delivery of secure, safe supplies and delivery of value for money including meeting the needs of vulnerable consumers," from the Handbook for Implementing the RIIO Model.

[225] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. P. 2.

[226] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. P. 48.

Figure 111. Key components to consider for a PBR formula

Components	Purpose
Going-in rates	Starting point of the PBR regulatory term. Rates usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period
Regulatory period	Scheduled time lag between two major reviews of the underlying components of the ratemaking regime
(I) - Inflation/ escalation factor	Annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year
(X) - Productivity factor / stretch factor	Annual adjustment to revenue or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or on external benchmark. May include a firm-specific target, or stretch factor
(K) - Capital expenditure or (G) Growth factor	Annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) needs or ex post approval of capex spending in the previous year
(Q) - Performance standards factor/ PIM	Contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality as well as reliability and quality of supply
(ESM) - Earnings sharing mechanism	Mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers
(Z) - Unforeseen events factor	Contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict
Regulatory review / Off-Ramp option	Mechanism allowing to trigger, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime
(F) - Flow-through factor	Contingent adjustment to revenue or rates reflecting certain cost event are automatically passed through to customers as they arise, without having to be approved by the regulator

6.2.6 Jurisdictions under PBR

PBR regimes exist in multiple jurisdictions throughout the world, as shown in Figure 112. In North America, the markets that have used or are currently using PBR include British Columbia, Alberta, Ontario, Oregon, California, New York, Maine, and Massachusetts. Hawaii, Illinois, Minnesota, Ohio, and Rhode Island are studying PBR as part of broader power sector transformation initiatives. PBR mechanisms used by markets in North America include PIMs, ESMs, and rate caps. Ontario has implemented an outcomes-based PBR, which they call customized PBR. Countries outside of North America, such as Australia, Malaysia, the

Philippines, and the UK utilize a more comprehensive combination of PBR mechanisms. A non-exhaustive list of jurisdictions that have implemented various forms of PBR is shown in the map below.

Figure 112. Examples of jurisdictions that have used, are currently using, or plan to move to PBR

6.2.7 Approach to designing rate cap

There are generally two approaches for rate-setting under a rate cap regime: (i) a total factor productivity ("TFP") based I-X approach; and (ii) the building blocks approach.

The TFP-based I-X approach was developed as a relatively simple mechanistic, yet empirically "rich" approach, to adjusting rate caps and providing incentives. The basic view that grounds most TFP-based applications of PBR models is that firms should be able to improve productivity consistent with measured long-term productivity improvements (historically) for the industry as a whole. In North America, the TFP-based approach to an I-X rate cap is among a number of PBR forms used.

The building blocks approach has been the cornerstone of PBR in Australia and the UK for over 20 years. First introduced in the early 1990s in the UK, the building blocks approach was

developed to derive the components of the price cap regime (RPI-X) that the regulator wanted to apply to newly privatized, monopoly industries, commencing with telecommunications, and then expanding to other network industries in gas and electricity.

Under this approach, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory control period (i.e., IR term). The forecast takes into account productivity improvements and targets and necessary capital investment. After this procedure, these total costs are added together ("built-up") to form an allowed revenue requirement for a utility based on estimates of the utility's expected capital and operating costs and return of and return on asset base.

The revenue requirement is then translated into a starting price (for the price or revenue cap) referred to as P_0, and an annual rate of change is estimated over the term of the PBR plan to adjust the price cap/revenue cap. The annual adjustment is referred to as I-X in Australia and RPI-X in the UK. The I factor is the inflation adjustment. Meanwhile, the estimated X factor reflects both the productivity target and the real price change required to support a utility's revenue requirement. This reference to an X factor can be confusing in the North American context because it is not solely a measure of productivity but reflects an aggregated view of efficiency trends across total costs and the need for efficient capital investment and (potentially) rate smoothing.

The revenue requirement that is forecasted for each year of the ratemaking period includes projections of efficient operating and capital expenditure. The efficient costs are assessed using historical performance metrics, yardstick benchmarks of unit costs, and often industry-wide benchmarks (including industry TFP studies). For example, regulators and utilities in Australia and the UK normally commission independent expert reports to assess the proposed expenditures that make up the forecast revenue requirements for each firm.

For Kansas, the I-X approach might be more appropriate than the building blocks approach given its mechanistic nature and the concerns of some stakeholders with regards to the PBR implementation. During LEI's meetings with stakeholders, there was a concern that implementation of PBR means "more work as utilities need to file on an annual basis."[227] An I-X approach would actually lessen the regulatory burden since utilities would not be required to file on a yearly basis.

[227] Meeting with the stakeholders on September 30, 2019, Topeka, Kansas.

Figure 113. Forms of PBR and approaches of setting rates in selected jurisdictions

Jurisdiction	Company	Service Covered	Duration	Form of PBR	Approach to setting rate
Alberta	ENMAX Power (835,000 customers)	Transmission & distribution	2007-2013	Price cap (distribution) Revenue cap (transmission	I-X
	Other Utilities	Distribution	2013-2017	Price cap	I-X
Australia	All distribution utilities (Victoria)	Distribution	2011-2015	Price cap	Building blocks
British Columbia	Fortis BC (111,500 customers)	Generation, transmission and distribution	2007-2008	Revenue cap (hybrid)	I-X
California	PacifiCorp (1.8 million customers)	Generation, transmission and distribution	1994-1996	Price cap	I-X
	San Diego Gas & Electric (3.4 million customers)	Distribution	1999-2001	Price cap	I-X
	So. Cal. Edison (14 million customers)	Transmission & Distribution	1997-2001	Price cap	I-X
Maine	Bangor Hydro Electric (153,000 customers)	Distribution	1998-2000	Price cap	I-X
	Central Maine Power (560,000 customers)	Distribution	2009-2014	Price cap	I-X
Ontario	Ontario electricity distribution utilities	Distribution	2010-2012	Price cap	I-X
Philippines	All transmission and distribution utilities	Transmission and distribution	2011-2015	Revenue cap (transmission) Price cap (distribution)	Building blocks
UK	All transmission and distribution utilities	Transmission and distribution	2013-2021 (transmission) 2010-2015 (distribution)	Revenue cap (transmission) Price cap (distribution)	Building blocks

Sources: AER, AUC, British Columbia Utilities Commission ("BCUC"), California Public Utilities Commission ("CPUC"), Maine Public Utilities Commission ("MPUC"), OEB, Philippine Energy Regulatory Commission ("ERC"), Ofgem

6.2.8 Implementation process for a PBR regime

Moving from a traditional COS regime to PBR can be an intimidating task for both the regulator and the utilities. It involves a significant amount of regulatory work and requires lengthy stakeholdering efforts to determine the appropriate PBR mechanism to implement and to allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation.

The first "formal" step in the PBR process is when the regulator (or sometimes, the utility) expresses its intent to implement a shift. In this step, the regulator is expected to explain the objectives clearly to all stakeholders as it embarks on the process. For example, in the case of

Hawaii, the Commission states that it was particularly interested in PBR mechanisms that result in "greater cost control and reduced rate volatility; efficient investment and allocation of resources regardless of classification as capital or operating expenses; fair distribution of risks between utilities and customers; and fulfillment of state policy goals." [228]

Experience and best practices dictate that the shift to a PBR mechanism requires establishing principles that should guide the stakeholders (particularly the utilities) in the development and implementation process. The principles will assist the regulator in the evaluation of and deliberation on the PBR proposals. Such principles should also guide the utilities in developing the most responsive and relevant proposals.

The move to PBR may also involve the hiring of an economic consultant to assist in determining the appropriate PBR approach, identifying the appropriate components for PBR such as incentives and magnitude of rewards or penalties for the performance standards, reviewing what data is currently available, or providing a study of historical and forecasts of inflation and productivity trends. It is also crucial that the regulators and stakeholders be regularly communicating and on the same level of understanding. Workshops and technical conferences are generally conducted to familiarize stakeholders with the proposed PBR approach and to solicit feedback.

Lastly, data availability is a critical element in the development of a PBR regime and will improve the functionality of PBR regulation over time. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. More "comprehensive" forms of PBR require collating and employing multi-period information and data samples covering multiple firms. Over time, availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools can improve the functionality of the PBR process, thereby, facilitating analysis and negotiations of parameters for PBR factors, as well as benchmarking actual productivity achieved against prior targets.

6.2.9 Impact of PBR regime implementation in other jurisdictions

PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[229] timely consumer benefits, lower administrative/regulatory costs, and greater compatibility with a rapidly changing industry.

PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[230] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver

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[228] Hawaii Public Utilities Commission. *Instituting a Proceeding to Investigate Performance-Based Regulation*, on April 18, 2018 Order No. 35411, April 18, 2018 at P. 5.

[229] Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29. November 27, 2003.

[230] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

exceptional service to their customers. With controlled costs, electricity prices in Kansas could be competitive with the region.

The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, BCUC noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[231]

Similarly, in the UK, Ofgem stated that the RPI-X regulatory framework has brought benefits to electricity customers over the last 20 years and has "*delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices.*"[232] In fact, "*since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization.*"[233] Ofgem also believed that the implementation of PBR *"has led to significant improvements in quality of service. Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."*[234]

With performance standards in place under a PBR regime, utilities' performance generally improves. In Ontario, Hydro One's performance in terms of service quality, customer satisfaction (e.g., billing accuracy), system reliability (e.g., the average number of times power to a customer was interrupted), and cost control (e.g., efficiency rating) improved over the years as shown in Figure 115. Hydro One is the largest transmission and distribution company in Ontario. Its distribution system is the largest in the province spanning approximately 75% of the province, serving 25% of customers.

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[231] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, P. 22.

[232] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

[233] Ibid.

[234] Ibid.

Figure 114. Hydro One's selected performance metrics (2013-2018)

Source: Ontario Energy Board. Utility Performance and Monitoring Scorecard (Accessed on December 4, 2019)

Also, PBR regimes are usually expected to lead to an overall reduction in the regulatory burden mainly because of a lower frequency of regulatory proceedings (when compared with markets under a COS approach) and a shift in focus to outcomes rather than quantifying inputs.[235] Reduced regulatory costs under PBR are a result of PBR's recognition of the information asymmetry between the regulator and the utility. Under COS, regulators spend a considerable amount of time and expense to bridge the information gap. In contrast, PBR does not try to rectify this information gap. Instead, under the PBR regime, the regulator does not need to know the costs for each O&M item but only needs to know the range of possible costs from which the regulator can approve a PBR plan that can produce maximum efficiency from the utility.[236] In addition, regulators benefit from PBR to the extent that it eases the demanding task of overseeing the activities of the utility. For the utilities, reduced regulatory micro-management allows them to respond more quickly to technological and competitive challenges. For customers, this may mean lower prices.

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[235] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[236] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 6.

Furthermore, a PBR regime does not necessarily lead to a reduction in capital investments. Indeed, capital additions of electric distribution and transmission utilities in Ontario have increased by an average of 2.3% per year from 2012 to 2018 (Figure 115).

Figure 115. Capital additions of transmission and distribution utilities in Ontario

Source: OEB. Yearbook of Electricity Distributors (2012 to 2018)

Finally, PBR can also serve both as a transitional mechanism to restructured and more competitive electricity markets and as a substitute for the actual competition.[237] According to Comnes, *"competition and restructuring often increase the complexity of allocating utility facility costs common to both competitive and non-competitive services. Thus, sticking to COS ratemaking in such an environment, perpetuates incentives for resource inefficiency and increases the cost of regulation… PBR is an effective transitional pricing mechanism for industry segments that are becoming more competitive over time. On balance, one may see the association of PBR with competition and restructuring as a way for regulators and the industry to (1) provide captive customers with reasonable rates without resorting to increasingly complex, contentious rate hearings and (2) increase the incentives for improved productivity in light of the possible future deregulation of utility prices."*[238]

6.2.10 Vertically integrated utilities under PBR

As discussed earlier, IOUs in Kansas are vertically integrated. There are several examples of vertically integrated utilities that have adopted the PBR approach in North America. From 1994 to 1996, PBR was applied to San Diego Gas and Electric's ("SDG&E") gas and electric businesses. On the electric side, SDG&E at the time was a vertically integrated generation, transmission, and distribution utility. SDG&E used a "revenue indexing" method where the utility's annual

[237] Sappington, David. *White Paper on Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan.* February 1, 2000. P. 11.

[238] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 8.

revenue requirement was adjusted using formulas for the revenue requirement associated with operating and maintenance expenses and determination of authorized capital expenditures. SDG&E's PBR originally allowed nuclear O&M expenses plus appropriate overheads. However, capital additions and nuclear O&M expenses were removed from the SDG&E PBR in 1996. In addition to this Base Rate PBR, SDG&E also had a generation and dispatch PBR, which was intended to provide incentives to make power purchases and operate power plants efficiently. SDG&E was rewarded or penalized based on the actual versus expected performance on targeted cost factors, including fossil unit forced outage and maintenance outage rates, economy energy costs, and firm contract costs. Because of PBR, SDG&E's operating costs and capex were lower than projected from 1994 to 1996.[239] Its O&M was reduced by $15-19 million below the authorized level, and this savings accounted for more than 50% of the utility's excess return in all three years.[240]

Central Maine Power ("CMP") is another example of a formerly vertically integrated utility that was under a form of PBR, referred to as the Alternative Rate Plan ("ARP"). CMP is an electric utility serving more than 500,000 customers in Maine. CMP's ARP was composed of a price cap (Gross Domestic Product Price Index – Productivity Factor) with an associated ESM.[241] The ARP was first implemented in 1995 and was in effect for five years. It covered all aspects of CMP's operations, including generation. CMP was still a vertically integrated utility at the time. As the utility was unbundled, the generation subsidiary became deregulated. CMP's distribution business remained under a form of PBR until 2016.

Another example is FortisBC, which is a vertically integrated utility in British Columbia. FortisBC was under a partial form of PBR from 1998 to 2001 and from 2004 to 2009.[242] The 1998-2001 PBR plan focused on pursuing operating and maintenance cost efficiencies, which included a limited capital incentive mechanism and a series of service quality standards that were tracked to confirm that service quality was being maintained throughout the term. The 2004-2009 PBR plan was based on the previous PBR plan and had additional features such as a 50/50 ESM between customers and shareholders, a longer term period, service quality standards that were more results-oriented, and an Efficiency Carry-over Mechanism, which was designed to encourage the company to continue to pursue efficiency gains throughout the PBR term.

Finally, the Hawaiian Electric Companies, a vertically integrated utility in Hawaii, will move to PBR starting in January 2020. Under the PBR framework, the Hawaiian Electric companies, including Hawaiian Electric Co ("HECO"), Maui Electric Company ("MECO"), and Hawaii Electric Light Co. Inc. ("HELCO") would operate under a five-year, multi-year rate schedule between rate cases. The PBR also has an annual revenue adjustment and includes an ESM that

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[239] Biewald, Bruce, Tim Wolf. *Performance-Based Regulation in a Restructured Electric Industry*. November 8, 1997. P. 27.

[240] Ibid.

[241] ESM provides for a 50/50 sharing of profits or losses outside the 350-basis point bandwidth of the return on equity of 10.559%.

[242] Currently, FortisBC is still under PBR.

provides both upside and downside sharing of earnings between the utilities and customers when earnings fall outside a commission-approved deadband. HECO, MECO, and HELCO proposed rewards and penalties tied to the timely approval of interconnection applications for distributed energy resources of less than 100 kW, the integration of various forms of distributed energy resources, and advanced metering adoption. The utilities also proposed to measure and track progress toward reductions in carbon emissions and carbon intensity, citing state legislation passed in 2018 that calls for zero net emissions of carbon by 2045.

6.2.11 Key considerations for Kansas in implementing PBR

PBR, while challenging in certain aspects, offers potential advantages over a COS approach. For instance, the PBR approach may reduce administrative and regulatory costs in the future due to fewer regulatory proceedings. PBR also leads to more stable rates for customers[243] because rates under an I-X approach will only increase by inflation less the productivity factor plus other flow-through mechanisms. Moreover, utilities are encouraged to operate more efficiently so they can achieve or surpass their productivity targets. Reliability can also be safeguarded under a PBR regime, especially for plans that have mandated performance standards, which in some jurisdictions also entail a system of penalties and rewards. Meanwhile, the sufficiency of capex funding under a PBR approach can be a concern if there are no other capital incentive mechanisms in place other than the I-X formula or if the explicit capital incentive mechanism provided is very restrictive. Including a capex mechanism within the PBR formula or, at a minimum, incorporating a hedging feature to reduce regulatory risks associated with capital outlays beyond the control of management may, in fact, provide for increased stability and ensure the longevity of a PBR mechanism.

Similar to any other regulatory framework, the implementation of the PBR regime also involves specific issues and challenges.

- **Forecasting requirements and challenges.** The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[244] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting on the side of the utilities can also lead to potential additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts can significantly deviate from actual figures, so the PBR design must include mechanisms that will provide a degree of protection to both the shareholders and ratepayers. These mechanisms may consist of re-openers, ESMs, true-ups, rebasing, and flow-throughs.[245]

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[243] Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29. November 27, 2003.

[244] Items to forecast include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

[245] In the UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to

Benchmarking and trend analysis can also be used to compare differences in actual costs and proposed costs and guide regulatory decisions, for example, in increasing or reducing the utilities' forecast expenditures.

- **Availability, accuracy, and consistency of data**. Data is often inconsistent or even unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes, and differences in accounting techniques, and mergers and amalgamations, to name a few. As mentioned earlier, data availability is a critical element in PBR. Harder forms of PBR require collating and employing multi-period information and data samples covering multiple utilities. Ensuring data consistency and credibility requires configuring systems and processes correctly. The utility can review current systems and record-keeping practices and configure them to capture the data required for filing. Appointing a Chief Data Officer - who can ascertain data accuracy and consistency - would be useful to prevent errors.

- **Funding requirements and financial viability.** Sources of funding in an I-X regime might not be sufficient under a non-steady state. Utilities are concerned that their financial viability may be undermined if there will be substantial capital expenditure requirements, which are not usually recognized in a timely manner in the PBR formula or if actual conditions depart from "test year" or historical conditions. Some regulators have addressed this issue by prescribing forward capital planning. Regulators are also dealing with such challenges through capex incentive mechanisms although such mechanisms complicate the administration of the PBR regime. In the same breath, some jurisdictions have incorporated adjustment factors within the PBR formula to address capital cost issues or have modified the PBR design, so it becomes a cross between COS and "comprehensive" forms of PBR.

- **Treatment of rewards for efficiency.** There is a concern that utilities will likely target efficiency gains in the early years of a regulatory period under PBR. This behavior is likely caused by the declining reward for efficiency over the regulatory period (in an I-X regime) and the practice of using the later years as the base year when resetting the rate for the next regulatory period. Furthermore, the practice of rewarding one type of cost savings and not the other often motivates utilities to change their spending profile to maximize returns. To address these concerns, an efficiency carry-over mechanism ("ECM") can be included in the PBR design. An ECM provides utilities with an ongoing incentive to operate efficiently throughout the entire regulatory period by allowing them to carry over the incremental earnings from efficiency gains into the next regulatory period. Utilities in Alberta (except for ENMAX) and Australia have ECMs. Another solution that removes the trade-off between operating and capital expenditures in economically inefficient ways is the elimination of the distinction between these two types of costs. The UK has done this in its 5th generation PBR (2010-2015) and treated both costs into "one pot." As

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declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

discussed previously, this concept is called the "totex" approach. This new approach has allowed utilities to select the incentive that best suits their business.

- **Service quality vis-à-vis incentives for savings.** There is a common concern from ratepayers and regulators that PBR's focus on the bottom-line and incentives for cost-cutting may lead to poor quality of service. Therefore, it has become increasingly common to require performance standards in the PBR formula. However, setting the criteria and financial incentives for performance requires additional administration and management.

PBR also need not be as complex as the I-X approach or the building blocks approach. As discussed earlier, PBR is a spectrum with different forms. A simple set of PIMs with rewards is also considered a form of PBR and can create incentives for regulated utilities to perform efficiently.

Key takeaways

In conclusion, Kansas can learn from the experiences and key success factors from other jurisdictions that have effectively implemented the PBR regime:

- **Reasonable rates for the protection of future investments**. Jurisdictions that have successfully implemented PBR set rates at a level that enables a utility to meet its obligations to customers as well as earn a commercially reasonable return to support necessary investments. PBR recognizes that any system should allow utilities to have sufficient funds for capital investment programs during the regulatory term. This recognition is anchored on the presumption that a reduction in returns to shareholders to levels below regulatory allowed targets may lessen their capital financing capabilities in the future because the cost of capital would increase (e.g., due to perceived additional risk for utility operation and lower returns).

- **Balanced targets for efficiency, productivity, and financial viability**. The targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. The X factor should also be informed by the consideration of opportunities for further productivity gains and cost reductions, customer growth, and capital funding.

- **Appropriate mechanism to manage risks**. In successful PBR regimes, the regulator has provided appropriate mechanisms to manage risks to customers and the utility for factors that are beyond the utility's control. These mechanisms include flow-throughs, exogenous factors, off-ramps, and reopeners. These mechanisms also address potential concerns about a perceived lack of flexibility of PBR mechanisms when there is a need to modify something, and the formulaic approach does not work.

- **Fair incentive and penalty mechanisms**. When adding explicit incentives to a price or revenue cap, the penalties and rewards should be commensurate with (i) the savings of the utility after reducing costs and (ii) the costs of the utility after improving performance.

- **Contextually developed and relevant models**. There is no "one size fits all" PBR formula. Stakeholders (regulators, regulated entities, and consumers) must work together and recognize their needs and develop their own path to PBR. A regulatory framework from another jurisdiction or utility may not work as well in another utility because of numerous factors such as inherent economic and market differences, business practices, policy-driven obligations, and regulatory or institutional requirements. Therefore, a PBR design needs to be customized to the specific environment and circumstances of the regulated utilities. The regulator needs to take the utility's unique characteristics, type of customers served, and underlying economy into account.

6.3 Economic development initiatives

Another option enumerated in Sub. for SB 69 to make Kansas retail electricity prices regionally competitive involves incenting more industry to come into the state through economic development initiatives. The intent would be to generate higher power sales and eventually help decrease rates for all ratepayers as utility fixed costs are spread over a larger customer base (namely existing customers, plus additional customers attracted through the initiatives). Stakeholders also mentioned during meetings that the high electricity rates in Kansas make the state less attractive to companies seeking to build or expand.

Economic development initiatives include programs that provide economic incentives to large industrial or commercial customers to maintain their businesses or facilities or to locate them within the utility's service territory. Providing economic development rates or riders ("EDRs") is one of these economic development initiatives. EDRs provide a discount from the utility's standard tariff rates or terms. Some utilities in Kansas, such as Empire District[246] and Evergy,[247] are already providing this rate schedule; the textbox below provides an example of the terms of one such EDR in Kansas.

Nevertheless, there is still a call from stakeholders to expand this program. Indeed, in support of economic development initiatives, the Kansas Industrial Consumers Group ("KIC") stated that "*Kansas is ideally positioned for industrial activity with transportation infrastructure (road/rail), central location, and a low-cost wind energy resource.*"[248] However, EDRs need to be carefully designed to avoid cross-subsidies within and between customer classes.

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[246] Empire District. "Rates." <https://www.empiredistrict.com/CustomerService/Rates/Electric/KS>

[247] Evergy. "Economic Development Rider Incentive." <https://www.evergyed.com/site-selection/edr-rider-incentive/>

[248] KIC written comments. P. 9.

Coffeyville's EDR

Coffeyville offers an EDR for new or existing and expanding customers to attract large commercial or industrial entities to the community. These new or expanding customers are defined as: (i) businesses that are newly locating in Coffeyville's service area; (ii) existing accounts that have been inactive for at least a year and a half; or (iii) existing accounts that are adding a demand load that is 100 kW or greater than the customer's historical bills from the past year. The discount is applicable to the new load portion of a customer's usage. To be able to avail of the EDR, the service must have a new demand load of 100 kW or greater with an annual load factor of 50% or higher. Service under this schedule is limited to 10 customers or a total aggregated demand load of 15 MW.

Customers with new loads greater than 100 kW but less than 1,000 kW may receive the following discounts from General Service under Demand Schedule GSWD-18:

Year 1	33.8%
Year 2	27.0%
Year 3	20.2%
Year 4	13.4%
Year 5	6.6%

Customers with additional loads of 1,000 kW or greater receive slightly lower discounts. The contract for this service will be six (6) years. Applications for the EDR are subject to approval by the governing body.

Source: Excerpt from Coffeyville. *Rate Schedule ED-18.*

6.3.1 EDRs in neighboring states

EDRs are not a new incentive mechanism, with many utilities across the country having offered this type of rate to commercial and industrial customers at one point or another. Of the six neighboring states reviewed, all have implemented some form of an EDR. A sample of the EDR programs available in each state is described in the subsections below. Overall, EDRs have been implemented to attract new customers to the state or expand load, and have been applied over the short-term, with most programs offered for a period of up to 5 years.

Oklahoma[249]

The Oklahoma Municipal Power Authority ("OMPA") has offered an EDR to qualifying industrial customers, accredited educational facilities, and/or government buildings since 1990. The program aims to enhance industrial development efforts in all of OMPA's member cities and is limited to an initial total capacity of 35 MW.

[249] Oklahoma Municipal Power Authority. *Economic Development Rate (EDR).* 2017.

Similar to Coffeyville's EDR, the EDR discounts offered by OMPA vary according to the level of new or additional load added by the customer. However, unlike Coffeyville, OMPA offers greater discounts to customers adding more load, with customers adding 1,000 kW or more of new or additional load receiving the highest discount. Figure 116 shows a breakdown of OMPA's EDR discount schedule, which is applied on a per kilowatt basis.

Figure 116. OMPA's EDR discount schedule

	Year 1	Year 2	Year 3	Year 4	Year 5
100 kW to 249 kW	15%	10%	5%	0%	0%
250 kW to 999 kW	25%	20%	15%	10%	5%
1,000 kW and above	50%	40%	30%	20%	10%

Source: Oklahoma Municipal Power Authority. *Economic Development Rate (EDR).* 2017.

Colorado[250]

In Colorado, House Bill 18-1271 authorizes the Colorado Public Utilities Commission to approve EDRs charged by IOUs to eligible commercial and industrial users. The Bill was signed into law by the Governor on June 1, 2018.

Unlike most of the EDR programs offered throughout Kansas' neighboring states, which are valid for five-year terms, the Colorado Bill enables EDRs to be offered for up to 10 years. The threshold for qualifying customers is also higher, as commercial and industrial customers only become eligible if their new or additional load exceeds 3 MW. Interestingly, in order for customers to qualify for the EDRs, they must "*demonstrate that the cost of electricity is a critical consideration in deciding where to locate or expand their business and that the availability of lower rates is a substantial factor*."

Missouri[251]

Ameren Missouri's Smart Energy Plan economic development incentive is available to commercial and industrial customers with an average monthly demand increase of at least 300 kW and a 55% load factor. These customers are eligible for an average 40% discount from base rates over an agreement term of five years.

North Dakota[252]

Customers of Montana-Dakota Utilities Co. in North Dakota are eligible for the utility's firm service EDR (Schedule 34) so long as their new or additional load exceeds 200 kW per month. The

[250] Colorado General Assembly. "Public Utilities Commission Electric Utilities Economic Development Rates." <http://leg.colorado.gov/bills/hb18-1271>

[251] Ameren Missouri. *Ameren Missouri's Smart Energy Plan Economic Development Incentive.* 2019.

[252] Montana-Dakota Utilities Co. *State of North Dakota Electric Rate Schedule.* June 26, 2017.

EDR, in this case, takes the form of a lower negotiated demand charge, which is valid for a period of five years and is increased gradually throughout the contract period.

South Dakota[253]

Heartland Consumers Power District, a South Dakota-based power supplier, offers an EDR through its Energy ONE incentive rate. Unlike most other EDRs discussed previously, Energy ONE removes the demand charge from the eligible industrial customer's bill and instead offers a lower energy-only rate that is fixed for a period of three years.

Arkansas[254]

Entergy Arkansas provides more flexibility with its EDR, although it is subject to similar requirements as the programs available throughout Kansas' neighboring states, including eligibility for a 5-year term and a threshold requirement for new or additional billing demand of 500 kW or greater on a monthly basis. In terms of differences, Entergy Arkansas offers its EDR to a wider pool of customers, including industrial customers, military installations, correctional facilities, extensive research facilities, large computer/data processing or service centers, and corporate headquarters. Entergy Arkansas also provides eligible customers with two options with regards to their discount schedules, as depicted in Figure 117 below. Options include a gradual reduction in the discount over a 5-year term, or a flat 30% reduction applied throughout the five-year term.

Figure 117. Entergy Arkansas' EDR options

	Year 1	Year 2	Year 3	Year 4	Year 5
Option 1	50%	40%	30%	20%	10%
Option 2	30%	30%	30%	30%	30%

Source: Entergy Arkansas, LLC. *Economic Development Rider (EDR)*. Effective February 1, 2019.

6.3.2 Impacts of EDRs

Based on the experiences of other jurisdictions, the implementation of EDRs can have both positive and negative impacts. The benefits are far-ranging, from job creation to improved efficiencies for utility systems. However, the potential drawbacks, including the free-rider problem and a focus on larger, energy-intensive businesses only, must also be considered.

[253] American Public Power Association. "Heartland Incentive Rate Sows Economic Development Seeds." February 13, 2018. <https://www.publicpower.org/periodical/article/heartland-incentive-rate-sows-economic-development-seeds>

[254] Entergy Arkansas, LLC. *Economic Development Rider (EDR)*. Effective February 1, 2019.

Figure 118. Benefits and drawbacks of EDRs

Sources: Illinois Commerce Commission. *Survey of State Economic Development Utility Rates and Policies: Staff Report.* 1994; Illinois Commerce Commission. *The Impact of Economic Development/Incentive Utility Rates on Illinois Business, with Special Emphasis on the Small Business Perspective.* 1987.

6.3.2.1 Benefits

The main motivation behind EDRs is to incent businesses to locate or expand their operations in a given state. This increased economic activity brings with it success in terms of job creation and private capital investment, which "*multiplies throughout the region in the form of increased spending in retail establishments, new housing starts, and population growth.*"[255] The additional load and broadened customer base attracted through EDRs also helps to lower rates for all customers, as the utility's fixed costs for generating and delivering electricity are now spread across more ratepayers.[256]

From the utility's perspective, additional load in one's service territory stimulates sales and enhances revenues. This ultimately aids in enhancing the utility's system efficiency, as the additional load utilizes any available excess generating capacity.[257]

6.3.2.2 Drawbacks

In terms of potential drawbacks, the minimum usage requirements inherent in the EDR structure, where customers become eligible for the discount only after surpassing a certain threshold,

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[255] Ameren Missouri. *Ameren Missouri's Smart Energy Plan Economic Development Incentive.* 2019.

[256] Illinois Commerce Commission. *Survey of State Economic Development Utility Rates and Policies: Staff Report.* 1994.

[257] Illinois Commerce Commission. *The Impact of Economic Development/Incentive Utility Rates on Illinois Business, with Special Emphasis on the Small Business Perspective.* 1987.

prohibits most 'small, non-energy intensive businesses' from accessing the incentive.[258] For example, Colorado's House Bill 18-1271 (as described in Section 6.3.1) specifies that EDRs are only to be offered to customers with new or additional load exceeding 3 MW, which is the highest threshold of all the states reviewed in this Study. In this case, the high load requirement clearly prohibits smaller businesses from obtaining EDR eligible status. Small businesses are an important component of a thriving economy and setting high eligibility thresholds tends to overlook this need to attract small businesses to the local economy.

Another drawback stems from the free-rider problem, where it is difficult to surmise whether the EDR-eligible customer would have still located or expanded their business to the utility's service territory had the incentive not been offered to them. Two types of free-riders exist: (1) those who locate or expand in the state but "*would have done so even if rates were not discounted*;" and (2) those who "*receive the full discount but would have expanded usage with a smaller discount.*"[259] In both cases, the EDR is not necessary to secure the new or additional load and results in lost revenues that the utility could have obtained by charging the customer, or free rider, the full rate.

6.3.3 Key considerations for Kansas in designing successful EDRs

There are numerous considerations that should be taken into account when designing an efficient and effective EDR. Figure 119 provides an overview of these criteria, with key questions highlighted in light blue, and additional considerations intended to elicit further thought highlighted in grey. These considerations are explored in more detail below.

First, is the EDR ***necessary*** to secure the load? Or asked a different way, will the customer choose to locate elsewhere or otherwise leave the system should the EDR not be offered?[260] If the answer is yes, then it can be inferred that the EDR is necessary. In order to make this determination, utilities and/or regulators in jurisdictions across the country have required customers potentially eligible for an EDR to provide evidence that this is the case. For example, as mentioned previously in the description of Colorado's House Bill 18-1271, customers must "*demonstrate that the cost of electricity is a critical consideration in deciding where to locate or expand their business and that the availability of lower rates is a substantial factor*."[261] Aside from a sworn affidavit, alternative forms of evidence can be submitted by the customer to demonstrate the EDR's necessity, such as documented communications with neighboring utilities scouting competing service, or financial reports demonstrating its financial distress or risk.[262]

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[258] Ibid.

[259] Ibid.

[260] International Association for Energy Economics. *Economic Development Rates: Public Service or Piracy?* 2016.

[261] Colorado General Assembly. "Public Utilities Commission Electric Utilities Economic Development Rates." <http://leg.colorado.gov/bills/hb18-1271>

[262] International Association for Energy Economics. *Economic Development Rates: Public Service or Piracy?* 2016.

Figure 119. Design considerations for EDRs

Sources: International Association for Energy Economics. *Economic Development Rates: Public Service or Piracy?* 2016; Consumers Energy, DTE Energy, and Michigan Electric and Gas Association. *What Are Other States Doing Regarding Rate Structures for Large Volume Users?*

Second, is the EDR ***sufficient***? Or, can it be minimized? This criterion seeks to overcome the free-rider problem, as an EDR should only be used to incent businesses to locate or expand to the state, and "*any discount beyond the minimum necessary to secure the load is a superfluous subsidy*."[263] As the free-rider problem is a difficult issue to quantify, this particular consideration requires a subjective assessment on the part of the utility and/or regulator.

Third, does the EDR exceed the ***marginal cost*** of providing electric service? This criterion is important to ensure the regulatory compact is upheld, such that utilities should be allowed to earn an appropriate return. Therefore, implementation of the EDR and serving the eligible commercial or industrial customers should not cause the utility to incur negative margins.[264] To ensure this is achieved, the EDR must be set such that it exceeds the utility's marginal cost of serving the eligible customers.

Fourth, does the EDR benefit ***all*** ratepayers? Or, at the very least, are other ratepayers made no worse off by the implementation of the EDR? As discussed in Section 6.3.2.1, the additional load secured through an EDR tends to expand a utility's customer base, thus easing the fixed cost contributions of all ratepayers on the system. Hence, by definition, the EDR should satisfy this criterion, as "*the other ratepayers benefit because this recovery of some utility fixed costs would not occur if the [additional] load were not served by the utility*."[265]

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[263] Ibid.

[264] Ibid.

[265] Ibid.

In terms of additional considerations, utilities and/or regulators must consider ***who*** pays for the discount. Jurisdictions across the country have either: (1) required shareholders to absorb the discount, or (2) required this responsibility to be shared between both the utility's customers and its shareholders, as both parties benefit from the EDR indirectly (with customers enjoying lower rates through an expanded customer base, and shareholders enjoying larger returns due to increased utility earnings).[266]

When designing EDRs, one must also consider whether additional ***eligibility*** requirements should be implemented, including thresholds for commercial and industrial customers relating to a minimum level of increased employment, or a minimum level of new capital investment.[267] Regulators can even associate eligibility with the location of the load, incenting new load to locate to "*targeted areas, including brownfield sites, vacant industrial buildings, economic or area development zones*" of the state.[268]

Finally, are there mechanisms in place to ensure the load is ***maintained*** once the EDR has ended? For instance, EDR schedules are usually offered such that customers obtain decreasing discounts over the course of their agreement with the utility. This aids in reducing the impact of rate shock and helps to ensure the benefits associated with the EDR are maintained once the discount has ended.[269]

Key takeaways

Economic development rates, which provide a discount from the utility's standard tariffs to eligible new or expanding commercial or industrial customers, help to attract businesses to the state. Utilities in six of the neighboring states reviewed in this Study have implemented some form of an EDR, with most programs offered for a period of up to 5 years. Before expanding the EDR offerings in Kansas, utilities and regulators will need to consider the following: whether EDRs are necessary to attract additional electric customers, whether the incentives are

6.4 Retail competition

The Sub. for SB 69 included retail competition as one of the options to be explored in this Study, although it should be noted that retail impacts only one portion of a consumer's total electric bill.

[266] Ibid.

[267] Consumers Energy, DTE Energy, and Michigan Electric and Gas Association. *What Are Other States Doing Regarding Rate Structures for Large Volume Users?*

[268] Ibid.

[269] Ibid.

Nonetheless, retail electric choice[270] essentially allows customers to buy electricity from a competitive electricity supplier other than their incumbent utility. For example, in the book titled *Making Competition Work in Electricity*, Sally Hunt defines retail competition as "the ability of different energy providers (retailers) to compete in the electricity market to sell residential, commercial, or industrial customers power at unregulated rates."[271]

There are three main ways of organizing the electricity sector that lead to varying levels of retail competition, as demonstrated in Figure 120 and described in further detail below.

Figure 120. Market design with and without retail competition

The traditional vertically integrated monopoly model is one where the utility handles all aspects of the electricity value chain, from generation through to transmission and distribution. Furthermore, the utility has a monopoly over its service territory, such that customers within it have no choice when it comes to their electricity provider.

Under the single buyer model, IPPs compete to provide power through long-term PPAs to that single buyer entity, which may or may not be independent of the utility operating the transmission and distribution functions. Similar to the vertically integrated monopoly model, the single buyer model limits customer choice.

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[270] Note that in some states, the gas market is also open to retail competition though there is little overlap between the states that have electric retail competition. Many of the big picture elements related to market design issues discussed here relate to the gas market.

[271] Hunt, Sally. *Making Competition Work in Electricity.* New York: John Wiley & Sons, 2002. Print. P. 430.

Retail competition emerges through the fully unbundled model, where competition is introduced in the distribution sector. As a result, transactions between all parties, namely generators, customers, and intermediaries, take place relatively freely. On the demand side, customers can choose their electricity provider and negotiate their own contracts, while on the supply side, generators are able to sell their electricity to any market participants.[272] Additionally, under the fully unbundled model, an ISO is established to coordinate grid functions, among other responsibilities.

The Kansas electricity sector does not fit neatly into any of these three models, and in fact, draws on a combination of elements from each of them. In this sense, Kansas' market is comprised of vertically integrated utilities (similar to the vertically integrated monopoly model), as well as a number of IPPs (similar to the single buyer model), all of whom are members of the Southwest Power Pool, which acts as the ISO for the region (similar to the fully unbundled model).

When retail choice is implemented, most states allow this access for different categories of customers, starting first with large commercial and industrial ("C&I") customers and then moving to small C&I and residential customers (sometimes referred to as "mass market" customers). Figure 121 below indicates the states across the country that have some form of retail competition in their electricity market, as well as the states for which there is also a presence of retail gas choice.

Figure 121. Presence of retail competition across the US, as of 2018

Source: Electric Choice. "Map of Deregulated Energy States & Markets (Updated 2018)." <https://www.electricchoice.com/map-deregulated-energy-markets/>

6.4.1 Different "flavors" of retail competition

There are significant variations in how retail competition has been implemented across the country, which affect the perceived benefits and challenges of retail competition. There are two

[272] International Energy Agency. *Energy Market Reform: Competition in Electricity Markets.* February 20, 2001. P. 55.

key parameters that determine this variation: (1) the role of the utility and its ability to offer an electricity supply product to retail customers, and (2) the level of active engagement that retail customers have in terms of selecting a new competitive electricity provider.

Historically, utilities have had a monopoly over customers in their service territory. With the advent of retail competition, there are several possible roles that the utility can take in terms of providing electricity service to retail customers, which fall on a continuum of low to high continued engagement. This continuum is summarized in Figure 122 and is discussed in further detail below.

Figure 122. Continuum of utility engagement under retail competition

The utility can take on any of the following roles under a competitive retail market:

- **Transmission and distribution provider –** the utility is prohibited from providing a retail electricity product to customers (its role is only to provide transmission and distribution service, not to interact with the customer);

- **Provider of last resort –** the utility is allowed to provide only last resort service should a retail electric provider go out of business, usually only for a temporary timeframe to avoid service disruption. This is the case in states such as California, Illinois, and New York, where incumbent regulated utilities act as providers of last resort ("POLR") under their obligation to serve;[273]

- **Basic service provider –** the utility is allowed to provide a "plain vanilla" electricity product to customers, such that only competitive retailers are able to offer innovative products and services to meet emerging customer interests; or

[273] California Public Utilities Commission. *California Customer Choice Project: Draft Gap Analysis/Choice Action Plan.* October 2018.

- **Provider of unlimited electricity supply products –** the utility is allowed to offer an unlimited number of electricity supply products to customers, alongside competitive electric providers. Product offerings can include service plans that provide customers flexibility in their energy purchases, hedging against price fluctuations through fixed prices, more choices for alternative energy resources (green power or power from renewable energy), and convenience in billing (such as through online payments).

At the same time, the role of the customer in terms of its retail activity is also important for defining the retail market design. In "direct" retail markets, the customer is directly marketed to by competitive electricity retail suppliers with targeted product offers that the supplier thinks will be attractive to the customer. The customer then makes an active choice about what kind of retail supply offer it wants to purchase.

Conversely, in "mass aggregation" retail markets, a municipality decides that it wants to seek a competitive supplier and runs a procurement process on behalf of its customers, which is usually focused on obtaining the lowest possible rate for customers but not on product or service innovation characteristics. Generally, customers have the right to opt-out of this service. Customers do not make a proactive choice about their competitive supplier or the product and are often unaware that their electricity is not supplied by the utility.

With this background in place, we can now examine the three main typologies of retail competition seen in the US. These include "pure" retail competition, as seen in Texas; a hybrid retail model, as seen in many of the Northeastern states that have retail competition; and the mass aggregation model, as seen in the Midwest and now California. We describe each in more detail in the subsections that follow.

6.4.1.1 Pure retail competition (Texas)

Texas is an example of the pure retail competition model, with full retail competition across all customer segments. Customer involvement in Texas' retail choice program is mandatory across all areas served by ERCOT.[274] Therefore, within the ERCOT service territory, customers are required to either choose a competitive supplier or have one assigned to them.[275] Munis and co-ops are exempted from deregulation, although these entities are able to opt-in if they so choose.[276]

Texas underwent restructuring of its retail electric market beginning in 1999 with the passing of Senate Bill 7, also known as the Texas Electric Choice Act.[277] Introduced and adopted

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[274] ERCOT serves about 90% of the state's electricity load. (Source: ERCOT. "About ERCOT." <http://www.ercot.com/about>)

[275] EIA. "Electricity residential retail choice participation has declined since 2014 peak." November 8, 2018. <https://www.eia.gov/todayinenergy/detail.php?id=37452>

[276] Currently, only one coop has opted in – Nueces Electric Cooperative ("NEC"). (Source: PUCT. "Certification and Licensing." <https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx>)

[277] PUCT. *Scope of Competition in Electric Markets in Texas.* January 2019.

unanimously during the State's 76th Legislative Session, the Bill called for the elimination of monopoly electric providers and gained support from lawmakers on the grounds that competition and market forces would drive Texas' already low electric prices even lower.[278]

Under the Bill, former vertically integrated utilities were required to unbundle their businesses into three distinct entities:

(i) a power generation company ("PGC") that owns and operates the electric generation capacity and bids it into the wholesale market;

(ii) a regulated transmission and distribution company that owns and operates the wires segment; and

(iii) a deregulated retail electric provider ("REP").[279]

The deregulated retail market officially opened on January 1st, 2002.[280] To facilitate competition early on and encourage the entry of unaffiliated REPs (namely REPs that were not unbundled from legacy utilities), a temporary rate freeze was introduced through a price to beat ("PTB") mechanism. Under the mechanism, affiliated REPs were required to charge their customers the PTB, thus protecting non-switching customers from excessive price hikes and also creating a benchmark which competing REPs could undercut.[281] By December 2006, the PTB mechanism was terminated amidst healthy competition in the state's electric retail sector.

The success of retail competition in Texas can be measured through customer switching rates, as well as the growth in the number of retail energy providers and available offers in the market. Since the implementation of retail competition in the state, approximately 94% of customers have exercised their ability to choose their electricity provider.[282] By 2018, 116 REPs were operating in ERCOT, up from ten providers in 2002.[283,284] Within the same time period, the number of unique product offerings rose from 11 in 2002 to 315 by 2018 (77 of which offer 100% renewable electricity).[285,286] Additional product offerings include fixed pricing for 3 to 36 months; variable

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[278] Cities Aggregation Power Project, Inc. *The History of Electric Deregulation in Texas.* 2009.

[279] Ibid.

[280] Ibid.

[281] PUCT. *Retail Competition in Texas: A Success Story.* June 8, 2011.

[282] ERCOT. *Observed Selection of Electric Providers September 2017 – September 2018.* October 1, 2018.

[283] PUCT. *Scope of Competition in Electric Markets in Texas.* January 2019.

[284] Association of Electric Companies of Texas. *The Retail Electric Market in ERCOT.* 2017.

[285] PUCT. *Scope of Competition in Electric Markets in Texas.* January 2019.

[286] Association of Electric Companies of Texas. *The Retail Electric Market in ERCOT.* 2017.

pricing (changing market price after the first billing cycle); time-of-use prices; electric vehicle recharging prices; solar buy-back prices; promotional rates, money-back offers, and cash discounts; guaranteed cost-per-month contracts; and prepaid energy service.

In terms of rate impacts, retail rates have decreased by 31% since ERCOT's transition to retail competition.[287] Average retail rates across the competitive market in the state (10.3 cents per kWh as of September 2018) are also lower than the national average (13.02 cents per kWh as of June 2018).[288] Overall, ERCOT has one of the highest switching rates in the country, with its retail market deemed among the most successful at facilitating choice for all consumers.

6.4.1.2 Hybrid model (Northeast)

While Texas provides an example of the pure retail competition model, many examples of the hybrid approach to deregulation exist across the Northeastern US. As our aim is solely to examine the typologies of retail competition at a high level, we will take Pennsylvania as a representative case study. As mentioned previously, participation in the competitive retail market in ERCOT is mandatory. Conversely, under the hybrid approach, customers in Pennsylvania have two options:

(i) remain with the local utility company (electric distribution company, or "EDC") to fulfill their generation needs; or

(ii) switch to purchasing power directly from an independent electric generation supplier ("EGS").[289]

This choice was enabled through the adoption of the Electricity Generation Customer Choice and Competition Act in 1996, as the market competition was expected to control electric costs better than regulation.[290] At the time of deregulation, Pennsylvania was facing many of the same issues that Kansas is currently facing: Pennsylvania's electric rates were 15% higher than the national average, which was seen as a hindrance to economic development in the state; and the state was suffering from wide rate disparity.[291,292] By the end of 2018, Pennsylvania's electric rates were 4% lower than the national average.[293]

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[287] PUCT. *Scope of Competition in Electric Markets in Texas.* January 2019.

[288] Ibid.

[289] Pennsylvania PUC. *PA Power Switch – Shop. Switch. Save.*

[290] NARUC. *Pennsylvania's Retail Markets.* May 14, 2008.

[291] Kleinman Center for Energy Policy. *A Case Study of Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead.* October 28, 2016.

[292] NARUC. *Pennsylvania's Retail Markets.* May 14, 2008.

[293] US Energy Information Administration. *Form EIA-861, Annual Electric Power Industry Report.* January 2019.

To combat these issues, lawmakers called for the restructuring of Pennsylvania's wholesale and retail electricity markets.[294] Under the Act, EDCs were required to unbundle their generation, transmission, and distribution rates for retail customers, while deregulation was introduced in the state's generation sector.[295] To ease the transition to competition, a rate freeze was implemented until the end of 2010, and access to the retail market was staggered based on customer class.[296,297]

Ultimately, through the introduction of competition in the generation sector, the role of utilities had to be redefined. Currently, EDCs are responsible for transmitting and distributing electricity to end customers, regardless of whether the customer has switched to an EGS or remains with the EDC.[298] In addition, EDCs have also taken on the role of the default service provider, supplying electricity to customers who do not exercise their right to choose through a rate referred to as the price to compare ("PTC").[299]

By 2018, 115 EGSs were active in the state, offering programs including flat and time-varying rates, fixed-term contracts, as well as curtailable and green power products.[300] In terms of customer switching, on average, 33% of customers across all segments in Pennsylvania utilized their ability to shop for competitive suppliers by 2018, with 31% of all residential customers and 45% of non-residential customers served by EGSs.[301] This has increased since 2010 (the first year for which annual reporting on retail electric choice was undertaken by the Pennsylvania PUC), where on average only 12% of all customers were being served by EGSs, including 11% of residential customers and 17% of non-residential customers.[302] This trend is illustrated in Figure 123 below, which tracks the percentage of customers served by EGSs from 2010 to 2018 by customer class.

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[294] Kleinman Center for Energy Policy. *A Case Study of Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead.* October 28, 2016.

[295] Pennsylvania PUC. *A Guide to Utility Ratemaking.* 2018.

[296] NARUC. *Pennsylvania's Retail Markets.* May 14, 2008.

[297] Pennsylvania PUC. *PA Power Switch – Shop. Switch. Save.*

[298] Pennsylvania PUC. *A Guide to Utility Ratemaking.* 2018.

[299] Ibid.

[300] Pennsylvania PUC. *Retail Electricity Choice Activity Report.* 2018.

[301] Ibid.

[302] Ibid.

Figure 123. Customers served by EGSs, 2010-2018

Source: Pennsylvania PUC. *Retail Electricity Choice Activity Report.* 2010-2018.

6.4.1.3 Mass aggregation model (Midwest)

The final competitive retail model is the mass aggregation approach, which requires the lowest level of active customer engagement. Illinois adopted this approach in 2009, through Section 1-92 of the Illinois Power Agency Act.[303,304] The Section allows for government aggregation, whereby municipalities and counties are able to enter into wholesale bulk electric supply contracts with retail electric suppliers ("RESs") on behalf of their residential and small commercial customers.[305] Aggregation programs are offered on both an opt-out and opt-in basis, although communities in the state more often pursue opt-out programs.[306] Under the aggregation model, the local regulated IOU maintains responsibility for the distribution function of the market, mirroring the approaches seen in Texas and Pennsylvania.[307]

Following the introduction of mass aggregation, Illinois experienced among the highest growth in residential customer switching rates in the country. This was due in part to declining natural gas prices, which enabled RESs to offer more competitive rates than IOUs, who are subject to

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[303] Illinois General Assembly. *Illinois Power Agency Act.* August 28, 2007.

[304] EIA. "New aggregation programs drive consumer participation in Illinois electricity choice." January 24, 2013. <https://www.eia.gov/todayinenergy/detail.php?id=9691>

[305] EIA. "Participation growth in Illinois residential retail choice programs has leveled off since March 2013." September 25, 2014. <https://www.eia.gov/electricity/monthly/update/archive/september2014/>

[306] Plug In Illinois. "Municipal and County Electric Aggregation." <http://www.pluginillinois.org/MunicipalAggregation.aspx>

[307] EIA. "New aggregation programs drive consumer participation in Illinois electricity choice." January 24, 2013. <https://www.eia.gov/todayinenergy/detail.php?id=9691>

regulatory rules and are thus less responsive to fluctuations in power prices.[308] By 2014, customer switching reached its peak in Illinois, with around 57% of residential customers served by retail choice providers. However, by 2015, following commodity price trends, 16% of residential customers had switched back to their local utility, followed by another 18% in 2016.[309] Figure 124 below tracks the number of residential customers in Illinois served by RESs from 2011 to 2018.

Figure 124. Residential customers served by a RES, 2011-2018

Source: Plug-In Illinois – Power of Choice. *Residential Electric Switching Statistics*. September 2019.

One limitation of the mass aggregation model is its boom and bust nature, which is highlighted in the figure above. In 2014, Illinois experienced a spike in customers switching to RESs, as competitive retailers were able to undercut IOU rates by taking advantage of declining natural gas prices. However, following this, the reverse occurred – customers switched back to their local utilities as it was the IOUs now that were able to maintain lower rates. This tendency for customers to switch back and forth, depending on which supplier offers the lowest rate makes creating a sustainable retail business particularly challenging.

Although the price is often cited as the main driver behind customer switching under the mass aggregation model, this form of retail competition is also implemented to pursue programs that are not traditionally offered by IOUs, such as green procurement. The textbox below highlights California's experience with mass aggregation as a means to procure more renewable energy.

[308] EIA. "Electricity residential retail choice participation has declined since 2014 peak." November 8, 2018. <https://www.eia.gov/todayinenergy/detail.php?id=37452>

[309] Ibid.

Community choice aggregation in California

Community choice aggregation ("CCA") provides a means of *"aggregating the electric load of a community for the purpose of contracting for power that is greener and cheaper than the incumbent utility."* In California, CCAs are the sole alternative supplier to the local IOU for most customers, and function as an opt-out program similar to most government aggregation programs in Illinois.

CCA offerings can include solar net energy metering tariffs, feed-in tariff incentives for local solar projects, as well as energy efficiency and demand response programs. Generally, CCAs in California offer two levels of service:

- default service with a 35-55% renewable electricity offering; or
- a more expensive 100% renewable electricity option.

Source: Lean Energy US. *CCAs and the Path to Local Economic Development and Energy Innovation: California Case Studies*; Lean Energy US. "California." <https://leanenergyus.org/cca-by-state/california/>

6.4.2 Benefits and challenges of retail competition

Deciding whether to implement retail competition requires careful consideration of the potential benefits and challenges that come with it. The following section presents evidence of the benefits associated with retail choice, as it relates to electricity prices to end consumers, consumer choice, as well as innovations in product offerings. Conversely, LEI also discusses the challenges of implementing retail competition, including the regulatory processes that are required for transition, the need to adequately protect residential customers, as well as the additional costs that arise through retail choice.

6.4.2.1 Benefits

6.4.2.1.1 Price

Assessing the direct impact that retail competition has had on electric rates across the US is a challenging area of research, as comparisons need to be drawn across states with differing market designs and localized conditions, including *"load factor and seasonal usage patterns, generation fuel mix, transmission congestion, taxation and wage levels, weather, and regulatory decisions that allocate costs among customer classes*."[310] Retail rates also vary according to wholesale electricity prices, customer load profiles, marketing costs, duration of contract terms, as well as whether rates are variable or fixed, making it hard to capture the value of these varied product offerings.[311]

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[310] RESA. *The Great Divergence in Competitive and Monopoly Electricity Price Trends.* September 2018.

[311] RAP. *Restructured States, Retail Competition, and Market-Based Generation Rates.* August 31, 2015.

Taken together, these factors make comparisons on an apples-to-apples basis particularly difficult, and thus culminate in conflicting evidence, with groups supporting retail competition finding that states with retail choice have lower prices, and groups against retail competition asserting the opposite. As it is outside of scope for LEI to conduct the detailed analysis that would be required to make a more determinative finding, we will instead be presenting research and findings from reputable sources that lie on either side of the debate.

Conflicting evidence regarding the directional impact on rates under retail competition is partly fueled by the volatility in electricity prices among retail choice states. Using EIA data as far back as 1990, Figure 125 below highlights that among states with full retail competition (i.e., excluding partially open retail markets), average retail prices are more volatile than those in non-retail states. This rise and fall in electricity prices to end consumers in retail choice states can be attributed to corresponding movements in natural gas prices.[312]

Figure 125. Percentage change in retail price from the previous year, retail vs. non-retail states

Source: NREL. *An Introduction to Retail Electricity Choice in the United States.* August 2017.

The motives and drivers behind implementing retail competition in the case studies covered in Section 6.4.1 stemmed mainly from a desire to lower rates for customers and foster innovation in the market. As such, it is important to verify whether this was indeed the outcome.

In a comparison of the weighted average nominal prices for all customer classes between retail and non-retail states from 2008 to 2017, it was found that prices in non-retail states rose by 18.7%,

[312] NREL. *An Introduction to Retail Electricity Choice in the United States.* August 2017.

while prices in retail states declined by 7% over the same time period.[313] This difference in trajectories from 2008 onwards can be attributed to the flexibility inherent in the competitive model in response to market conditions, including declining demand and natural gas prices. In relation to the first, *"it should be no surprise that in a decade of flat or declining load, traditional regulation would exert upward pressure on prices because power plant investment must be compensated even if there is weak demand[;] in competitive markets, weak demand will tend to exert downward pressure on prices for generation."*[314] This finding of diverging trajectories in retail rates, declining in retail choice states and rising in non-retail states, has been confirmed in other studies.[315]

On the other hand, other studies have found evidence that electricity prices are higher on average in retail choice states as compared to non-retail states.[316] For instance, using data from a national survey of average monthly bills for electric customers across 106 cities, customers in retail choice states were found to face higher bills than those in non-retail states, with bill differences ranging from 37% for residential customers to 70% for industrial customers.[317] However, it is important to recognize that many of the states implementing retail choice had higher prices even before competition was introduced, when they were operating under similar regulatory models as the non-retail states, driven by higher costs of generation and other factors.[318]

6.4.2.1.2 Consumer choice

One of the major benefits of retail competition is the variation in electricity supply products and services that customers are able to choose from. Retail electric competition is what has first sparked end consumers' interest in renewable energy products. For example, in 2018 approximately 1.7 million customers throughout the country procured 25 million MWh of renewable energy through competitive suppliers.[319] Figure 126 below demonstrates this trend of rising green procurement as a result of retail competition over the past two decades.

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[313] RESA. *The Great Divergence in Competitive and Monopoly Electricity Price Trends.* September 2018.

[314] Ibid.

[315] See: Ros, Agustin J. "An Economic Assessment of Electricity Demand in the United States Using Utility-specific Panel Data and the Impact of Retail Competition on Prices." *The Energy Journal* 38.4 (2017): 73-99; RESA. *Restructuring Recharged: The Superior Performance of Competitive Electricity Markets 2008-2016.* April 2017.

[316] Electric Markets Research Foundation. *Retail Choice in Electricity: What Have We Learned in 20 Years?* February 11, 2016.

[317] Ibid.

[318] RESA. *The Great Divergence in Competitive and Monopoly Electricity Price Trends.* September 2018.

[319] NREL. *Status and Trends in the Voluntary Market (2018 data).* September 6, 2019.

Figure 126. Trends in green procurement, 1998-2018

Sources: NREL. *Status and Trends in the US Voluntary Green Power Market.* 2003-2019.

In addition, competitive retailers, whose executives often hail from the fast-moving consumer goods sector or from the financial, retail services sector, have also designed numerous customer service offerings, from differentiated pricing options (longer-term fixed prices for customers looking to hedge their energy price risk exposure, flat monthly billing for those on a fixed income, free nights and weekends for those that rarely consume electricity during on-peak hours, time of use pricing for those that are able to shift their consumption to lower price periods) to differentiated services levels (all online service, in-state "local" call centers, premium customer service). These variations have given consumers the ability to tailor their electricity service contract to their specific needs. A sample of these electricity plans is presented in Figure 127.

Figure 127. Sample of customer service offerings

	reliant an NRG company	TXU energy	Green Mountain Energy	Direct Energy
Plan	**Reliant Truly Free Weekends**	**TXU Energy e-Saver 10**	**Pollution Free e-Plus 36**	**Free Nights Electricity**
Details	Offers residential customers free weekend usage from 8 pm on Friday to 12 am on Monday	A 10-month plan where customers receive a 0.8 cent per kWh discount for conducting all business online, including Autopay, paperless billing	Provides residential customers with 100% clean wind energy at a fixed price for a 36-month term	Offers free electricity every night from 9 pm to 9 am, as well as price protection through a fixed rate for 12 months

Sources: Reliant; TXU Energy; Green Mountain Energy; Direct Energy.

Thus, the implementation of retail competition opens up the possibility for customers to have a variety of products and service offerings related to their electricity supply to choose from, similar to what they currently experience in their cell phone, cable, and security services. Customer satisfaction surveys within retail choice states indicate that Texas, which offers the greatest level of customer choice of the case studies examined in Section 6.4.1, scores the highest (730/1000)

when ranked in terms of price, communications, corporate citizenship, enrollment/renewal, and customer service.[320]

6.4.2.1.3 Innovation

Retail competition has also unleashed significant innovation in the electricity supply sector. As mentioned earlier, retail competition helped spur consumer interest in renewables. That interest led to a considerable variety in renewable electricity products, ranging from 25%-100% renewables to 100% in-state renewable solar content. There are even renewable gas products on the market.[321]

Retailers also helped create new types of renewable innovation products, such as community solar. According to the Solar Energy Industries Association, *"community solar refers to local solar facilities shared by multiple community subscribers who receive credit on their electricity bills for their share of the power produced."*[322] Figure 128 below illustrates the typical structure of a community solar program.

While community solar is increasingly prevalent, it was essentially pioneered by Green Mountain Power, a renewable retailer, more than 15 years ago. Green Mountain offered its customers the ability to contribute to a Sun Club, which built solar facilities at local community organizations and schools around Texas. More recently, community solar projects have been targeted at low-income communities as a way to expand access to the economic and environmental benefits of solar power.[323] By 2018, around 1,523 MW of community solar had been installed throughout most of the US, with 40 states reporting at least one operational project within their communities.[324]

Similarly, Green Mountain was also the first to develop a retail price for homeowners and businesses with on-site solar, offering them the prevailing retail rate to "buy back" the solar produced that was in excess of their needs. Green Mountain and other retailers are also offering such innovative products to owners of electric vehicles, providing them with an economic incentive to charge their cars at night, during low-cost hours. Indeed, some of these offers are

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[320] J.D. Power. "Residential Customers Resistant to Changing Retail Electric Providers as Price Gap Closes." August 10, 2016. <https://www.jdpower.com/business/press-releases/jd-power-2016-retail-electric-provider-residential-customer-satisfaction-study>

[321] Renewable natural gas ("RNG") is *"methane gas produced by landfills, manure digesters, sewage treatment plants, and other biological sources"* and can be used in place of natural gas for things such as powering vehicles or heating homes. (Source: Energy News Network. "Renewable Natural Gas." <https://energynews.us/tag/renewable-natural-gas/>)

[322] SEIA. "Community Solar." <https://www.seia.org/initiatives/community-solar>

[323] Ibid.

[324] Ibid.

100% renewable so that consumers can rest assured that their electric car is not being fueled by fossil fuel-generated electricity.

Figure 128. Basic community solar program structure

Source: Adapted from NREL. *Status and Trends in the Voluntary Market (2018 data).* September 6, 2019.

Other innovations in the retail electric sector are on the marketing side. Retailers offer a plethora of attractive incentives and rewards for customers, such as reward programs, cashback, a free smart thermostat, or access to a free energy audit.

6.4.2.2 Challenges

6.4.2.2.1 Regulatory processes required for the transition

Opening the retail electric market to competition is a market design change from the traditional monopoly electricity service. As such, there has to be, at a minimum, a regulatory proceeding to facilitate it, though many jurisdictions also incorporate such changes into legislation. Such processes need to be preceded by a stakeholder process, all of which entail time and resources. Most of these activities were undertaken, in one form or another, by the three jurisdictions examined in Section 6.4.1 – the timelines for these activities are summarized in Figure 129 below.

As highlighted in the figure, transitioning to retail competition is a lengthy process that can span decades and often involves the following general activities: enacting enabling regulation/legislation; phasing in or staggering retail access by customer segment; potentially implementing rate freezes or other mechanisms to encourage entry of competitive suppliers; setting up committees or organizations to oversee the functioning of the retail market; assessing and monitoring the state of the market through regulatory proceedings; as well as updating and amending market rules to enhance the competitiveness and efficiency of the market.

Figure 129. Timeline of transitioning to retail competition for select states

Source: Distributed Energy Financial Group. *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS)*. July 2015.

6.4.2.2.2 Need to adequately protect residential customers

Introducing competition in the retail electric market means providing residential customers access to many alternative suppliers. In order to ensure customers are able to make informed choices, some states such as Illinois and New York have been focusing extensively on implementing stronger consumer protection rules.

Consumer protection rules in Illinois are centered on regulating the marketing practices of RESs to ensure adequate disclosure and transparency, not only during the solicitation period when RESs are trying to secure new customers but also throughout the duration of their contracts with existing customers. These rules were adopted by the Illinois Commerce Commission ("ICC") as amendments to 83 Ill. Adm. Code 412, Obligations of Retail Electric Suppliers ("Rule 412") in November 2017, which RESs in the state had to comply with no later than May 1st, 2018.[325] A sample of these requirements is presented in Figure 130 below.

[325] ICC Office of Retail Market Development. *Annual Report to the General Assembly, the Governor, and the Illinois Commerce Commission*. June 2018.

Figure 130. Consumer protection rules in Illinois

Source: ICC. *Docket 15-0512. Final Order - Appendix A.* October 19, 2017.

As for New York, its Public Service Commission ("PSC") introduced rules relating to consumer protection as early as 1998, through its first draft of Uniform Business Practices ("UBP").[326] These procedures, designed to guide Energy Service Companies ("ESCOs") and utilities throughout the state, were most recently revised and adopted on January 19th, 2018.[327] This round of revisions reflects the evolving nature of the competitive retail energy market, and includes provisions to protect customers in the following areas:

- **enhancing the readability of customer agreements** – all sales agreements must be written in plain language;
- **improved record keeping in the event of a customer dispute** – ESCOs are required to retain documentation of customer enrollment for the duration that the customer remains with the ESCO and two years thereafter; and
- **offering voluntary budget billing or levelized payment plans for the payment of charges** – which allows customers to track their electricity usage and potential excess charges.

[326] NY Department of Public Service. "Uniform Business Practices." <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8DD2B96E91D7447E85257687006F3922?OpenDocument>

[327] NY PSC. *Case 98-M-1343: Order Adopting Revised Uniform Business Practices.* January 19, 2018.

6.4.2.2.3 Additional costs

Implementing a competitive retail market does incur some additional costs for utilities, including those associated with executing new billing procedures, as well as investing in metering infrastructure that aligns with the product offerings from competitive retailers. Both requirements alter the administrative operations of the utility and are discussed in further detail below.

In terms of billing, utilities may be charged with the duty of acting as billing agents on behalf of both themselves and retailers. If this is the case, utilities must adapt their procedures to ensure they are adequately billing customers for:

- non-competitive services such as electric delivery (which is generally handled by the utility); and
- competitive services relating to electric usage (which is supplied by the retailer).[328]

Estimates for implementing new billing procedures have been far-ranging, but some cited line items have included: programmer labor costs needed to reprogram utilities' customer information systems; additional printing costs for longer bills with more pages; additional paper and ink costs required to add bill line items; weight-related postage increases; and training of customer service representatives.[329] For example, in a submission to the New York PSC, major utilities in the state provided estimates for the costs and timelines of implementation of new billing procedures – these were as far-ranging as $75,000 to $4.8 million, and three months to two years in terms of timing.[330]

As for investments in metering infrastructure, these will be undertaken by utilities only in cases where current metering infrastructure is not compatible with retail service offerings. Investments may be necessary to upgrade meters to allow for: finer time differentiation to enable hourly metering; peak demand metering; or bidirectional flow measurement, which is needed in the case of self-generation.[331]

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[328] Electric Markets Research Foundation. *Retail Choice in Electricity: What Have We Learned in 20 Years?* February 11, 2016.

[329] NY PSC. *Case 00-M-0504: Order Directing Submission of Unbundled Bill Formats.* February 18, 2005.

[330] Utilities and their respective estimates were as follows: (1) Con Edison: $4.8 million, 18 months; (2) Orange and Rockland Utilities: $1.5-2.5 million, 8-12 months; (3) Niagara Mohawk: $75,000-100,000, 3-4 months; and (4) Central Hudson: 2 years, no cost estimate. (Source: Ibid).

[331] Electric Markets Research Foundation. *Retail Choice in Electricity: What Have We Learned in 20 Years?* February 11, 2016.

6.4.3 Process to achieve retail competition

The implementation of retail market liberalization tends to follow similar patterns across different jurisdictions, albeit at different paces. This general process is summarized in Figure 131 and is discussed in further detail below.

Figure 131. Process of implementing retail competition

The first is the regulatory process. The retail market opening needs to be officially legislated or regulated, which generally is preceded by a stakeholder process to obtain input from key stakeholders such as the utilities, retailers, and consumer groups. That process usually will define which customers are able to choose their electric supplier, at which point in time. Most markets open up the retail market for larger customers first and then transition to smaller customers.

Moreover, that process will need to define whether utilities continue to offer an electricity service product to customers who do not choose a competitive supplier and if so, what the nature of that product will be and how it should be procured. Regulators will also need to determine whether the utility is allowed to have a competitive retail affiliate, whether that affiliate can use the utility's name, and what the appropriate code of conduct for affiliate relations should be. The requirements for retailers, which must be licensed by the regulator, will also be defined at this point. At this time or soon thereafter, regulators will also need to define a code and process to protect small consumers from any predatory or overly aggressive marketing behavior and to address customer privacy concerns.

The regulatory process will set the framework for the new retail market. Once that framework is established, a working group of regulators, utilities, and retailers need to work out the mechanics of how the retail market will function on a day to day basis. This includes topics such as: how can the retail access utility customer consumption data; how will customers be switched from utility to retailer or from retailer to retailer; what happens if a retailer goes out of business; how will retailers bill customers; are changes needed to the utility billing system to enable competitive retail billing; how will bad debt expenses be handled – can they be "purchased" by the utility to include them into their rate base; if the utility will be offering a default supply product, how will the utility/utilities procure that product and price it.

Finally, the third major component to a retail market opening is consumer education. In markets where customers have only purchased electricity from their incumbent utility, regulators need to plan and implement a clear education and communication process, leveraging different vehicles to target as wide an audience as possible. Examples include commercials, billboards, signs on buses, meetings in local community centers, and a tailored website for explaining how and why to change suppliers. Most jurisdictions also create an independent website that compares electricity offers by different suppliers on the term, price, renewable content and other offer characteristics. Figure 132 provides an example of one such website, namely the PUCT's electric choice website "Power to Choose."

Figure 132. Example of a price to compare website

Source: Power to Choose. "Shop. Compare. Choose." <http://powertochoose.org/en-us/Plan/Results>

6.4.4 Key considerations for Kansas in designing a successful retail market

There are several key issues for the successful implementation of a retail electric market:

- **Successful wholesale competition with adequate protection from market power abuse as well as ensuring adequate levels of generation.** While this is outside the scope of retail market opening, lack of robust wholesale competition and insufficient generation capacity would make it impossible to establish a sustainable competitive retail market.

- **Gradual phasing in of retail choice may be necessary to avoid stranded costs**. Stranded costs may arise if customers switch to competitive suppliers to obtain lower cost power supply, while incumbent utilities are locked into long term supply contracts. Phasing in

retail competition over time and requiring utilities to start letting such contracts expire or not signing new ones would reduce the impact on their financial viability.

- **Stable and predictable regulatory environment** whereby market participants have confidence in the stability of market rules, the fairness of the regulatory process, and ensuring that incumbent utilities do not have an unfair advantage.

- **To the extent that regulators decide to implement a utility provided default service, it is important to ensure that it is not to the detriment of competitive suppliers.** Thus, the default service should be provided as a transitionary step with a firm end date. Default service rates should be consistent with market prices faced by retailers, and default service products offered by utilities should be limited to "basic" service, to allow retailers only to offer innovative products and services.

- **Processes and infrastructure should be established to facilitate the retail market**. Customer data should be easily accessible to customers and, if with customer permission, to retailers. Transaction costs for retailers should be minimized by providing arrangements such as combined utility billing and purchase of receivables. The regulator should design and manage a robust customer outreach and education campaign related to retail choice and information regarding the switching process, retailers, and pricing.

Stakeholder feedback on retail competition in Kansas

Generally, most stakeholders in Kansas seem averse to the notion of retail competition. Of the options to be assessed as part of this Study under Sub. for SB 69, retail choice is seen as the least viable option by some. Others are cautious, pointing to the lack of consensus in research showing that retail competition benefits residential customers. As a whole, the overwhelming perception among stakeholders is that implementing retail competition is a time consuming, complex process, and that it may not be as good of a fit in Kansas as it has been in other states that have implemented it.

Key takeaways

Deciding whether retail competition is right for Kansas will require consideration of numerous factors. First, will retail choice help to decrease costs for consumers? Previous experience from multiple jurisdictions across the country suggests that the answer to this question is yes. Next, how could Kansas explore this transition? This would most likely involve convening a panel of utilities, large customers, as well as representatives of small customers to collect their feedback and ascertain their interest in implementing retail choice in the state. Of course, introducing retail competition is a large regulatory lift, which can span several years. Thus, another consideration would have to be whether the perceived costs outweigh the perceived benefits. An alternative option would be to open retail competition only to C&I customers, but this again depends on their relative interest.

6.5 Investments in energy efficiency and renewable energy

Located in the Great Plains region, Kansas has an abundance of wind and solar resource, with some of the best resources of wind in the US. With a large agricultural sector, biomass feedstock is also available for generation. Similarly, with a robust hydrocarbon extraction industry, and other large industries located in Kansas, energy efficiency potential exists in the state. In this section, we consider the current status of renewables – defined as wind, solar and biomass – and energy efficiency initiatives in Kansas. We evaluate the drivers for the build out of renewables in the state, and whether these drivers are expected to persist going forward.

6.5.1 Renewables

As of July 2019, Kansas had a total renewable installed capacity of over 6 GW.[332] This is comprised of over 5.5 GW of installed wind capacity,[333] and just under 30 MW in installed solar energy.[334] Almost all renewable electricity generation in the state comes from wind power, and Kansas has the largest share of electricity generated from wind energy in the United States at 36%.[335]

The development of renewable energy in the state has been driven primarily by the excellent wind resource in the Great Plains region, availability of transmission capacity to deliver surplus energy to regional markets, and favorable federal policies that provide a financial incentive for renewable energy. A number of these are discussed below.

Kansas has vast renewable energy potential, as demonstrated by previous studies on US renewable potential. Kansas is ranked 2nd in the United States for wind energy potential (as shown in Figure 133 below), with projections indicating that the state could provide over 7 GW for export from wind energy each year by 2030. Kansas is ranked fourth in total biomass production, with an annual production capacity of 60 million gallons per year, driven by a strong agricultural sector that provides abundant feedstock.[336]

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[332] "U.S. Energy Information Administration - EIA - Independent Statistics and Analysis." *Kansas - State Energy Profile Analysis - (EIA)*, Mar. 2019. Accessed at: <www.eia.gov/state/analysis.php?sid=KS#64.>

[333] AWEA. *Third Quarter 2019 Market Report*. 2019.

[334] Additionally, there are twelve ethanol plants operating in the state with a combined capacity of 500 million gallons and one bio-diesel plant with a production capacity of 1 million gallons per year. (Source: EIA. *Monthly Biodiesel Production Report*. January 2019).

[335] EIA. *State Profile and Energy Estimates: Kansas.* March 21, 2019.

[336] Ibid.

Figure 133. Average wind speeds in the US

Source: AWS Truepower. WINDExchange, November 2019.

The Kansas Legislature enacted the Renewable Energy Standards Act ("RESA") in May 2009, creating an RPS. The Kansas RPS required the state's IOUs and electric co-ops to generate or purchase 10% of their peak demand capacity from eligible renewable resources from 2011 through to 2015, 15% from 2016 through 2019, and 20% of their total electricity each year from renewable resources by 2020. The RPS, however, was repealed and replaced with a voluntary goal in May 2015.[337] The strong bipartisan legislative change was driven by falling support for renewables amongst policymakers. Specifically, proponents of the repeal identified increased rates and negative economic impact as a rationale for the change.[338]

Before the RPS became a voluntary goal, failure to comply with the renewable energy requirements would have resulted in a penalty equal to twice the market value of Renewable Energy Certificates ("RECs") that would have been necessary to meet the requirement. A utility was exempt from administrative penalties related to RPS noncompliance if it demonstrated that compliance causes a retail rate increase of 1% or more.

As it stands, a utility may meet the voluntary renewable energy goal by developing a portfolio of renewable energy capacity from generation, purchasing RECs, purchased energy, or net metering systems. Although grid-connected distributed generation may be counted towards the RPS goal, in 2014 Kansas legislators reduced the sizes of distributed facilities that are eligible for net

[337] Kansas Legislature. *House Substitute for Senate Bill No. 91.* Approved by Governor on May 28, 2015.

[338] Kansas Legislative Research Department. *Second Conference Committee Report Brief House Substitute for Senate Bill No. 91.* May 2015.

metering and limited net-metered connections to 1% of a utility's peak retail electricity demand during the previous year as part of a wider amendment of the net metering legislation.[339]

In addition to the voluntary RPS, Kansas has a property tax exemption in place for renewable energy. The property tax exemption was initially established for the life of property that is regularly used to generate electricity using renewable energy resources or technologies but is now only in effect if the facility filed an application for an exemption or received a conditional use permit on or before December 31, 2016. Facilities with applications filed after December 31, 2016, will be limited to ten years.[340] Additionally, state tax credits are available for projects that convert waste heat or biomass to energy.

Who is building renewable capacity in Kansas?

In general, renewables have developed independently of any policy framework in the State of Kansas. This is evidenced by the fact that the state had met its RPS target ahead of schedule before it became voluntary, and the capacity continues to grow, driven by market factors. The majority of projects currently in the interconnection queue in the SPP for Kansas are renewable; of the total 102 projects, 86 are for renewables, with 35 solar projects and 49 wind projects. Not all will be built, however.

Amongst the utilities required to report their renewable capacity to the Kansas Corporation Commission ("KCC"), Westar and Kansas City Power and Light Company ("KCP&L") have the greatest capacity coming online, with an additional 200 and 300 MW proposed between 2019-2020, respectively. Additionally, the IPP subsidiary of Southern Power Co. currently has a project under construction with a net capacity of 100 MW proposed to come online in December 2019.

An emerging trend in Kansas has been increasing corporate renewable procurement. One example is ENGIE North America's East Fork Wind Project, a 196 MW wind project expected to reach commercial operation in the spring of 2020. The project is underpinned by a long-term PPA to Brown-Forman, the corporate parent of Jack Daniel's Tennessee Whiskey, among other alcohol beverages. Other notable corporate purchasers of Kansas renewables include Google, a buyer of the 200 MW Cimarron Bend project, and Microsoft, owner of the 178 MW Bloom Wind project.

Sources: Commercial third-party database; S&P Global Market Intelligence. *Corporate Renewables in the United States.* March 31, 2019; ENGIE North America.

6.5.2 Energy efficiency

Kansas does not have an Energy Efficiency Resource Standard ("EERS"), and there are currently no requirements set for utilities in the state to offer customer energy efficiency programs. Instead, the KCC determined in 2008 that it would collaborate with utilities as they pursue energy

[339] Note that net metering is only available to IOUs. Under the Net Metering and Easy Connection Act, the IOUs are required to offer net metering and provide interested customers with bi-directional meters to implement the legislation. (Source: KCC website. *Net Metering in Kansas.* Accessed at: <https://kcc.ks.gov/electric/net-metering-in-kansas>)

[340] Ibid.

efficiency as a resource on a case-by-case basis. Following the publication of this policy by the KCC, the Kansas Energy Efficiency Investment Act ("KEEIA") was passed in 2014, providing the KCC with a mandate to approve proposals by electric and natural gas utilities for efficiency programs.[341]

Kansas utilities have demonstrated interest in implementing energy efficiency programs but have had limited uptake, and to date, no energy efficiency programs have been implemented under the KEEIA framework.[342] Before the KEEIA, the KCC had approved an energy efficiency surcharge recovered through an energy efficiency rider for the IOUs.[343] The Evergy utilities have implemented energy efficiency programs in the past through the energy efficiency rider, with limited uptake.[344] Most recently, KCP&L proposed a series of energy efficiency programs under the KEEIA, mirroring its existing programs in Missouri, but only seven of the fourteen proposals were approved. A more detailed review of the KCP&L proposals is considered in the textbox later in this section.

The evaluation of ratepayer-funded energy efficiency programs in Kansas relies on a series of regulatory orders that established formal rules and procedures,[345] which are directed by the KCC. Kansas uses four of the five classic benefit-cost tests identified in the California Standard Practice Manual ("CaSPM"). These are the Total Resource Cost ("TRC"), Utility/Programs Administrator ("UCT"), Participant ("PCT"), and the Ratepayer Impact Measure ("RIM"). While economic tests for energy efficiency are covered in greater detail later in this paper, we note that the KCC has historically placed greater emphasis on the TRC and RIM tests. A summary of the five classic tests is described in Figure 134.

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[341] Kansas Legislature. *Senate Substitute for HB 2482 – An Act creating the energy efficiency investment act.* Approved April 2014.

[342] KCC. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018*. December 2018.

[343] Ibid. P. 57.

[344] Ibid. P.56.

[345] Order in Docket No. 08-GIMX-442-GIV, Order in Docket No. 10-GIMX-013-GIV, and Order in 12-GIMX-337-GIV.

Figure 134. Summary of economic tests for economic efficiency

Economic test	Stakeholder perspective	Required by the KCC	Description
Participant Cost Test ("PCT")	Customer	Yes	This test evaluates the **costs and benefits from the perspective of the customer** installing the energy efficiency measure. Costs consist of the incremental costs of buying and installing the equipment, above the cost of standard equipment that is borne by the customer
Program Administrator Cost Test ("PAC")	Utility/ administrator	Yes	This test measures the **costs and benefits of the energy efficiency program from the perspective of implementing the program**. Overhead and incentive costs are included in the PACT costs. Savings derived from not delivering the energy to customers are the benefits from the utility's perspective
Ratepayer Impact Measure ("RIM")	Customer rates	Yes	This test evaluates the **costs and benefits of the programs on utility rates**. Costs considered under this approach consist of overhead and incentive payments and the cost of lost revenues due to reduced sales. The benefits include in the RIM are the avoided costs of energy saved through the efficiency measures
Total Resource Cost ("TRC") test	Regional	Yes	This test measures the **net benefits of the energy efficiency program for the region as a whole**. Benefits included the avoided cost of energy while costs included are the purchase and installation costs as well as overhead costs of running the energy efficiency program
Societal Cost Test ("SCT")	Society	No	This test measures the **environmental and other non-energy benefits** that are not presently valued by the market, over and above those measures by the TRC. Emissions costs may also be included in the market price used to determine avoided costs

Sources: ACEEE; National Action Plan for Energy Efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* 2008

Under the KEEIA, benefit-cost tests are required for total program and customer project level screening, but exceptions are made for low-income programs, pilots, and new technologies. Economic incentives for energy efficiency measures in Kansas are limited, although the KCC allows for a rate-of-return of 0.5% to 2% of authorized capital investments specifically for energy efficiency investments.

Previous regulator energy efficiency assessments in Kansas

In 2016, KCP&L proposed a demand-side management program, which included 14 energy efficiency programs similar to ones the utility had already implemented in Missouri. KCP&L recommended its portfolio of programs based primarily on the Total Resource Cost ("TRC") test but Kansas regulators approved only seven of the 14 programs, rejecting the other seven on the grounds that they did not meet the standards for cost effectiveness.

KCC staff asserted that commission policy required that efficiency proposals be accompanied by TRC, Ratepayer Impact Measure ("RIM"), Program Administrator Cost ("PAC") and Participants tests. Commission staff also noted that they utilized a three-stage evaluation approach to assess the cost-effectiveness as follows:

- First it **reviews** the utility's **benefit-cost test results**. Should the TRC be above one, it would proceed to stage two;
- In the second stage, staff ask the utility to conduct a **sensitivity analyses of its test results**, specifically of the avoided capacity cost and net-to-gross ratio ("NTG") variables. If the TRC fell below one, or the RIM fell below 0.7, it would conclude the program is unlikely to be cost effective; and
- In the third stage, the staff **evaluated the risk** of the effect of a **low RIM** against other positive aspects of a proposed program.

The Commission's decision was based on their evaluation that the rebates and other benefits of the proposed portfolio did not justify their cost, and in part because of its assessment of the proper way to calculate the quantity of expenses the utility could avoid through reduced electricity sales. The Commission noted that while it still requires the four tests noted above, it will continue to place an emphasis on the TRC and RIM tests.

Sources: KCC. *Final Order. Application of Kansas City Power & Light Company for Approval of Demand-Side Management Program Portfolio and Recovery Mechanism.* Docket No. 16-KCPE-446-TAR. April 2016.

More broadly, Kansas consistently ranks among the bottom states on the amount of energy efficiency programs and incentives compared to other US states. The American Council for an Energy-Efficient Economy ("ACEEE") publishes an annual scorecard for energy efficiency, where it ranks US states and their available programs according to six main categories including utility programs, transportation, building energy codes, combined heat and power, state initiatives, and appliance standards.[346] Figure 135 below shows Kansas's overall ranking, showing it ranks in the bottom quartile, with neighboring Great Plains states also ranking low.

[346] ACEEE. *2019 State Energy Efficiency Scorecard*. October 1, 2019.

Figure 135. Kansas relative rank in energy efficiency measures

Source: ACEEE. *2019 State Energy Efficiency Scorecard.* October 1, 2019.

Similarly, Kansas can be considered an energy-intensive state, ranking among the top 20 states in both energy consumption per capita, and electricity consumption per capita, at 16th in both respectively.[347,348]

In subsequent sections, LEI discussed the impact of additional renewables, energy efficiency, and additional considerations for evaluating alternative energy programs. LEI also briefly described the experience of neighboring states, identifying best practices from these states that might be considered for Kansas.

6.5.3 Would additional renewables or energy efficiency help bring rates down in Kansas?

6.5.3.1 Conceptual framework

Kansas policymakers and regulators are concerned about rising rates and rate competitiveness in the State, and it is through this lens that we have considered the potential for renewables and energy efficiency to reduce rates. To assess this, we are analyzing the wholesale drivers in SPP, as well as looking at what cost-benefit frameworks might best achieve this goal.

In the following sections, LEI considered a wholesale market price modeling methodology to estimate the impact of the increased penetration of renewables on the electricity rates, as well as discussed, at a high level, the role of economic tests for energy efficiency.

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[347] EIA. *Table C13. Energy Consumption Estimates per Capita by End-Use Sector, Ranked by State, 2017.* 2019

[348] California Energy Commission. *Almanac: U.S. Per Capita Electricity Use By State.* 2018.

6.5.3.2 Market price modeling methodology

The SPP operates an energy-only market covering part or all of 14 states from as far south as Texas, spanning northwards to North Dakota. In March 2014, SPP moved from a real-time energy market towards an 'integrated marketplace', a more comprehensive day-ahead and real-time energy market design. With the transition to the SPP Integrated Market ("SPPIM" or "IM"), SPP runs a centralized co-optimized day-ahead and ancillary services energy market.

LEI's modeling involves a spot market price forecast that assumes efficient, least-cost dispatch. Least-cost dispatch, already accommodated by the previous real-time market, is further enhanced through the day-ahead market design. SPP combined its 16 legacy Balancing Authorities ("BA") into one entity and now acts as the Consolidated Balancing Authority ("CBA") for the entire market footprint, which has been in effect since March 2014.

To perform forecasts over the period up to 2029, LEI relied on the firm's proprietary network simulation model, POOLMod, which is described in Section 14 (Appendix E: Overview of forecasting methodology). Explicit forecasts rely on inputs derived from publicly available information, commercial databases, and LEI's market knowledge. Key input assumptions to this modeling are covered in more detail in Section 13 (Appendix D: SPP modeling assumptions) and include forecasted fuel prices and generic new entry. LEI notes that this analysis is illustrative, and multiple cases would need to be explored before coming to a conclusion.

For this project, LEI has performed a long-term forecast of the SPP market, evaluating two cases as follows:

- **Base case**: status quo long-term forecast; and
- **High renewables case**: additional renewables new build entailing 10% of the SPP interconnection queue for Kansas.[349,350]

The results of each scenario are discussed below.

LEI's forecasted market prices for the KSMO zone from 2020 to 2039 are represented below for both peak and all hours. Energy prices over the outlook horizon increase at a CAGR of 6.5%, driven by increased gas prices, thermal retirements in later years, and increased intermittency as additional renewable generation is added into the system. This is illustrated in Figure 136 below.

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[349] SPP interconnection queue data is sourced from a commercial third-party database.

[350] SPP CEO Nick Brown noted that in practice, "only a fraction of the interconnection queue is built." Looking at other RTOs/ISOs, LEI noted that in PJM, as of 2018, only 11% of all requested projects have gone into service since the inception of the queue. Therefore, for the high renewable case, LEI assumed additional renewables new build at 10% of SPP's interconnection queue. (Source: SP Global. *Southwest Power Pool board approves $336 million to expand grid as wind growth draws fire*. October 2019; PJM. *2018 State of the Market).*

Figure 136. Forecast energy market peak and all-hour prices in the Kansas zone (2020-2029)

For the high renewables case, LEI has added 10% of the SPP renewable interconnection queue that is identified for build-in Kansas over the 2024-2029 period i.e. starting from the last year in which plants under construction are expected to come online. In this period, LEI has added ~2 GW of additional wind generation, corresponding to an annual average addition of 400 MW. When compared to the base case, prices decrease by 1.2% on average over the forecast horizon. This is illustrated in Figure 137 below.

Figure 137. Forecast energy market base case and high renewables case prices in the Kansas zone (2020-2029)

Modeling results indicate that status quo market drivers, such as gas prices and additional renewables, will cause a gradual increase in wholesale prices in the SPP region. The additional new entry of wind capacity in the later years of the model suggest that a decrease in wholesale prices of more than 1% can be achieved. This does not mean 1% of bills because of wires charges and the costs of existing plants that remain on the system.

In practice, however, as discussed in the previous rate study by the KCC, declining wholesale prices are only effective to the extent that the utilities can reduce their corresponding net production expenses.[351] The utilities also noted that falling wholesale prices had reduced their energy sales opportunities in the SPP market,[352] suggesting that this decline will have a limited impact on customer bills.

6.5.3.3 Assessing the benefits and costs of energy efficiency programs

Multiple energy efficiency programs have been established and studied across multiple jurisdictions in the US for the past decade. Literature from academia and industry have quantified their findings with respect to reduction of load and costs for customers and utilities.[353] In 2018, electric efficiency programs in the US resulted in savings of 27 million MWh, or 0.73% of total retail sales.[354] With respect to consumer savings, in 2015, efficiency standards were estimated to save the average US household around $500 on utility bills, or 16% of total household bills.[355,356]

In general, regulators will assess the cost-effectiveness of energy efficiency programs from the perspective of the various stakeholders, e.g., the customers (or participants), the utilities (or administrators) or the entire region. LEI understands that KCC has considered these issues before. Specifically, the regulator established a regulatory docket in 2008 to study the costs and benefits of energy efficiency programs, establishing its policy that a program which has passed the TRC test, and RIM test, PAC and Participants tests (which are described in Section 6.5.2) to determine that the energy efficiency rider is appropriate.[357] LEI also notes that the KEEIA

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[351] Net production expense is defined by the KCC as Total Power Production Expense (inclusive of Fuel, Purchased Power, Other Power Production Expenses), less Sales for Resale, i.e. the cost of power production for the utility. (Source: Kansas Corporation Commission. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018.* December 2018).

[352] Westar Energy & Kansas City Power & Light Co. *Kansas Rate Study. Exhibit A. Docket No. 19-KCPE-053-CPL.* January 2019. PDF P. 30.

[353] Hoffman, I., et al. *The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009–2015.* Berkeley Lab. June 2018. Accessed at: <emp.lbl.gov/publications/cost-saving-electricity-through.>

[354] ACEEE. *The 2019 Energy Efficiency Scorecard.* October 2019.

[355] Nadel, S. et al. *Energy Efficiency in the United States: 35 Years and Counting.* ACEEE. June 2015.

[356] deLaski, A. & Mauer, J. *Energy-Saving States of America: How Every State Benefits from National Appliance Standards.* February 2017.

[357] KCC. *Final Order. In the Matter of a General Investigation Regarding Cost Recovery and Incentives For Energy Efficiency Programs.* Docket No. 08-GIMX-441-GIV. November 2008.

legislation specifically states that, with the exception of programs targeting low-income customers or general education programs, "*programs determined to be non-cost-effective…shall be modified to address deficiencies or terminated following such determination.*"[358]

However, best practices observed in neighboring states suggest that cost-effectiveness tests for energy efficiency programs might understate the benefits of energy efficiency. Benefits that are typically not considered as part of these tests include reliability, health, and economic development benefits, as they are considered harder to quantify.[359] Other quantifiable metrics that are often excluded include the impact of efficiency resources in reducing wholesale prices i.e. wholesale price suppression.[360]

Recognizing these limitations of the traditional tests, the National Efficiency Screening Project ("NESP") has developed a manual referred to as the National Standard Practice Manual ("NSPM") that encourages regulators to develop a jurisdiction-specific resource value test ("RVT"). Under the framework of an RVT, the traditional tests are still considered, as well as aiming to capture the jurisdiction's relevant policy goals.[361] In Arkansas, this framework has been implemented in the evaluation of energy efficiency programs, whereby the regulator is specifically working to quantify carbon costs, as well as properly accounting for the non-energy impacts in its assessment.[362,363]

According to a database that tracks US states that are applying these additional principles to screening tests, there are ten states that are either in the process of learning about the NSPM, are actively applying the framework, or have a PUC order on the NSPM or RVT.[364] In addition, in 31 states, including Kansas, the framework has either been referenced in regulatory proceedings or the legislature, suggesting there is broad recognition to refine the review and implementation of energy efficiency evaluation.[365]

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[358] Kansas Legislature. *Senate Substitute for HB 2482 – An Act creating the energy efficiency investment act.* Approved April 2014.

[359] ACEEE. *A New Tool to Improve Energy Efficiency Practices: The Database of State Efficiency Screening Practices (DSESP).* July 2019.

[360] Ibid. P. 4.

[361] Ibid. P. 8.

[362] Ibid. P. 9.

[363] NESP. *National Standard Practice Manual Case Study: Arkansas' Current Practices.* Prepared for the Arkansas Public Service Commission. October 10, 2018.

[364] ACEEE. *A New Tool to Improve Energy Efficiency Practices: The Database of State Efficiency Screening Practices (DSESP).* July 2019.

[365] Ibid. P. 9.

An illustrative framework for considering energy efficiency programs may be informed not only by the outcomes of the cost-effectiveness tests but a broader consideration of the benefits that are not captured under the CaSPM framework tests. This framework is summarized in Figure 138 below.

Furthermore, this framework might be linked to a potential IRP process, whereby energy efficiency is considered as a potential resource for consideration by utilities in least-cost planning. Examples of the practical implications of this framework can be seen from the experience of three selected neighboring states. These are discussed in the textbox below and highlight some of the issues that Kansas policymakers might consider.

Figure 138. Illustrative energy efficiency evaluation framework for Kansas

Energy efficiency programs and evaluation practices in other states

Recent moves by Kansas' neighboring states to either increase efficiency targets, review their efficiency evaluation practices, or implement efficiency incentives are worthwhile for consideration. We consider the experience of Arkansas, Oklahoma and Missouri in their approaches to implementation.

In **Arkansas,** a state-mandated EERS has been in place since 2010. However, in 2018 the regulator, the Arkansas Public Service Commission ("APSC") updated the efficiency targets to 1.2% of 2018 baseline sales for electric utilities, and 0.5% of baseline sales for natural gas utilities following a regulatory proceeding. In meeting this target, the utilities are awarded an incentive of 10% of portfolio total resource cost net benefits for achievement ranging between 80% and 120% of the Commission-established performance goal. In reviewing proposed efficiency programs, the APSC relies on the TRC test, but also considers "*non-energy costs and benefits associated with water savings, other fuels, participants' equipment replacement costs, participant measure costs, and additional non-energy benefits (NEBs) for low-income customers*."

In **Oklahoma,** all electric utilities under rate regulation by the Oklahoma Corporation Commission must propose, at least once every three years, a portfolio of energy efficiency and demand-response programs within their service territories. Utilities are eligible to recover lost revenues from their energy efficiency programs through the Lost Revenue Adjustment Mechanism, and receive a shared savings-based performance incentive for successfully implementing a demand reduction portfolio. Specifically, the IOUs must achieve at least 85% of goals to gain this incentive and is capped at 15% of total program cost. Currently, Oklahoma Gas & Electric and Public Service Oklahoma have proposed and implemented demand reduction portfolios.

In **Missouri,** energy efficiency is driven by the Missouri Energy Efficiency Investment Act, which requires utilities to capture all cost-effective energy efficiency opportunities. In its evaluation of efficiency programs, Missouri primarily relies on the TRC test, but it allows for benefits such as increased property values, reduced operations and maintenance costs, and decreased water and sewage bills. Finally, Missouri established a voluntary energy efficiency target, defined as a cumulative annual savings of 9.9% by 2020 (from 2012).

Sources: ACEEE. *The 2019 Energy Efficiency Scorecard.* October 2019; DSIRE; NESP. *The Database of State Efficiency Screening Practices.* October 2019.

6.5.4 Potential avenues for Kansas to explore

In this section, we consider the potential actions that can be taken with respect to renewables and energy efficiency in Kansas.

6.5.4.1 Renewables: no further action needed

A combination of falling renewables prices and favorable renewables resource suggests that no additional state-mandated incentives are needed to drive increased penetration of renewables. Despite the gradual sunset of federal incentive programs such as the production tax credit ("PTC"),[366] it is expected that the drivers for renewable energy will sustain their continued build-out. Results of the wholesale modeling suggest that additional renewables will continue to drive down wholesale prices in SPP and is consistent with market drivers that are understood. As discussed in Section 6.7 of this report, actions taken by SPP to review their transmission cost allocation mechanism will spur additional investment by utilities that may have been held back by transmission costs.

In addition to this, policymakers should consider whether the goals of the programs would be achieved regardless of policy intervention, i.e. would market drivers lead to similar outcomes of the proposed program. For instance, an evaluation of the Kansas RPS target in 2014 by the KCC found that while renewables comprised only 2.2% of utility revenue requirement, they were supplying around 15% of peak demand in the state.[367]

Additional programs may consider support for behind-the-meter generation as an incentive to reduce utility bills. However, such programs are beyond the scope of this paper and should be viewed in the context of a holistic review of distributed generation in the state.

6.5.4.2 Energy efficiency: additional options to consider

With the Kansas Energy Efficiency Investment Act ("KEEIA"), a framework was created by utilities regulated by the KCC to implement additional energy efficiency measures. However, it

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[366] The Renewable Energy Production Tax Credit will be phased down by end of 2019. (Source: Database of State Incentives for Renewables & Efficiency ("DSIRE") website. *Renewable Electricity Production Tax Credit (PTC).* Last Updated February 28, 2018. Accessed on December 16 2019.

[367] KCC. *Retail Rate Impact Report.* 2014. Accessed at: <https://kcc.ks.gov/pi/2014_retail_rate_impact_report.pdf>

appears that this framework may need additional refinement. Given the cost-saving potential of energy efficiency, as cited above, it appears that strategic, targeted and cost-effective energy efficiency programs could help Kansas customers reduce their energy bills, helping to address the underlying challenge of high rates in Kansas.

As a result, we would recommend that the KCC conduct a more detailed study on what the energy efficiency potential in Kansas is (both how much in total and in which customer segments specifically). The results of this study could be used to set a voluntary target for IOUs and could also help provide information about useful program design to co-ops as well. We would also recommend that the KCC reassess its assessment of energy efficiency programs to reflect more updated best practices to include a broader array of benefits. We also recommend that the KCC consider more proactively encouraging the IOUs to submit proposals for decoupling, given the cost benefits that can result. However, our primary recommendation is for energy efficiency programs to be considered holistically as part of an IRP process.

6.5.4.2.1 Voluntary energy efficiency goals

In Kansas, there is no mandated energy efficiency target. However, a voluntary goal that is in line with neighboring states such as Missouri, coupled with a program portfolio designed for a targeted set of customers, may be feasible and consistent with Kansas goals. A voluntary goal for energy efficiency might mirror the existing voluntary renewable goal, with utilities provided with a framework on how to meet the targets, without compelling them to do so. In Missouri, utilities have a voluntary efficiency goal of cumulative annual energy savings of 9.9% from 2012 to 2020.[368] Utilities might also be encouraged to initiate efficiency programs consistent with the existing KEEIA law.

6.5.4.2.2 Revised energy efficiency assessment approaches

Under the described National Standard Practice Manual ("NSPM") for screening energy efficiency programs, a framework for estimating the range of utility and non-utility energy efficiency system impacts can be identified. A broader discussion on implementing a Kansas-specific screening mechanism that incorporates existing KCC policy, broader Kansas policy objectives, as well as regional best practice measures that have been proven to be effective will be useful. Considerations might include reliability benefits and other non-energy impacts such as health and economic development benefits that are considered more difficult to quantify. While evaluation of the existing efficiency assessment framework is beyond the scope of this paper, an analysis of existing practice through the lens of regional best practice would be a positive next step.

6.5.4.2.3 Targeted programs that reduce customer bills

Based on our understanding of the Kansas electricity market, LEI believes that programs that reduce peak demand, support lower-income households and minimize the impact of space-

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[368] Missouri Rules of Department of Economic Development. *4 CSR 240-20.092 Definitions for Demand Side Programs and Demand-Side Programs Investment Mechanisms.* Last updated in 2018.

heating customers in Kansas could be cost-effective programs. This is consistent with previous KCC recommendations in its Final Order following an investigation regarding energy efficiency programs, where the Commission stated it would consider performance incentives for programs that "target low and fixed income customers, and renters" and that "target new and existing residential housing and demonstrate a potential for long-term savings."[369] An example of a program design that meets stated policy objectives has limited non-participant costs and targets bill reduction is described in the textbox below.

Xcel Energy's low-income program in Colorado

In Colorado, Xcel Energy Low-Income Program has provided weatherization services for low-income customers since 2009. The services offered include free energy assessments, identification of custom and prescriptive rebates, procurement, installation, contracting, project management, and behavior-change education. Specifically, the program provides gas and electric energy efficiency measures including "*HVAC upgrades, insulation, air sealing, storm windows, showerheads, aerators, programmable thermostats, refrigerator replacement, electrically commutated motors, LEDs, and evaporative coolers.*"

The program is delivered through Energy Outreach Colorado ("EOC"), a nonprofit organization, and the utility is responsible for engineering analysis and determining cost-effectiveness as well as approving rebates. Since inception, the program has served 38,000 households, saved over 45 GWh and realized $73 million in bill savings. Further, in 2017, the program reduced nearly 1 MW in peak demand.

Sources: ACEEE. *The New Leaders of the Pack: ACEEE's Fourth National Review of Exemplary Energy Efficiency Programs.* January 2019; Xcel Energy.

6.5.4.2.4 Revenue decoupling

Decoupling is a revenue adjustment mechanism that is intended to provide substantial risk-mitigation benefits for both utilities and consumers by essentially decoupling sales from revenues, allowing utilities to become financially indifferent to the quantity of energy they sell. While decoupling mechanisms are uniform in their general definition and objective, there is substantial variation in their design and application. The design process of a decoupling mechanism involves a series of decision points that will vary based on policy and stakeholder priorities. One standard method involves setting rates according to a permitted revenue per customer, rather than setting rates by units sold. With this technique, the regulator sets an allowed revenue per customer and then implements price adjustments according to whether the utility sold more or less energy than expected.

Evaluations of energy efficiency policies have highlighted the positive effects decoupling mechanisms have had for utilities in the United States. Using twelve years of energy policy data

[369] KCC. *Final Order. In the Matter of a General Investigation Regarding Cost Recovery and Incentives For Energy Efficiency Programs.* Docket No. 08-GIMX-441-GIV. November 2008.

for privately owned utilities from 2004 through 2015, a recent study showed that utilities with decoupling mechanisms in place are associated with 3.9% lower residential electricity consumption per customer.[370] Additionally, the study found that when decoupling is combined with Energy Efficiency Resource Standards ("EERS"), the two policies together are, on average, associated with 9.7% lower residential electricity consumption per customer.[371] The study noted that decoupling on its own is associated with lower rates, as decoupling results in reduced costs and reduced cost of capital for the utility is passed on to customers.[372]

In Kansas, the KCC policy is based on the 2008 investigation into energy efficiency, where it stated that it would consider decoupling proposals on a case-by-case basis.[373] As of 2019, no decoupling proposals have been approved for any utilities, and it remains an area of opportunity for Kansas utilities.[374]

Key takeaways

Renewables in Kansas comprise primarily of wind capacity, has been driven by the presence of exceptional wind resource, falling capital costs, favorable federal policies and availability of transmission. Energy efficiency, however, has lagged behind, with few efficiency programs implemented, and no energy efficiency resource standard ("EERS").

- No additional state-mandated incentives are needed to drive increased penetration of renewables. It is expected that the drivers for renewable energy will sustain their continued build-out.
- More opportunities exist in energy efficiency, and strategic, targeted and cost-effective energy efficiency programs could help Kansas customers reduce their energy bills. Efforts to study energy efficiency potential in the state coupled with a move to revise the current energy efficiency review approaches, and encouraging utilities to submit more proposals, may realize additional benefits in the future. However, incorporation into IRP processes would be the best approach.

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[370] Theel, Shauna. *Moving Toward Energy Efficiency*. Oracle Utilities. Harvard University, 2017

[371] Ibid.

[372] Ibid. P. 57.

[373] KCC. *Final Order. In the Matter of a General Investigation Regarding Cost Recovery and Incentives For Energy Efficiency Programs.* Docket No. 08-GIMX-441-GIV. November 2008.

[374] National Conference on State Legislatures. *State Policies for Utility Investment in Energy Efficiency.* April 2019.

6.6 Securitized ratepayer-backed bonds

Securitized ratepayer-back bonds are financial assets created for the purpose of lowering utility rates by financing part of the utility's rate base using a lower cost of capital financial and legal structures. The process for a state to create securitized ratepayer-backed bonds, or a securitization is a well-known form of addressing stranded costs in the US. It has been used to recover stranded costs (or other extraordinary costs) associated with the liberalization of electricity markets, construction cost of environmental control equipment, and more recently, paying for storm recovery costs.

Generally, securitization involves the following steps:

- The state legislature passes a law that authorizes the use of securitization by utilities, which covers the ability to enforce non-bypassable tariffs onto consumers, authorizes the regulator to issue irrevocable finance orders, defines the types of activities/assets for which the regulator is allowed to issue the finance order, identifies the legal and tax status of the legal entity housing the ratepayer-backed bond, and sets the standards of review for the PUC to issue the finance order.
- Once the asset (or in some cases a specific funding requirement, such as disaster relief) to be securitized has been identified and the cost-benefit analysis of securitization has been studied, the regulator issues a financing order allowing the creation of the ratepayer-backed bond to raise a specific dollar amount, and specifying the dollar amount (minus any fees) to be removed from the rate base of the regulated utility.
- A special purpose vehicle ("SPV"), which is a legal entity created just for the securitization, is created to house the ratepayer-backed bond.
- Investment banks market the bond to investors.
- The funds raised are paid to the regulated utility to recover the costs associated with the securitized asset or funding requirement.

Securitization aims to lower rates by reducing credit risk

Securitization aims to achieve lower rates to ratepayers by minimizing the cost of capital for the securitized portion of the rate base. The cost of capital of the securitized rate base could be materially lower than the cost of capital of a regulated utility because:

- **No cost of equity** – the SPV has no equity holders and thus there is no equity return required, leading to lower cost of capital;
- **No income tax payments** – since the SPV is a pure financing entity, all revenue would be either used for amortization of debt or payment of interest, meaning there would be no pre-tax profit on which to assess income tax;
- **Adjustment mechanism resulting in lower default risk** – the special tariff charged to ratepayers to repay the SPV's bonds are adjusted through an automatic mechanism that is separate from the general rate case. This lowers the SPV's regulatory risk and allows

rates to be readjusted more frequently in response to changes in demand levels or other parameters affecting repayment;

- **Non-bypassable rates –** the state legislation would generally require the repayment rate for the SPV bonds to be non-bypassable by ratepayers unless the ratepayer completely disconnects from the grid. In most cases, ratepayers would still have to pay the special tariff related to SPV bond payments even if they decide to self-generate. As long as entities are still connected to the utility's network, they would still be required to make SPV bond payments at a rate determined by their consumption level prior to self-generation. This arrangement reduces demand change risk of the SPV;
- **Isolated from bankruptcy risk of the regulated utility –** the state legislature would generally specify that the financing order would remain in effect even if the regulated utility goes out of business or is succeeded by another utility. This arrangement, therefore, isolates the SPV from the credit risk of the regulated utility;
- **Isolated from performance and O&M risk of the underlying asset –** as explained later in this section, the repayment of the SPV's bond is not related to the performance of the asset that is used to value the securitization process. The SPV is also not responsible for any operations and maintenance cost of the underlying asset going forward, and is therefore isolated from the risk of high O&M cost;
- **The SPV is specifically structured to obtain the highest possible credit rating –** since the purpose of securitization is to lower ratepayer costs through low-cost financing using an SPV, the SPV is tailored to meet the criteria necessary to obtain the highest credit rating possible. This includes having strict articles of association, financial control standards, and restrictions on allowed activities.

Due to these characteristics of the SPVs, ratepayer-backed bonds can secure very high credit ratings and achieve low financing costs.[375]

There are a few additional considerations for ratepayer-backed bonds. First, unlike securitized mortgage bonds (real estate mortgages that are securitized and sold to investors), the ownership of the assets identified during the securitization process for ratepayer-backed bonds do not necessarily get transferred or pledged to the SPV,[376] even though it is sometimes referred to as the "securitization of stranded assets" or "securitization of environmental control equipment." What is being securitized is simply a stream of payments. This means that the security bondholders do not actually have claims to the assets in case of a default event. Instead, the reference to the assets is only used to calculate the monetary amount of the SPV and the corresponding amount to be removed from the regulated utility's regulated asset base.

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[375] LEI's research indicates that except for one instance, all ratepayer-backed bonds issued in the US related to electric utilities have achieved and maintained AAA credit ratings from credit rating agencies.

[376] SB 198 Section 3(11)(D)(c) states that "A financing order ***shall allow and may require*** the creation of an electric utility's K-EBRA property to be conditioned upon the sale or other transfer of the K-EBRA property to an assignee and the pledge of the KEBRA property to secure K-EBRA bonds." [Emphasis by LEI]

Second, although the "securitized" asset is removed from the utility's rate base, it can still cause regular expenses for the regulated utility depending on the nature of the asset. This can lead to on-going rate impact. For example, environmental control equipment funded by ratepayer-backed bonds requires continued opex and maintenance capex. Should future events result in significant capex requirements on such equipment, the ratepayers will still have to pay for this capex. In other words, the securitization process does not offload the risks of the asset from the ratepayers or the regulated utility to the SPV bondholders.[377]

Figure 139 below illustrates the major components of rates charged to ratepayers before and after securitization. In this illustration, a portion of a regulated utility's rate base is securitized, corresponding to the nominal value of the bonds issued by the SPV. The overall rates paid by ratepayers would decrease as the financing cost of the SPV is lower than the WACC of the regulated utility.

Figure 139. Illustration of the annual cost before and after securitization

Extending the repayment terms may also reduce rates

On top of lowering financing cost of a rate base asset by enhancing the credit, securitization can also help lower rates in the present by extending the repayment period. For example, if an asset in a utility rate base has a remaining economic life of five years, the asset value would be depreciated over that time, and the return on (WACC) and return of investment (depreciation) of

[377] This is different from mortgage-backed securities, where the lending bank offloads the risk of the mortgage to the bondholders.

this asset would be charged to ratepayers over the next five years. If the same asset is instead securitized into ratepayer-backed bonds with a ten-year maturity, and the value of this asset is removed from the rate base of the regulated utility, the asset's burden to ratepayers over the next five years would be reduced. However, the ultimate total burden onto ratepayers over the ten-year period could be higher, depending on the difference between the regulated utility's approved WACC and the interest rate of the ratepayer-backed bond.

Figure 140 presents a numerical example where a $100 asset is in one scenario depreciated over a five-year period with the regulated utility earning an 8% WACC, and in the alternative scenario is instead securitized through a 5% interest rate ten-year maturity ratepayer-backed bond. In this example, the immediate rate burden over the next five years is reduced by an average of $11.85 under the "with securitization" scenario, although the total payment over the 10-year period is $5.5 higher.

Figure 140. Example of annual rate impact of securitization (5% interest rate)

Asusmptions	
Approved utility WACC	8%
Asset value	100
Asset economic life	5 years
SPV interest rate	5%
SPV maturity	10 years

No Securitization

Year	1	2	3	4	5	6	7	8	9	10	Total
Asset starting value	100.0	80.0	60.0	40.0	20.0	-	-	-	-	-	
Depreciation	20.0	20.0	20.0	20.0	20.0	-	-	-	-	-	
Asset ending value	80.0	60.0	40.0	20.0	-	-	-	-	-	-	
Return on asset	8.0	6.4	4.8	3.2	1.6	-	-	-	-	-	
Ratepayer burden	**28.0**	**26.4**	**24.8**	**23.2**	**21.6**	**-**	**-**	**-**	**-**	**-**	**124.0**

With securitization

Year	1	2	3	4	5	6	7	8	9	10	Total
Bond value	100.0	92.0	83.7	74.9	65.7	56.1	45.9	35.3	24.1	12.3	
Interest	5.0	4.6	4.2	3.7	3.3	2.8	2.3	1.8	1.2	0.6	
Principal repayment	8.0	8.3	8.8	9.2	9.7	10.1	10.7	11.2	11.7	12.3	
Ratepayer burden	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**13.0**	**129.5**

Note: For simplicity, both return on asset and interest on debt are based on opening value of the asset during the year
Also, we assume straight-line deprecation of the asset and simple amortization of the ratepayer-backed bond

If the interest rate on the ratepayer-backed bond is 4% instead of 5%, the 10-year total cost would decrease to $123.3, resulting in both lower near-term ratepayer burden and lower total ratepayer burden.

6.6.1 Securitization is a risk and time reallocation process

Fundamentally, there is no "magic" in the electric utilities securitization process or ratepayer-backed bonds. The securitization process is, in essence, a risk and time reallocation process, achieved by deliberately carving out a part of the rate base and packaging it with higher credit legal arrangements, possibly amortized over a longer period of time. Therefore, there are tradeoffs that regulators, electric utilities, and ratepayers should consider before committing to securitization:

- **Amortization period, trading lower rates for higher overall payments over time** – as presented in the example in Figure 140, if the interest rate of the ratepayer-backed bond is not low enough, the securitization process would become a tradeoff as a longer repayment term would lower rates in the short term, but ultimately result in higher costs over time. This outcome could create a fairness issue as future ratepayers who may have never benefited from the securitized asset would have to bear the cost of financing the asset.
- **Regulators would have less control over rates once securitization happens** – in order to secure high credit rating for the ratepayer-backed bonds, regulators would give up control over securitized costs by putting an irrevocable finance order with an automatic adjustment mechanism in force. This means regulators could not influence that portion of the rates though measures such as changing approved WACC or delaying rate cases to suppress rates.
- **The cost of replacing services provided by the securitized asset must be taken into account** – Should the securitized asset be retired, the cost of procuring replacement services (such as energy or capacity provided by a generation asset prior to its retirement) must be taken into account. These costs may, however, be offset by the decrease in operating and maintenance costs of the retired asset. As such, the ultimate cost/benefit analysis of securitization must be performed holistically, taking into account all cost impacts to ratepayers.

6.6.2 Case studies of securitized ratepayer-backed bonds

In this section, LEI provides three case studies of securitization in the US that cover different types of underlying assets. The case studies include discussion of the legal and regulatory process before the securitization, the size of the ratepayer-backed bonds, the credit protection of the SPV, and the estimated ratepayer savings.

6.6.2.1 Allegheny Energy (West Virginia, 2007)

In April 2007, two subsidiaries of Allegheny Energy, Potomac Power, and Monongahela Power issued $114.8 million and $344.5 million (totaling $459.3 million) of securitized ratepayer-backed bonds, respectively, to fund planned environmental upgrades. The bonds were issued to finance the construction of newly mandated pollution control equipment (scrubbers) at Monongahela's 1.1 GW coal-fired Fort Martin Power Station near Morgantown, West Virginia, to enable the continued use of local, high sulfur coal at the plant. Securitization was used to deliver the lowest possible cost to ratepayers while simultaneously maintaining plant operations, keeping local miners at work, and meeting required pollution reduction targets.[378]

The West Virginia Public Service Commission ("WVPSC") approved the agreement between Monongahela and Potomac Edison following the 2005 state legislation that enabled the use of securitization financing for the construction of pollution control equipment at public utilities. The

[378] Saber Partners, LLC. "Public Service Commission of West Virginia (PSC) Projects $130 Million in Savings For Ratepayers Through Innovative Bond Sale." https://saberpartners.com/press/public-service-commission-of-west-virginia-psc-projects-130-million-in-savings-for-ratepayers-through-innovative-bond-sale/, April 2007.

WVPSC issued an irrevocable financing order in 2006, granting the SPVs of Monongahela and Potomac Edison, MP Environmental Funding LLC and PE Environmental Funding LLC respectively, the right to secure up to $338 million in project costs through Senior Secured Sinking Fund Environmental Control Bonds, Series A ("environmental control bonds").[379] This amount was later raised to $450 million in construction costs plus an additional $16.5 million in upfront financing costs following a petition settlement later that year.[380]

The bonds were modeled off stranded cost securitizations seen in deregulated power markets and ultimately received a AAA rating.[381] The WVPSC approved the bonds in January 2007,[382] and securitization was completed by April 2007 with the sale of $459.3 million in environmental control bonds.[383] The bonds were issued in several tranches with maturities of 4, 10, 16, and 20 years with interest rates of 4.98%, 5.23%, 5.46%, and 5.52% respectively.[384] Net proceeds from bond sales were restricted towards the purchase and installation of the scrubbers.

At the conclusion of bond sales, the WVPSC predicted that securitization would save ratepayers over $130 million (in real dollar terms) over the life of the bonds (4-20 years) as compared to traditional financing methods.[385]

While ratepayer-backed bonds have previously been issued to recover stranded costs associated with deregulated markets, this case is considered to be the first example of using securitization for environmental upgrades. It shows that securitization can act as a useful tool for utilities in states dependent on coal generation. However, only some states permit the use of securitization for environmental upgrades.

6.6.2.2 Entergy Louisiana (Louisiana, 2011)

In 2007, the Louisiana Public Service Commission ("LPSC") approved Entergy Louisiana, LLC's ("ELL") $1.76 billion plan to convert their 538 MW Little Gypsy natural gas-fired peaking unit to

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[379] United States Securities and Exchange Commission. *Form 10-K.* https://www.sec.gov/Archives/edgar/data/3673/000119312510044488/d10k.htm, March 2010.

[380] Ibid.

[381] Moody's Investors Service. "$115 million of Senior Secured Sinking Fund Environmental Control Bonds Rates." https://www.moodys.com/research/Moodys-Rates-Allegheny-Energys-Environmental-Control-Bonds-P-Aaa--PR_130966, April 2007.

[382] Saber Partners. "Allegheny closes pollution control issue." April 2007.

[383] United States Securities and Exchange Commission. *Form 10-K.* March 2010.

[384] Saber Partners, LLC. "Allegheny closes pollution control issue." April 2007.

[385] NRRI. "Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update." https://pubs.naruc.org/pub/9F840749-E221-0519-1AE3-164C61AD7157, January 2019.

petroleum coke and coal-fired plant.[386] The Little Gypsy repowering project was an attempt to diversify ELL's fuel requirements by converting the plant to a solid-fuel unit.[387] In 2009, ELL determined that the plant was no longer economically viable due to a weak economy, low natural gas prices, and potential federal emissions legislation. ELL successfully appealed to the LPSC to suspend the project for three years and was eventually left to recover the costs of the terminated project once it was permanently canceled.[388]

The initial plan was to recover the costs through a rate hike over five years.[389] However, ELL instead opted to securitize the termination costs in order to yield substantial savings for ratepayers. After facing pressure from ELL, the Louisiana legislature passed the 2010 Louisiana Electric Utility Investment Recovery Act ("Securitization Law"). The Securitization Law expanded upon previous securitization legislation by granting utilities the ability to issue ratepayer-backed bonds to finance various projects, including the cancellation of electric generating or transmission facilities.[390]

Following the enactment of the new state legislation, ELL requested permission from the LPSC to securitize over $207 million in stranded costs associated with the termination of the Little Gypsy repowering project.[391] The LPSC approved the request in 2011 and issued a financing order granting ELL's SPV, Entergy Louisiana Investment Recovery Funding I, LLC, the irrevocable right to impose, collect and receive over $207 million in non-bypassable consumption-based investment recovery charges from all existing or future customers receiving transmission or distribution service from ELL or its successors.[392] The financing order provided for limited exceptions to the non-bypassability of the charge, most notably the exclusion of customers who initiated new self-generation installations *before* May 1, 2011.

The bonds received an AAA rating based on the state's Securitization Law; the irrevocable financing order by the LPSC; the size and diversity of ELL's ratepayer base; and ELL's ability and

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[386] Saber Partners, LLC. "Experts Advise Expanded Use of Securitization by Utilities to Finance Range of Cost Recovery." https://saberpartners.com/press/electric-utility-week/, February 2011.

[387] United States of America Federal Energy Regulatory Commission. *Opinion No. 542.* https://www.ferc.gov/whats-new/comm-meet/2015/111915/E-27.pdf, November 2015.

[388] Saber Partners, LLC. "Experts Advise Expanded Use of Securitization by Utilities to Finance Range of Cost Recovery." February 2011.

[389] Ibid.

[390] LA SB619, *Louisiana Electric Utility Investment Recover Securitization Act.* 2010 Reg. Sess. Louisiana, 2010.

[391] The United States Securities and Exchange Commission. *$207,156,000 Entergy Louisiana Investment Recovery Funding I, L.L.C. Issuing Entity Senior Secured Investment Recovery Bonds.* https://www.sec.gov/Archives/edgar/data/1348952/000006598411000164/d230224d424b5.htm, September 2011.

[392] Ibid.

experience as a servicer amongst other reasons.[393,394] The LPSC approved the bonds in September 2011, leading to the sale of $207.2 million in investment recovery bonds.[395] The bonds were ultimately issued in a single tranche at an interest rate of 2.040% with an expected weighted average life of 5.27 years.[396] Net proceeds from bond sales were used to finance the costs associated with terminating the Little Gypsy repowering project.

At the time of securitization, the LPSC predicted that securitization would save ratepayers over $80 million when compared to the costs of traditional utility financing.[397]

While Entergy Louisiana and Entergy Gulf States have a history of using securitization to recover costs from natural disasters under the Louisiana Electric Utility Storm Recovery Securitization Act (2006), this was the first case of using securitization to cover the costs of terminating a power project in the state of Louisiana.

6.6.2.3 Duke Energy Florida (Florida, 2016)

In 2016, Duke Energy Florida, LLC ("DEF") used securitization to cover nearly $1.3 billion in costs associated with the retirement of their Crystal River III (CR3) nuclear power plant in Citrus County, Florida. The plant was initially closed in 2013 after a failed maintenance project left a series of cracks in the reactor's containment building, resulting in insurmountable structural problems. Once further repair was no longer economically viable, DEF turned to securitization to recover the costs associated with CR3's eventual retirement.

DEF first proposed a bond issuance in 2015, but state legislation had to be passed before it could be approved. In 2015, the Florida state legislature enacted securitization legislation permitting the Florida Public Service Commission ("FPSC") to impose irrevocable, binding, and non-bypassable nuclear asset-recovery charges on all future and existing ratepayers receiving transmission or distribution from DEF or its successors.[398] This, in turn, allowed electric utilities to access lower-cost funds using nuclear asset-recovery bonds in accordance with financing

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[393] Moody's Investors Service. "Approximately $207.156 million of asset backed securities rated." https://www.moodys.com/research/Moodys-assigns-highest-rating-to-investment-recovery-bonds-sponsored-by--PR_226709, September 2011.

[394] Louisiana Public Service Commission. "LPSC Bond Deal Saves Entergy Customers Millions." https://lpsc.louisiana.gov/_docs/_News/Press%20Release%209-11.pdf, September 2011.

[395] The United States Securities and Exchange Commission. *$207,156,000 Entergy Louisiana Investment Recovery Funding I, L.L.C. Issuing Entity Senior Secured Investment Recovery Bonds.* September 2011.

[396] Ibid.

[397] Louisiana Public Service Commission. "LPSC Bond Deal Saves Entergy Customers Millions." https://lpsc.louisiana.gov/_docs/_News/Press%20Release%209-11.pdf, September 2011.

[398] Section 366.95. *Financing for certain nuclear generating asset retirement or abandonment costs.* Florida Statutes, 2018.

orders issued by the FPSC.[399] Following the necessary legislation, the FPSC issued an irrevocable financing order granting the SPV, Duke Energy Florida Project Finance, LLC, the right to impose, bill, collect, and receive binding and non-bypassable nuclear asset-recovery charges on a per kWh basis from all of DEF transmission and distribution customers.[400]

The bonds received a AAA rating based on the strength of the state's securitization law; the irrevocable financing order issued by the FPSC; the size, stability, and diversity of DEF's ratepayer base in the service area; and DEF's ability and experience as a servicer amongst other reasons.[401] The FPSC approved the bonds in November 2016, resulting in the sale of $1.294 billion in nuclear asset-recovery bonds.[402] The bonds were issued in several tranches with maturities of 2, 5, 10, 15.2, and 18.7 years with interest rates 1.196%,1.731%, 2.538%, 2.858%, and 3.112% respectively.[403] Net proceeds from bond sales were used to recover DEF's investment in the CR3 regulatory asset.

While Duke Energy could have financed the cost of the CR3 closure itself, this approach might have forced customers to pay up to 40% more through higher finance charges over 20 years. Instead, the utility opted to sell the $1.3 billion in debt to investors with a lower return, leading to an estimated net present value savings of $700-790 million over 20 years. The initial charges on a 1,000 kWh-per-month residential customer bill decreased from $5.00 under traditional rate base recovery methods to just $2.87, saving ratepayers hundreds of millions over the life of the bonds.[404]

6.6.3 Review of legislative proposal

The Kansas Senate Bill 198 ("SB 198") would enable the retirement of existing generation assets and the securitization of the remaining book value of those retired asset value through the issuance of Kansas Energy Bill Reduction Assistance Bonds ("K-EBRA Bonds").

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[399] The United States Securities and Exchange Commission. *$1,294,290,000 Series A Senior Secured Bonds, Duke Energy Florida, LLC.* https://www.sec.gov/Archives/edgar/data/37637/000104746916013865/a2228973z424b1.htm, June 2016.

[400] Ibid.

[401] Moody's Investors Service. "Approximately $1.29 billion of securities affected." https://www.moodys.com/research/Moodys-assigns-Aaa-sf-to-Duke-Energy-Florida-Sponsored-Utility--PR_350955, June 2016.

[402] The United States Securities and Exchange Commission. *$1,294,290,000 Series A Senior Secured Bonds, Duke Energy Florida, LLC.* June 2016.

[403] Ibid.

[404] National Association of Regulatory Utility Commissioners. "State News: Nuclear Asset-Recovery Bonds Issued for Duke Energy Florida, LLC. https://www.naruc.org/bulletin/the-bulletin-062716/state-news-nuclear-asset-recovery-bonds-issued-for-duke-energy-florida-llc/, June 2016.

When analyzing whether securitization could benefit Kansas ratepayers, LEI conducted a review on SB 198 and found that certain terms written in SB 198 may limit the ratepayer benefits that securitization could generate.

6.6.3.1 Limitations on use of proceeds

SB 198 Section 1(b)(2) and Section 1(b)(3) state that the purposes of the ratepayer-backed bonds are "to provide transition assistance to Kansas communities and electric generation facility workers that are directly impacted by the retirement of electric generation facilities" and "to make available capital investment for renewable facilities and services, including least-cost electric generation facilities and other supply-side and demand-side resources."

SB 198 Section 15 requirements

Subject to commission approval as required by subsection (b) as provided in a financing order, an electric utility may expend or invest K-EBRA bond proceeds in a manner that demonstrably benefits ratepayer interests to:

(1) purchase power to replace electricity generated by the electric generation facilities that were retired, if the commission determines that the purchased power is a least-cost generation resource;

(2) build and own generation facilities that are least-cost generation resources as determined by the commission;

(3) build, own or purchase electricity storage capacity to the extent that such investment is either required by law or is needed to increase the amount of least-cost generation resources that the electric utility is able to add to such utility's generation portfolio;

(4) help customers invest in energy efficiency, including possible financing assistance; and

(5) invest in network modernization, not including new transmission facilities, to the extent that the modernization is necessary to increase the amount of least-cost generation resources able to be added to the electric utility's system.

LEI's interpretation of these two sections is that the use of proceeds from the securitization process has to be approved by the KCC and the utility cannot (a) reinvest the proceeds as they see fit, or (b) choose not to reinvest the proceeds and instead distribute the proceeds to its investors. This limitation in the use of proceeds has the following implications:

1. Even though the value of the asset securitized would be removed from the regulated utility's rate base, the entire value would be reinvested into new rate base assets (except in cases where it is used to support communities impacted by asset retirement). This reduces the ability to "right size" the asset base due to changes in demand outlook and network needs;
2. If the ratepayer-backed bond proceeds cannot be distributed back to investors of the regulated utility, the Kansas utility industry would lock up more capital than without securitization. This may not be the most efficient allocation of capital;

3. The utility would have less incentive to securitize their asset as they have less flexibility in how they want to use the proceeds; and,
4. If the ratepayer-backed bond proceeds are used for the purpose of providing transition assistance to Kansas communities and electric generation facility workers that are directly impacted by the retirement of electric generation facilities, the utility may end up worse off through securitization because the proceeds are neither used to reinvest in new for-profit assets nor are they distributed back to investors – effectively their rate base is reduced without compensation.

Based on these observations, LEI recommends the Kansas legislature approach the idea to require proceeds to be reinvested in rate base with caution. This is especially true since the Kansas legislature and the KCC are specifically interested in how to manage capex and opex in the Kansas electricity sector to achieve and sustain regionally competitive electricity rates.

In Section 6.1, LEI recommended that Kansas require utilities to submit Integrated Resource Plans ("IRPs"). A possible amendment to the proposed legislation could include linking the reinvestment of the ratepayer-backed bond proceeds with IRP investment requirements.

6.6.3.2 Limitations on types of assets that can be securitized

In SB 198 Section 1(b)(1), the legislation limits the proceeds of the ratepayer-backed bonds to be used in "reducing financing costs of certain ***retired electric generating facilities*** and related costs" [emphasis by LEI]. This means the securitization process can be used to finance retired electric generating facilities, but not environmental control equipment. While LEI has not conducted an engineering study on the condition of each Kansas coal-fired generating facility, some facilities may still have positive economic value. If the value of their environmental control equipment were securitized in these cases, electric rates could be lowered while requiring less new generation capacity.

We, therefore, suggest that SB 198 could be amended to allow the securitization of environmental control equipment if a cost-benefit study suggests that allowing the relevant generating facility to continue operating would result in a higher net benefit to ratepayers.

6.6.4 Illustrative impact of securitization in Kansas

In order to understand the potential effects of securitization in Kansas, LEI performed a high-level illustrative analysis of the potential impact of securitization on electricity rates in Kansas.

6.6.4.1 Which assets can be securitized?

First, SB 198 specifically states that the financing order is only applicable to the "retirement of an electric generating facility located in the state."[405] This means that generation units owned by Evergy but located in Missouri would not qualify for securitization under SB 198. Assuming that

[405] SB 198 Section 2(l)(a).

securitization would target coal-fired plants, coal-fired generation units owned by Evergy located within Kansas are Jeffrey Energy Center (2,187 MW), Lawrence Energy Center (484 MW), and La Cygne (1,398 MW). As of December 31, 2018, the net book value of Jeffrey Energy Center, inclusive of construction work in progress, is $1,565 million, and the net book value for La Cygne is $1,533 million.[406] However, the net book value of Lawrence Energy Center is not provided in Evergy's financial statements. Assuming the $/kW net book value of Lawrence Energy Center is the average of Jeffrey Energy Center and La Cygne, then its net book value would be approximately $438 million. The total value of these three plants represents $3,535 million.

When trying to estimate the potential rate impact of securitizing Evergy's coal generating assets, there are a number of key assumptions which would impact the result:

- If there is no securitization, what is the remaining useful life of the coal generation assets before Evergy would retire them?
- What would be the interest rate of the ratepayer-backed bonds?
- What would be the maturity of the ratepayer-backed bonds?

For this high-level illustrative analysis, LEI made the following assumptions:

- Based on the retirement of the Lawrence 3 unit after 60 years,[407] LEI assumed the three coal power plants normally would retire when their average unit age reaches 60 years old.
- LEI tested two ratepayer-backed bond rate scenarios. The first assumed the bond has the same interest rate as the cost of debt of KCP&L's most recent rate case, which is 4.9253%.[408] In the other scenario, LEI assumed ratepayer-backed bonds can achieve a higher credit rating than KCP&L, resulting in lower borrowing costs by 100 basis points and an interest rate of 3.93%.[409]
- LEI assumed the term of the ratepayer-backed bonds would correspond to the remaining life of the coal generation power plants plus five years.[410]

There are also costs associated with the securitization process, such as fees paid to financial advisors and legal costs. LEI assumed that this securitization cost amounts to 2% of the ratepayer-back bond issued.

Figure 141 presents a summary of the assumptions used in the analysis.

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[406] http://www.evergyinc.com/node/36621/html#s64F24538C378E0DBB80D142D98FB86DA page 104

[407] Lawrence 3 was built in 1955 and was retired in 2015.

[408] Docket No. 18-KCPE-480-RTS

[409] https://www.utilitydive.com/news/securitization-fever-renewables-advocates-seize-wall-streets-innovative-w/555089/

[410] The maximum maturity allowed for a K-EBRA bond under SB 198 is 32 years. SB198 Section 2(j)

Figure 141. Assumptions related to Evergy coal generation assets securitization analysis

Plant	Capacity (MW)	Net Book Value ($ million)	Net Book Value ($/MW)	Year built	Estimated remaining life (years)
Jeffrey Energy Center	2,187	1,565	0.72	1978, 1980 &1983	21
La Cygne	1,398	1,533	1.10	1973, 1977	16
Lawrence Energy Center	484	438	0.91	1960, 1971	7

Assumption	Value
Approved WACC for rate base	7.07%
Cost of debt for securitization - high	4.93%
Cost of debt for securitization - low	3.93%
Inflation	2.00%
Issuance cost (% of bond issued)	2.00%

Source: Evergy 10-K filing, commercially available database, KCC Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018, and LEI analysis

6.6.4.2 Difference in required return on assets

Based on the assumptions discussed in Section 6.6.4.1, LEI performed an illustrative example of the annual impact on overall costs for consumers using the case of the Jeffrey Energy Center with and without securitization.

Since the ratepayer-backed bond is assumed to have a maturity that is five-years longer than the remaining life of the generation asset, the ratepayer-backed bond continues to create ratepayer burden after the ratepayer burden under the "no securitization" case disappears.

Overall, securitization could provide savings early on through lower repayment terms than if the stranded assets remain in the utility rate base. However, the annual saving amounts grow smaller over time until they can represent a burden on rates in the later years when the asset would otherwise have been fully depreciated in the utility's rate base.

In LEI's illustrative example (see Figure 142), the additional cost for consumers over the debt repayment term would represent $82 million in nominal dollar terms. However, that number can be misleading, as inflation would actually mitigate the impact of later additional costs with respect to early savings. For example, an assumption of 0.5% annual inflation would result in no costs nor savings to consumers,[411] while an assumption of 2.0% annual inflation would result in over $100 million in savings to consumers over the term of the securitization.

[411] In other terms, a net present value analysis of the annual impact on customer costs (rightmost column in Figure 142) using a discount rate of 0.5% results in a value of 0.

Figure 142. Difference in ratepayer burden of Jeffrey Energy Center with and without securitization (nominal $ million)

Jeffrey Energy Center - No securitization

Year	Book value	Depreciation	Return on investment	Ratepayer burden
1	1,564.7	74.5	110.7	185.2
2	1,490.2	74.5	105.4	179.9
3	1,415.7	74.5	100.1	174.6
4	1,341.2	74.5	94.9	169.4
5	1,266.7	74.5	89.6	164.1
6	1,192.2	74.5	84.3	158.8
7	1,117.6	74.5	79.0	153.6
8	1,043.1	74.5	73.8	148.3
9	968.6	74.5	68.5	143.0
10	894.1	74.5	63.2	137.7
11	819.6	74.5	58.0	132.5
12	745.1	74.5	52.7	127.2
13	670.6	74.5	47.4	121.9
14	596.1	74.5	42.2	116.7
15	521.6	74.5	36.9	111.4
16	447.1	74.5	31.6	106.1
17	372.5	74.5	26.3	100.9
18	298.0	74.5	21.1	95.6
19	223.5	74.5	15.8	90.3
20	149.0	74.5	10.5	85.0
21	74.5	74.5	5.3	79.8
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0

Jeffrey Energy Center - Securitized

Year	Security value	Interest	Principal repayment	Rate payer burden	Difference (negative is savings)
1.0	1,596.0	78.6	31.6	110.2	(75.01)
2.0	1,564.4	77.1	33.1	110.2	(69.74)
3.0	1,531.3	75.4	34.7	110.2	(64.47)
4.0	1,496.6	73.7	36.5	110.2	(59.20)
5.0	1,460.1	71.9	38.3	110.2	(53.93)
6.0	1,421.8	70.0	40.1	110.2	(48.66)
7.0	1,381.7	68.1	42.1	110.2	(43.39)
8.0	1,339.6	66.0	44.2	110.2	(38.12)
9.0	1,295.4	63.8	46.4	110.2	(32.85)
10.0	1,249.0	61.5	48.7	110.2	(27.58)
11.0	1,200.4	59.1	51.0	110.2	(22.31)
12.0	1,149.3	56.6	53.6	110.2	(17.04)
13.0	1,095.8	54.0	56.2	110.2	(11.77)
14.0	1,039.6	51.2	59.0	110.2	(6.50)
15.0	980.6	48.3	61.9	110.2	(1.23)
16.0	918.7	45.2	64.9	110.2	4.04
17.0	853.8	42.1	68.1	110.2	9.31
18.0	785.7	38.7	71.5	110.2	14.58
19.0	714.2	35.2	75.0	110.2	19.85
20.0	639.2	31.5	78.7	110.2	25.12
21.0	560.5	27.6	82.6	110.2	30.39
22.0	478.0	23.5	86.6	110.2	110.17
23.0	391.3	19.3	90.9	110.2	110.17
24.0	300.4	14.8	95.4	110.2	110.17
25.0	205.1	10.1	100.1	110.2	110.17
26.0	105.0	5.2	105.0	110.2	110.17
27.0	-	-	-	-	-
				Total	**82.40**

Note: This analysis only compares the streams of payment between a rate-base and a securitized (4.93% interest rate) asset, and does not include the analysis related to the retirement of the asset – i.e., savings in operation costs versus the cost of replacement energy and capacity.

Source: LEI analysis

It is important to emphasize that the analysis presented in this section is illustrative and highly simplified. It does, however, illustrate the tradeoffs between lower rates in the short term versus longer repayment terms and the potential for overall costs.

Key takeaways

It is also important to separate the analysis of asset retirement versus securitization. As a first step before securitization is considered, a comprehensive and holistic analysis of the potential retirement of generation assets should be undertaken, including savings in fixed O&M and fuel costs, weighted against the cost of replacement services (energy, capacity, etc.). The macroeconomic impacts of these retirements should also be considered. If the decision to retire the asset is made, then securitization could be considered as an option to lower rates, but all the tradeoffs of such a decision should be considered.

6.7 Participation in SPP

SPP is a not-for-profit RTO mandated by FERC to manage reliability coordination, wholesale markets, and transmission services using its members' transmission systems.[412] SPP is directly regulated by FERC, which must approve any changes to SPP's Open Access Transmission Tariff ("OATT") ahead of implementation. The OATT defines the scope of the SPP operations and engineering mandate, including but not limited to operating the market and Balancing Authority ("BA"); provision of ancillary services; studying generation interconnection requests; evaluating long-term transmission service requests; and monitoring and mitigating SPP's markets.[413]

All SPP members are a party to the membership agreement ("MA"), and the RTO is governed by its bylaws. Changes to the MA and the bylaws are the responsibility of the Board of Directors, supported by the Market Operations and Policy Committee ("MOPC") and Corporate Governance Committee. There are several other committees and working groups with specific mandates and functions that support the decision-making of the Board and MOPC. Currently, there are six board-level committees, 18 working groups, and over 35 task forces and subcommittees.[414] These committees are largely populated by representatives from SPP's member companies. A summary of SPP's organizational structure is summarized in Figure 143 below.

Figure 143. SPP organizational chart

Source: SPP. *2020 Operating Plan*. May 2019.

[412] Southwest Power Pool. *2020 Operating Plan*. July 2019.

[413] Ibid. P. 3.

[414] Ibid. P. 4.

SPP established a real-time energy market in 2007 and transitioned to an integrated day-ahead and ancillary services energy market in March 2014, referred to as the Integrated Marketplace ("IM"). The IM serves market participants in all or part of 14 US states, including Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Iowa, Minnesota, Montana, North Dakota, South Dakota, and Wyoming. This footprint includes over 800 generating plants and over 60,000 miles of transmission lines.[415]

SPP's marketplace is served by over 89 GW of generation capacity, including 25.1 GW of coal generation, 36.1 GW of gas-fired generation, and 20.5 GW of wind generation.[416] The SPP generation mix has evolved over time, driven by low-cost natural gas from shale extraction and extensive wind resource installations. SPP remains oversupplied on a capacity basis, with a coincident peak demand of 49.9 GW in 2018, declining from just over 51 GW in 2017.[417]

Stakeholders' view on the SPP IM

The Kansas Industry Consumers ("KIC") has a generally positive view of the SPP IM, which allows economic dispatch of generation on a region-wide basis. However, some Kansas ratepayers have not seen the same benefits from SPP as wholesale participants or customers of other utilities.

The Kansas Municipal Energy Agency ("KMEA") has a similarly favorable view of the SPP marketplace, noting that it has helped access supply sources that would have been difficult to access before for small municipal utilities.

Source: KIC written comments; meetings with stakeholders on October 1, 2019

Driven by low-cost thermal and renewable generation, wholesale prices in SPP have remained below $30/MWh on average over the past four years, both in the real-time and day-ahead markets.[418] Two pricing hubs represent the regional differences, i.e., the North Hub and South Hub. The North Hub is a virtual hub representing a collection of pricing hubs around Nebraska, while the South Hub represents a collection of hubs around Oklahoma.[419] A summary of SPP's generation capacity and recent pricing trends is illustrated in Figure 144 below.

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[415] Southwest Power Pool website. *About us.* Accessed at: <http://www.spp.org/about-us/>

[416] Southwest Power Pool. *2018 Annual State of the Market Report.* May 2019.

[417] Ibid. P. 35.

[418] Ibid. P. 111.

[419] Ibid. P. 112.

Figure 144. SPP energy mix and historical prices

Sources: SPP. *2018 Annual State of the Market Report.* May 2019; Commercial third-party database accessed on November 24th, 2019.

All Kansas utilities are members of SPP, meaning they have transferred functional control of their transmission assets to SPP. As participating members of SPP, Kansas utilities receive transmission services from SPP, including Network Integration Transmission Services, and Point-to-Point service, and are assessed a service fee by SPP pursuant to Schedule 1A of SPP's tariff. Currently, the SPP fee is at 39.4¢/MWh for service in 2019 – this fee is capped at 43¢/MWh. Kansas utilities represent approximately 18% of the total load in SPP, referred to as its "load ratio share."

Figure 145. Relationship between SPP and Kansas utilities

Source: LEI analysis

SPP is allowed to recover up to 100% of its operating costs, including interest payments on outstanding debt, but excluding depreciation and amortization expenses.[420] A simplified summary of the relationship between SPP and its utilities is illustrated in Figure 145 below.

6.7.1 Relevant issues in SPP for Kansas utilities

While stakeholders have expressed their general satisfaction with participation in SPP, noting greater access to supply and decreasing wholesale prices, there are a number of issues that have been of particular concern to stakeholders in recent months, including issues such as transmission cost allocation.[421] We consider a few of those issues in this section.

6.7.2 Cost allocation framework

As noted in a previous chapter, SPP is responsible for cost allocation for new transmission lines, and typically the framework used is referred to as the Highway/Byway methodology. This methodology was developed by the SPP RSC which regroups regulators from all states with member utilities in SPP. The approach seeks to spread the costs of new transmission lines depending on the size and scope of the project, i.e., the larger the project, the greater the contribution from regional utilities.[422] This framework is summarized in Figure 146 below.

Figure 146. Highway/Byway cost allocation framework

Size of transmission project	Region pays	Local zone pays
Below 100 kV	0%	100%
Between 100 KV and 300 kV	33%	67%
Over 300 kV	100%	0%

Sources: FERC. *Order Accepting Tariff Revisions. (SPP Highway/Byway Methodology)* June 17, 2010.

This allocation framework has resulted in a large proportion of costs of transmission lines constructed within Kansas allocated to Kansas ratepayers, where a number of stakeholders

[420] Southwest Power Pool. *2020 Operating Plan.* July 2019. P. 5.

[421] Feedback received during meetings with Kansas stakeholders held on October 1, 2019.

[422] FERC. *Order Accepting Tariff Revisions. (SPP Highway/Byway Methodology)* June 17, 2010.

believe the benefits are accruing outside the state.[423] In their respective rate studies filed between 2018 and 2019, both KCC and Evergy identified additional transmission costs as a driver for increased retail rates, although Evergy noted that these would bring long-term regional benefits.[424,425]

To address concerns with cost allocation, among other issues, across the SPP footprint, in 2019, SPP commissioned the HITT to assess and recommend actions. The HITT report recommends a byway facility cost allocation review process, whereby specific projects between 100 kV and 300 kV can be allocated on a highway basis.[426] Under this recommendation, additional consideration would be given to regional benefits that result from these transmission projects, "including energy exports from the transmission pricing zone where each project is located."[427]

6.7.3 Stakeholder participation

Stakeholders have also expressed to LEI that there are limited opportunities for participation in SPP due to limits in resources and lack of avenues for participation. The munis noted they only participate in the key committees, and are unable to participate in, for instance, transmission planning committees due to insufficient resources.[428] A number of large customers, through KIC, indicated that there is no mechanism for customers to meaningfully participate other than at FERC. In particular, they stated concern with a lack of avenues to "stop or slow" increased transmission investment.[429]

In the next section, LEI discusses in greater detail the mechanisms available for participation in SPP committees and decision-making for Kansas regulators, stakeholders, and utilities.

6.7.4 Kansas participation in SPP committees

As noted previously, there are over 18 working groups and over 35 task forces and subcommittees within SPP. In general, the role of these working groups is to provide directives on the work that SPP is expected to accomplish in a given period.[430] Some task forces are created with specific

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[423] Comments of KIC, received on October 1, 2019.

[424] Kansas Corporation Commission. *Rate Study of Kansas City Power & Light and Westar Energy for the years 2008 to 2018.* December 2018

[425] Westar Energy & Kansas City Power & Light Co. *Kansas Rate Study. Exhibit A. Docket No. 19-KCPE-053-CPL.* January 2019.

[426] SPP Holistic Integrated Tariff Team. *Report: Preparing for a reliable and cost-effective future.* July 23, 2019.

[427] Ibid. P. 47.

[428] Comments received from stakeholders during in-person meetings held on October 1, 2019.

[429] Comments of KIC, received on October 1, 2019.

[430] Southwest Power Pool. *2020 Operating Plan.* July 2019.

focuses and mandates (e.g., ad-hoc) and are disbanded upon publication of their reports and recommendations or expiration of their mandate, such as the HITT. Other groups are responsible for ongoing reporting and recommendations, such as the Markets Working Group and Transmission Working Group. In this section, LEI reviews the working groups that Kansas utilities, regulators, and other stakeholders participate in. A summary of these relevant groups is shown in Figure 147 below.

Figure 147. SPP committees where Kansas stakeholders participate

Committee/Working Group	Kansas stakeholder participant	Committee mandate
Regional State Committee ("RSC")	KCC	The SPP Regional State Committee provides collective state regulatory agency input on matters of regional importance related to the development and operation of bulk electric transmission
Cost Allocation Working Group ("CAWG")	KCC	Supports the RSC in its mandate to address cost allocation matters
Markets and Operations Committee ("MOPC")	All Kansas utilities that are members of SPP appoint a representative to MOPC	The MOPC is responsible for developing and recommending policies and procedures related to the technical operations for the company
Transmission Working Group ("TWG")	KCC, Evergy, Sunflower, Kansas Power Pool, KEPCo,	Responsible for planning criteria to evaluate transmission additions, seasonal ATC calculations, seasonal flowgate ratings, oversight of coordinated planning efforts, and oversight of transmission contingency evaluations.
Market Working Group ("MWG")	KCC, Evergy, KMEA, KEPCo	Responsible for the development and coordination of the changes necessary to support any SPP administered wholesale market(s), including energy, congestion management and market monitoring
Economic Studies Working Group ("ESWG")	KCC, Evergy, Sunflower	ESWG advises and assists SPP staff, various working groups, and task forces in the development and evaluation principles for economic studies
Regional Tariff Working Group ("RTWG")	KCC, Evergy, Sunflower, Midwest Energy, KMEA, Empire District Electric	RTWG is responsible for development, recommendation, overall implementation and oversight of SPP's OATT. The RTWG advises SPP Staff on regulatory or implementation issues not specifically covered by the Tariff.
Strategic Planning Committee ("SPC")	Evergy, KEPCo	SPC is responsible for the development and recommendation of strategic direction for SPP
Operating Reliability Working Group ("ORWG")	Evergy, Sunflower, Empire District Electric	The ORWG develops, maintains, and coordinates implementation of policies related to the reliable and secure operation of the Bulk Electric System and ensures these operating policies are consistent with NERC and Regional Reliability Standards

Source: KCC annual report; utilities annual report; SPP website

6.7.5 Involvement of the Kansas Corporation Commission

KCC represents Kansas at the RTO as mandated by K.S.A. 74-633. Kansas utilities are members of SPP, and the KCC is authorized to "*participate fully in all decision-making bodies of such regional transmission organization, whether the decision of such bodies are advisory to or binding on the regional*

transmission authorization."[431] To this end, KCC has staff participate in various committees and working groups in SPP.[432]

The KCC is a member of the RSC, which provides state regulatory agency input on regional matters. Specifically, the RSC's primary responsibilities regard regional proposals in the following areas:

- scale and scope of participant funding for transmission enhancements;
- whether license plate or postage stamp rates will be used for regional access;
- Financial Transmission Rights ("FTR") allocation where a locational price methodology is used and the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights;
- planning for remote resources, i.e., whether transmission upgrades for remote resources will be included in the regional transmission planning process; and
- the approach for resource adequacy in the region.[433]

The membership of the RSC includes one designated commissioner from each state regulatory commission that has jurisdiction over an SPP member.[434] Kansas is currently represented by Commissioner Albrecht and was the predecessor to the current chair of the RSC.

The RSC oversees SPP's Cost Allocation Working Group ("CAWG") and is a critical function of SPP governance. The RSC exercises this authority through its evaluation of the extent to which participation funding in SPP will be used for transmission enhancements, and if license plate or postage stamp rates will be used for regional access charges.[435] KCC staff are active participants in the CAWG, participating in cost allocation issues as and when they arise and are evaluated by this working group.

6.7.6 Involvement of Kansas utilities

All Kansas utilities are members of SPP and are active participants in the SPP decision-making process. Utilities will participate and submit comments to various working groups as well as intervene at FERC with respect to certain dockets. As shown in Figure 147 above, Kansas member

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[431] Kansas Statutes K.S.A. 74-633. *Representative to regional transmission organization, authority.*

[432] During stakeholder sessions, KCC staff noted that they have six staff either attending or monitoring the various working groups in SPP to fulfill this mandate.

[433] Southwest Power Pool. *Governing Documents Tariff. Bylaws. First Revised Volume No. 4.* August 2010.

[434] Southwest Power Pool. *The History of The Regional State Committee for the Southwest Power Pool, Inc. 2019 Version.* April 29, 2019.

[435] Ibid.

utilities participate in several SPP working groups, where the utilities can represent their interests within the framework of the specific working group.

Utilities also participate in the SPP Stakeholder Prioritization Process. Given the many issues that the SPP Markets and Operations Committee ("MOPC") has to consider at its regular meetings, the prioritization process is a framework for stakeholders to provide input into what is given priority.[436]

Issues that are considered for this prioritization process are projects, tariff revision requests, and market enhancements. Once the item has been submitted via SPP's Request Management System ("RMS"), an assessment of the initial priority of the item is done by staff and/or the relevant working group. This is followed by the publication of the SPP Portfolio Report, which is a quarterly report reflecting the latest inventory of revision requests, projects and enhancements. This is followed by a stakeholder comment period and open Stakeholder Prioritization Quarterly Meeting. Following this process, SPP will publish an adjusted portfolio report.[437] This process is summarized in Figure 148 below.

Figure 148. Overview of SPP stakeholder prioritization process

Source: Southwest Power Pool. *Stakeholder Prioritization Process. Version 7.0.* January 27, 2017

SPP staff facilitates the Stakeholder Prioritization Quarterly Meeting, and it is open to all stakeholders and interested parties where stakeholder questions and comments are addressed with respect to the items under consideration. Following this meeting, portfolio adjustments may be made to reflect stakeholder feedback, ahead of the publication of the Adjusted SPP Portfolio Report. The Adjusted SPP Portfolio will then be posted on the SPP website ahead of the MOPC meeting.

6.7.7 Evaluating the effectiveness of the current approach

LEI understands that there are a number of avenues where both Kansas utilities and the regulator can participate in SPP. Stakeholder comments on the existing mechanisms for SPP participation

[436] Southwest Power Pool. *Stakeholder Prioritization Process. Version 7.0.* January 27, 2017.

[437] Ibid. P. 3.

received by LEI staff suggest that while there are various channels for feedback, not all issues have been taken into consideration.

The current framework in SPP for stakeholder feedback is consistent with best practices for engaging with a variety of stakeholders with potentially conflicting positions. The literature on policymaking and stakeholder engagement suggests that the best processes are concerned with bringing all individuals that may be impacted by a decision into roles of decision-making.[438,439] The International Association of Public Participation ("IAP2") defines a spectrum of participation entailing five broad levels of increasing involvement in the engagement process:

a) ***Inform***: provision of balanced and objective information (e.g., fact sheets, websites, open houses);

b) ***Consult***: obtaining public feedback on analysis and/or alternatives (e.g., public comment, focus groups, surveys, public meetings);

c) ***Involve***: working with stakeholders throughout the process (e.g., workshops, deliberative polling);

d) ***Collaborate***: partnering with the stakeholders at each step of the process (e.g., citizen advisory committees, consensus building, participatory decision making); and

e) ***Empower***: placing the decision-making at the hands of the stakeholders (e.g., citizen juries, delegated decisions)[440]

Considering the framework above, LEI believes that the existing framework might be improved with additional involvement of end customers and additional empowerment of all stakeholders. The textbox below describes such a mechanism in PJM.

Kansas stakeholders seeking to advocate certain positions within SPP might also consider a stronger state support framework for more extensive participation in working groups, or in the prioritization process. However, it is important to note that the creation of a role for additional stakeholders such as end-use customers or a participant support program comes with added costs and risks creation of greater regulatory uncertainty and delays. Further, advocating for greater customer empowerment may have an adverse impact on strengthening the voice of stakeholders with positions adverse to Kansas customers. A summary of LEI's evaluation of the SPP stakeholder process with respect to opportunities for Kansas participation is summarized in Figure 149 below.

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[438] Chan, Jennifer. *A Tool for the Public Policy Process & Stakeholder Engagement*. Diss. OCAD University, 2016.

[439] OECD. *OECD Best Practice Principles On Stakeholder Engagement In Regulatory Policy. Draft.* March 2017.

[440] International Association for Public Participation ("IAP2") IAP2's Public Participation Toolbox. 2007. Accessed November 24, 2019. Accessed at: <https://www.lgnsw.org.au/files/imce-uploads/346/IAP2-Public-Participation-Spectrum-LGNSW-Amalgamation-Toolkit.pdf>

PJM Stakeholder Participation and User Groups

PJM Interconnection is the RTO for the Midwest region, covering part or all of the states of Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Ohio, Kentucky, Indiana, Illinois and North Carolina. PJM has a two-tiered governance structure, with separate roles and responsibilities for the Board of Managers, and the Members Committee. Each PJM member has one primary representative and up to three alternate representatives on the Members Committee, and all other committees, subcommittees, and task forces with the authority to act for that PJM Participant.

The Members Committee has five Sectors where qualifying members may vote in, and they include: generation owners; other suppliers, transmission owners, electric distributors, and end-use customers. Each PJM Member may vote in only one sectors for which it qualifies. One stakeholder mechanism that exists outside these standard voting procedures are User Groups.

A User Group is stakeholder group formed by any five or more Voting Members sharing a common interest e.g. environmental regulation, nuclear issues, etc. Any recommendation or proposal for action adopted by vote of three-fourths or more of the members of a User Group shall be submitted to the Chair of the Members Committee for further consideration. Currently, there are two User Groups in PJM, the Public Interest, Environmental Organization User Group ("PIEOUG") and the Nuclear Generation Owners User Group ("NGOUG").

Source: PJM. *PJM Manual 34: PJM Stakeholder Process.* Effective September 2019.

Figure 149. Summary of evaluation of SPP stakeholder process

Participation framework principle	Existing SPP mechanism	Kansas stakeholders involved	Additional action recommended
Inform	▪ SPP website ▪ Request Management System ("RMS")	▪ KCC ▪ Utilities	None
Consult	▪ Existing working groups and committees	▪ KCC ▪ Utilities	Potential scope for more customer engagement support
Involve	▪ Existing working groups ▪ Stakeholder prioritization process	▪ KCC ▪ Utilities	None
Collaborate	▪ Regional State Committee ▪ Stakeholder prioritization process	▪ KCC ▪ Utilities	Advocate for additional roles for end consumers and customers
Empower	▪ Markets and Operations Policy Committee	▪ Utilities (and members)	None

Source: LEI analysis

Key takeaways

Recent trends in SPP, such as declining wholesale costs and increasing consideration of transmission cost allocation issues, suggest that the drivers of retail costs attributable to participation in SPP are already being addressed, and may occur without increased spending on advocacy at SPP.

6.8 Review of tax rates paid by utilities in Kansas and neighboring states

As stated in the Substitute for Senate Bill No. 69, LEI's Study of the retail rates of Kansas electric public utilities shall assess whether *"Kansas sales tax, property taxes, assessment rates, and other fees and taxes on utilities are comparable to other states in the region and how such taxes and fees impact the competitiveness of utility rates."*[441] This clause was included in the legislation after stakeholders raised the issue that taxes in Kansas were higher than those in neighboring states. For instance, public utilities in Kansas are subject to a high sales and uses tax of 6.50% (compared to a regional average of 5.15%[442]), as well as a state sales and use and corporate income tax rate of 7.00% (compared to a regional average of 5.19%[443]).[444,445]

The general perception among various stakeholders that tax rates in the state are high, and that the cost of tax rates for utilities may ultimately be passed through to ratepayers, led to the introduction of Senate Bill 126 by the Committee on Assessment and Taxation. The Bill seeks to exempt public utilities from paying state corporate income taxes for tax years 2019 to 2022.[446] According to testimony from the Kansas Industrial Consumers ("KIC") Group in support of the Bill, state corporate income taxes are currently being *"passed through and paid by Kansas utility customers as a component of utility rates,"* and therefore the implementation of the Bill should provide savings for customers.

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[441] Kansas Legislature. *Substitute for Senate Bill No. 69.* April 18, 2019.

[442] Regional sales and use tax rate taken as the average of neighboring states (Kansas included), namely, Arkansas, Colorado, Iowa, Kansas, Missouri, North Dakota, Oklahoma, South Dakota, and Texas.

[443] Regional state corporate income tax rate taken as the average rate applied to the highest tax bracket for neighboring states (Kansas included), namely, Arkansas, Colorado, Iowa, Missouri, North Dakota, Oklahoma, South Dakota, and Texas. South Dakota and Texas are assigned with a value of zero (0.00%) because they do not levy this tax.

[444] Constitution of the State of Kansas. *Article 11, Section 1.* November 6, 2012.

[445] Kansas Statutes. *Chapter 79, Article 32, Section 110.* 2018.

[446] Kansas Legislature. *Senate Bill No. 126.* February 7, 2019. (Note: This Bill is pending Senate Utilities Committee, which is currently in recess. At the close of the 2019 session, the Bill had reached 25% progression – source: LegiScan. "Kansas Senate Bill 126." <https://legiscan.com/KS/bill/SB126/2019>

6.8.1 Overview of the key taxes paid by utilities in Kansas

To properly assess how taxes are impacting the competitiveness of utility rates in Kansas, it is important to understand the different taxes that utilities in the state are obligated to pay. Figure 150 provides a summary of these taxes, which are discussed in further detail below.

Kansas corporate income tax is the tax imposed on the taxable income of corporations doing business within Kansas or deriving income from sources within the state. The tax consists of a regular tax rate of 4% on Kansas taxable income, plus an additional surtax of 3% on Kansas taxable income in excess of $50,000.[447]

Kansas sales and use tax is imposed on the state's retailers on their retail sales of tangible personal property, as well as the labor services required to install, apply, repair, service, alter, or maintain the tangible personal property. At the state level, the sales tax rate is 6.5%, effective as of July 1st, 2015.[448,449]

Figure 150. Summary of taxes paid by utilities only in Kansas

Tax	Rate
Kansas corporate income tax	Normal tax rate: 4%
	Surtax: 3%
Kansas sales and use tax (on purchase	6.50%
Local sales and use tax (on purchases)	Cities: 3% - 2% general, 1% special
	Counties: 1% general
Kansas unemployment tax	Positive account balance: 0%-4.9%
	Negative account balance: 5.1%-7.1%
	New employers: 2.7%
State and local property tax	Assessment rate: 33%
	Mill levy: 134.743% (average of all counties)

Local sales and use tax– in addition to the Kansas sales and use tax, retailers of tangible personal property are also required to pay local sales tax imposed by cities and counties in Kansas. Cities

[447] Kansas Statutes. *Chapter 79, Article 32, Section 110.* 2018.

[448] Kansas Department of Revenue. "Sales (Retailers)." <https://www.ksrevenue.org/bustaxtypessales.html>

[449] Kansas Rural Electric Cooperatives Accountant's Association. *Sales & Use Tax Rules for Electric Cooperatives.* October 28, 2016.

can impose a maximum sales tax rate of 3%, comprising up to 2% general tax and 1% special tax.[450] On the other hand, counties can impose a maximum general sales tax rate of 1%.[451]

It is worth noting that state and local sales and use taxes in Kansas are levied on retail sales, collected by the retailer from customers, and remitted by the retailer to the state through the Department of Revenue.[452]

Kansas unemployment tax applies to a wage base of $14,000 (for 2019).[453] The state employer tax rate varies according to employers' reserve ratios,[454] or previous history of claims. For employers with a positive account balance, the tax rate ranges from 0%-4.9%.[455] For employers with a negative account balance, the tax rate ranges from 5.1%-7.1%.[456] Finally, for new employers in the electricity industry, the tax rate is 2.7%.[457]

State and local property tax – public utilities in Kansas are treated separately for property tax purposes, with utility property assessed and apportioned to the local taxing districts by the state's Department of Revenue, Division of Property Valuation.[458] An assessment rate of 33% is applied to the appraised value of public utility real property to determine the assessed value.[459] The assessed value is then multiplied by the mill rate established by the county in which the property is located to obtain the property tax due.[460]

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[450] Kansas Department of Commerce. "Sales and Use Tax." <https://www.kansascommerce.gov/the-kansas-edge/exemptions-financing-incentives-taxes-unemployment/taxes/sales-and-use-tax/>

[451] Ibid.

[452] Kansas Department of Revenue. *Sales Tax and Compensating Use Tax.* October 2019.

[453] Kansas Department of Labor. "Employer Tax Rates." <https://www.dol.ks.gov/employers/tax-rates/2019-tax-rates>

[454] This ratio is obtained by dividing an account balance that indicates an employer's experience with unemployment and the average of the taxable payrolls for the past three years.

[455] Ibid.

[456] Ibid.

[457] Ibid.

[458] Kansas Department of Commerce. "Tangible Property Tax." <https://www.kansascommerce.gov/the-kansas-edge/exemptions-financing-incentives-taxes-unemployment/taxes/tangible-property-tax/>

[459] Constitution of the State of Kansas. *Article 11, Section 1.* November 6, 2012.

[460] Lexology. "State and Local Taxes in Kansas." November 27, 2018. <https://www.lexology.com/library/detail.aspx?g=00f4f361-28c3-4154-ac2d-dd803aae607b> (Note: The mill levy is the tax rate levied on the property value, whereby one mill represents one-tenth of one cent).

Special taxing districts' taxes are also applicable to utilities' purchases;[461] however, the significant variation between different jurisdictions makes their comparison not straightforward.[462]

Most of the taxes summarized above are paid by the IOUs in Kansas, including Evergy and Empire District Electric Company. Conversely, most co-ops and munis in the state are eligible for various tax exemptions.

Most of the co-ops in the state are exempt from paying income taxes, so long as they receive 85% or more of their income from members for the sole purpose of covering losses and expenses each year.[463] Regardless, co-ops that are eligible to file income tax exemptions need to report their activities to the Internal Revenue Service ("IRS") through IRS Form 990, Return of Organization Exempt From Income Tax.[464]

On the other hand, munis are exempt from paying federal income taxes and have access to tax-exempt bonds that can be used to fund capital projects.[465] Munis instead make payments in lieu of taxes ("PILOTs") to their respective cities' general funds, calculated as a percentage of revenues.[466]

Other tax exemptions include those provisions related to sales taxes, including but not limited to exemptions for the following:[467,468,469]

- agricultural, manufacturing, and residential uses, and severance of oil and gas;
- labor services used in original construction;
- tangible personal property purchased by a public utility for consumption or direct and immediate movement in interstate commerce; and

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[461] Corresponding email dated November 1, 2019 with Evergy's Investor Relations Department.

[462] For a complete list on local taxing jurisdictions and tax rates for all addresses in the state of Kansas see Kansas Department of Revenue. "Kansas Sales and Use Tax Address Tax Rate Locator." Web. <https://www.kssst.kdor.ks.gov/lookup.cfm>.

[463] IRS. *IRC 501(c)(12).* August 9, 2006.

[464] Wheatland Electric. "Your Cooperative Believes in Transparency." <https://www.weci.net/your-cooperative-believes-transparency>

[465] Moore, Adrian T. and Woerner, Jeff. *Integrating Municipal Utilities into a Competitive Electricity Market.* June 1, 2000.

[466] Kansas Municipal Utilities. "Benefits of Municipal Utilities." <https://www.kmunet.org/page/Benefits?&hhsearchterms=%22payments+and+lieu+and+tax%22>

[467] Kansas Rural Electric Cooperatives Accountant's Association. *Sales & Use Tax Rules for Electric Cooperatives.* October 28, 2016.

[468] Kansas Office of Revisor of Statutes. *K.S.A. 79-3603.*

[469] Kansas Office of Revisor of Statutes. *K.S.A. 79-3606.*

- under the integrated plant theory, machinery such as pollution control equipment.

Similarly, tax exemptions for state and local property taxes exist as well. For example, the construction or expansion of electricity generating facilities in Kansas are tax exempted – independent power producers are eligible for tax exemption for 12 years, while regulated public utilities are eligible for ten years.[470] Additionally, regulated public utilities receive a 10-year property tax exemption for transmission lines and equipment, as long as these were constructed after January 1, 2001.[471] However, nuclear power plants are not eligible for this exemption.[472]

6.8.2 Tax rates in other states

Below, LEI will compare the statutory rates of the sales and use tax and the corporate income tax applied by Kansas, with that of states in the studied region, including Arkansas, Colorado, Iowa, Missouri, North Dakota, Oklahoma, South Dakota, and Texas. Also, LEI describes the difference in the assessment rates used to estimate the property tax by each of the states previously defined. In addition, LEI explains some other taxes applicable to electric utilities in a non-exhaustive fashion due to limited information.

6.8.2.1 Sales and use tax

The sales and use tax includes the state-level tax on electricity sales[473] collected by utilities from consumers and the state-level tax applied on utilities' purchases. The reason for this aggregation is that the two types of taxes usually use the same base tax rate.

Although local-level taxes for the same purposes are also applied, LEI has decided not to consider them due to their significant variation among different jurisdictions (cities, counties, special purpose districts, and transit authorities) and restricted information available. However, it is worth mentioning that these local-level taxes could be relevant in combination with their state-level counterparts.

Arkansas and Kansas rates exceed all other seven states in terms of the sales and use tax rate. The sales and use tax rates of the States studied fall within the range of 2.90% and 6.50%, and the regional average is at 5.15%, as shown in Figure 151. Colorado falls behind all others, with only 2.90%.[474]

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[470] Kansas Department of Commerce. "Property Tax Exemptions for Electrical Power and Renewable Energy Generators." <https://www.kansascommerce.gov/the-kansas-edge/exemptions-financing-incentives-taxes-unemployment/exemptions/property-tax-exemptions-for-renewable-energy-generators/>

[471] Ibid.

[472] Ibid.

[473] North Dakota is the only state analyzed that does not apply sales and use tax on electricity sales.

[474] Limited information available does not allow LEI to perform a comprehensive assessment on how lowering the sales and use tax to its regional average could impact Kansas rates.

There is no universal exemption on the sales and use tax in the states included in this Study. Each state has its own exemption rules. Nevertheless, it appears the manufacturing sector and residential uses benefited the most from this exemption. The considered states exempt the following sectors/activities from paying this type of tax:

- Arkansas - manufacturing use;[475]
- Oklahoma - only residential use;[476]
- Colorado - specific activities and all industrial and residential uses;[477]
- Texas - agricultural, residential and specific manufacturing uses;[478]
- Iowa - prioritizes manufacturing/processing and residential uses exemptions;[479]
- Kansas[480] and Missouri[481] - agricultural, manufacturing and residential uses;
- South Dakota - government agencies, public corporations and schools, non-profit hospitals, and relief agencies.[482]

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[475] State of Arkansas – Bureau of Legislative Research. *Arkansas Legislative Tax handbook 2016*. October 11, 2016. <http://www.arkleg.state.ar.us/assembly/2017/Summary%20Budget%20Manuals/2016_Tax_Handbook.pdf>

[476] Oklahoma Tax Commission. *O.A.C. § 710:65-13*. <https://www.ok.gov/tax/documents/rule6509.pdf>

[477] Colorado Department of Revenue – Taxation Division. *Colorado Sales Tax Guide*. Web. June 2019. <https://www.colorado.gov/pacific/sites/default/files/Colorado%20Sales%20Tax%20Guide.pdf>

[478] Texas Administrative Code. *Title 34, Part 1, Chapter 3, Subchapter O, Rule §3.295, Article 9(c)*. < https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=34&pt=1&ch=3&rl=295>

[479] Iowa Code 2019. *Chapter 423.2 – Tax imposed*. December 2018.

[480] See Section 6.8.2.1 for a detailed description about Sales and Uses tax exemptions.

[481] Missouri Department of Revenue. "Listing of Missouri Sales and Use Tax Exemptions and Exclusions." Web. Downloaded November 8, 2019. <https://dor.mo.gov/business/sales/exemption-list.php>

[482] South Dakota Department of Revenue. "Exempt Entities." Web. March 2011. <https://dor.sd.gov/media/sgxnhnhl/exemptentities.pdf>

Figure 151. Sales and use tax rates (state-level)

Sources: Arkansas Department of Finance and Administration, Colorado Department of Revenue, Iowa Department of Revenue, Kansas Department of Revenue, Missouri Department of Revenue, North Dakota Office of State Tax Commissioner, Oklahoma Tax Commission, South Dakota Department of Revenue, Texas Comptroller of Public Accounts.

6.8.2.2 Corporate income tax

The corporate income tax consists of federal and state corporate income taxes. The difference in corporate income tax only lies in the state corporate income tax. See Figure 152 below for a complete description of how each state levies the tax based on its taxable income. Electric utilities most likely will fall under the highest income bracket. Hence, the statutory rates of the Corporate Income Tax, for comparison purposes in this Study, are shown in Figure 152 below.

Figure 152. Corporate income tax rate (state-level)

State	Corporate income tax rate
Arkansas	1.00% on first $3,000; 2.00% on next $3,000; 3.00% on next $5,000; 5.00% on next $14,000; 6.00% on next $75,000; 6.50% over $100,000 (For over $100,000, the rate will decrease to 6.20% and 5.90% in 2021 and 2022, respectively)
Colorado	4.63%
Iowa	Current: 6.00% up to $25,000; 8.00% between $25,000 - $100,000; 10.00% between $100,000 - $250,000; 12.00% over $250,000. Beginning 2021: 5.50% up to $100,000; 9.00% between $100,000 - $250,000; 9.80% over $250,000
Kansas	4.00% of taxable income + additional surtax of 3.00% over $50,000
Missouri	6.25% (4.00% beginning 2020)
North Dakota	1.41% on first $25,000; $352.50 + 3.55% on next $25,000; $1240.00 + 4.31% over $50,000
Oklahoma	6.00%
South Dakota	0.00%
Texas	0.00%

Sources: Arkansas Legislature SB 576, Colorado Legislature, Iowa Department of Revenue, Kansas Statutes, Missouri Legislature - SB 884, North Dakota Tax Commissioner, Oklahoma Tax Commission, Tax Foundation.

The regional average corporate income tax rate is 5.19% for the highest income bracket. Iowa has the highest corporate income tax rate, 12%, far exceeding the other selected states, which are in the range of 4.00% to 7.00% (or, in the case of SD and TX, 0%). Kansas ranks the second highest (7.00%), followed by Arkansas, Missouri, and Oklahoma, which have tax rates between 6.00% and 7.00%. North Dakota and Colorado rates are among the lowest, 4.31%, and 4.63%, respectively. Finally, South Dakota and Texas do not levy a corporate income tax. However, Texas imposes a gross receipts tax instead (see Section 6.8.2.4). Kansas' corporate income tax rate is above the average of the regional corporate income tax rate for the highest income bracket.

Some of these rates will change soon. For example, Iowa will decrease its rate by 2.20 percentage points in 2021,[483] and Arkansas will reduce its tax rate to 5.90% in 2022.[484] The ranking will remain the same except for Arkansas, Missouri, and Oklahoma, which will switch positions to Missouri, Oklahoma, and Arkansas in terms of the lowest tax rate among the states included in this Study.

Figure 153. Prevailing corporate income tax rate (state-level)

Sources: Arkansas Legislature SB 576, Colorado Legislature, Iowa Department of Revenue, Kansas Statutes, Missouri Legislature - SB 884, North Dakota Tax Commissioner, Oklahoma Tax Commission, Tax Foundation.

Based on the Kansas-specific tax information available in the 2018 rate case of Kansas City Power & Light Company,[485] LEI estimated the potential impact of reducing Kansas corporate income tax from its current level (7.00%) to its regional average level (5.19%) on KCP&L's electricity rate.

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483 Iowa Department of Revenue. "Iowa Tan Rate History". Web. Downloaded November 11, 2019. <https://tax.iowa.gov/iowa-tax-rate-history>

484 Arkansas State Legislature. *Senate Bill No. 576*. April 9, 2019. <http://www.arkleg.state.ar.us/assembly/2019/2019R/Acts/Act822.pdf>

485 Application for KCP&L Rate Case. Docket No. 18-KCPE-480-RTS <http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20180501162757.pdf?Id=78094501-bdab-4036-bee9-a1cd37fc2311>

This proxy approach exhibits that a 26% decrease in the state corporate income tax will lead to a 0.3% reduction in KCP&L's electricity rate.[486]

6.8.2.3 Property tax

The property tax is levied based on the assessed value of the property owned by each electric utility and the property tax rate determined by the local taxing jurisdictions. While the assessed value is determined at the state level considering their assessment rates, it is the local taxing jurisdiction that is responsible for applying the respective tax rates, which is generally measured in mills (amount per $1,000 of the applicable tax base) and issuing tax bills.

LEI has identified that the assessment rate is a key component for analyzing the property tax, but it varies significantly among jurisdictions, and such information is not always publicly available. LEI was able to obtain the information of seven out of the nine states in the Study, the comparison of which shows considerable variation from the lowest of 5% in Iowa going all the way up to 100% in Texas. As illustrated in Figure 154, Kansas has the second highest assessment rate despite falling below the regional average of 35% once Texas is considered in the sample. If Texas is not considered in the group, Kansas has the highest assessment rate among the states and the regional average rate is 23%.

Iowa is not included in the comparison above because it has replaced its property tax on electric companies with an excise tax based on the utility's ownership in transmission line property, electricity deliveries, and electric generation. In addition, this new regulation enacted a statewide property tax of three cents per one thousand dollars of assessed value on the operating property.[487]

Taking a similar approach for estimating the potential impact of state corporate income tax reduction on KCP&L's electricity rate (see Section 6.8.2.2), LEI estimated the impact on the KCP&L's electricity rate due to a lower property tax through decreasing the current assessment rate (33.00%) to the regional average level (22.97%).[488] This proxy estimate shows that a 30% reduction in the assessment rates will imply a decrease of approximately 1.8% on KCP&L's electricity rate.[489]

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[486] The formula used to estimate the impact on rate of reducing the state corporate income tax rate to its regional average is described as follow: rate impact = [current state income tax x state corporate income rate reduction] / total electric operating revenue.

[487] Iowa Code 2019. *Chapter 437A – Taxes on Electricity and Natural Gas Providers*. December 2018.

[488] The regional average without including Texas was considered in the calculations.

[489] Similar to the former section, the methodology applied to estimate the impact on electric rate of a reduction of the assessment rate to its regional average was the following: rate impact = [property taxes x assessment rate reduction] / total electric operating revenue.

Figure 154. Assessment rates by states

Sources: Kansas State Library, North Dakota Tax Commissioner, and North Dakota Association of Counties. Also, information collected through communication with the Arkansas Assessment Coordination Department, Colorado Department of Local Affairs, Oklahoma Tax Commission, Texas Comptroller of Public Accounts.

6.8.2.4 Other taxes

In addition to the state and ad valorem taxes described above, electric utilities are also subject to other state and local taxes/fees that vary across jurisdictions. Information on these specific taxes/fees is generalized at the state level and difficult to collect exhaustively. In this section, LEI will describe some of them for selected states where information is available and accessible.

Arkansas. There are at least two other taxes paid by electric utilities in Arkansas: the unemployment insurance state tax and public service commission service fee. The unemployment insurance state tax rates are between 0.10% and 5.00% (plus a stabilization rate).[490] The public service commission fee is an amount that cannot exceed 0.40% of the gross earnings of each utility.[491] A local franchise tax applies to electric utilities.

[490] Arkansas Division of Workforce Services. "Employer UI Contributions." Web. Downloaded November 8,2019. <https://www.dws.arkansas.gov/employers/employer-ui-contributions/>

[491] State of Arkansas – Bureau of Legislative Research. *Arkansas Legislative Tax handbook 2016*. October 11, 2016. <http://www.arkleg.state.ar.us/assembly/2017/Summary%20Budget%20Manuals/2016_Tax_Handbook.pdf>

North Dakota. A coal conversion facility, with a generating capacity of 10 MW or more, is taxed at a flat rate of 37.5 cents per ton. This tax is in lieu of property taxes on all property except land.[492]

Missouri. This state presents a similar taxation scheme as Kansas with some minor differences. Its unemployment state tax considers a wage limitation of $12,000 and a tax rate between 0.00% and 9.00%, except for new employers, which is 2.38%.[493] In addition, Kansas City (Missouri) imposes a tax of 1.00% on wages and salaries.[494] Special taxing district's taxes are also applicable to utilities' purchases; however, this information is not publicly available.[495]

Oklahoma. The state unemployment tax rate ranges between 0.10% and 5.50%, and the tax rate for a new employer is 1.50%. The taxable wage base set by the state is $18,100.[496]

South Dakota. Rural electric cooperatives must pay a gross receipts tax up to 2% of the total gross revenue collected for that year.[497]

Texas. An electric company in Texas faces three additional taxes at the state level:[498] the (i) gas, electric and water utility tax, (ii) the public utilities gross receipts assessment, and (iii) the franchise tax. The gas, electric, and water utility tax have a rate ranging from 0.581% to 1.997% of gross receipts depending on the city's population.[499] The public utilities gross receipts assessment

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[492] North Dakota Office of State Tax Commissioner. "Coal Severance Tax." Web. Downloaded November 8, 2019 <https://www.nd.gov/tax/user/businesses/formspublications/coal-severance-tax>

[493] Missouri Department of Labor and Industrial Relations. "Tax Rates." Web. Downloaded November 8, 2019. <https://labor.mo.gov/DES/Employers/tax_rates>

[494] City of Kansas City, Missouri. "Earnings Tax." Web. Downloaded November 8, 2019. <https://www.kcmo.gov/city-hall/departments/finance/earnings-tax>

[495] Corresponding email dated November 1, 2019 with Evergy's Investor Relations Department.

[496] Oklahoma Employment Security Commission. "Taxable Wage Base and Rates" Web. Downloaded November 8, 2019. <https://www.ok.gov/oesc/Businesses/Taxable_Wage_Base_and_Rates.html>

[497] South Dakota Legislature - Legislative Research Council. *Codified Laws § 49-34A-45.* <https://sdlegislature.gov/Statutes/Codified_Laws/DisplayStatute.aspx?Type=Statute&Statute=49-34A-45>

[498] See Association of Electric Companies, INC. "State and Local Taxation of the Electric Industry in Texas". Web. 2017. <http://aect.net/documents/2017/AECT%20Taxes%202017.pdf> for a detailed discussion of tax impact on the members of the Association of Electric Companies of Texas.

[499] Texas Comptroller Manual of Accounts - Fiscal 2020. "Revenue Object 3233 – Gas, Electric and Water Utility Tax" Web. Downloaded November 8, 2019. <https://fmcpa.cpa.state.tx.us/fiscalmoa/rev.jsp?num=3233>

charged utility's gross receipts at 0.001667%.[500] Lastly, the franchise tax levies a 0.75%[501] tax on a taxable margin calculated as the lesser difference between utility's gross revenue and three optional deductions (cost of goods sold, labor compensation expenses, or a flat 30% of revenues).[502] At the local level, there is an additional municipal franchise fee applicable to electric utilities for the use of municipal public goods to deliver electricity.[503]

6.8.3 Key considerations in changes in the tax rates

Some of the tax rates in Kansas are relatively high compared to a number of the neighboring states included in this Study. However, the implications of lowering tax rates for utilities must be carefully considered, and the pros of lowering taxes must be weighed against the impacts of such measures, as discussed in this section.

6.8.3.1 Advantages

Some supply-side economists argue that economic growth can be most effectively created by lowering taxes.[504] A decrease in taxes would allow households to have a larger after-tax or disposable income than they had before, which would lead to an increase in consumption. Thus, the planned aggregate expenditure would rise, resulting in inventories being lower than planned, thereby a higher output. When output rises, more workers are employed, and more income is generated, causing a second-round increase in consumption, and so on.[505] However, as discussed in the subsequent section, this "boost" to the economy must be weighed against the societal costs of lower taxes.

Theoretically, **a reduction in taxes lowers customer costs** while leaving earnings constant for utilities. Rate regulation allows utilities to charge rates/tariffs based on their revenue requirements to recover the total costs of providing services. Conventionally, the revenue requirement for utilities is calculated by combining operating income requirements and the operating costs associated with providing services to customers. As discussed in Section 1, taxes, among other expenses, are typically embedded in the operating costs. Therefore, a tax cut would

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[500] Texas Comptroller of Public Accounts. "Public Utility Gross Receipts Assessment." Web. Downloaded November 8, 2019. <https://comptroller.texas.gov/taxes/public-utility/>

[501] Texas Comptroller of Public Accounts. "Franchise Tax." Web. Downloaded November 8, 2019 <https://comptroller.texas.gov/taxes/franchise/>

[502] Association of Electric Companies, INC. "State and Local Taxation of the Electric Industry in Texas". Web. 2017. <http://aect.net/documents/2017/AECT%20Taxes%202017.pdf>

[503] See Texas Statutes. *Title II, Subtitle G, Chapter 182, Subchapter B, Section 182.025.* <https://statutes.capitol.texas.gov/Docs/TX/htm/TX.182.htm> and Texas Statutes. *Title II, Subtitle B, Chapter 33, Subchapter A, Section* 33.008. <https://statutes.capitol.texas.gov/Docs/UT/htm/UT.33.htm#33.008>

[504] James D. Gwartney. *Supply-Side Economics.* The Library of Economics and Liberty. Web. Downloaded November 18, 2019. <https://www.econlib.org/library/Enc/SupplySideEconomics.html>

[505] Karl E. Case, Ray C. *Fair. Principles of Macroeconomics.* Third Edition. Prentice-Hall, Inc. 1994.

lower the utilities' operating costs as a reduction in sales and use tax, corporate income tax, and property tax will be passed through to customers in the form of reduced electricity rates on their utility bills, thus making them better off. However, this does not affect the utilities' earnings, as the revenue requirement goes down, the tax gross-up[506] goes down by the exact same amount, which perfectly offsets each other and holds the net income unchanged.

6.8.3.2 Drawbacks

From the state and local governments' perspective:

- **Revenues from taxes for state and local governments will decline** because of tax reductions. To make up for the revenue losses and maintain the fiscal balance, state and local governments may need to restructure taxes and/or raise additional external capital in the following ways:
    - introduce new corrective taxes, for instance, a consumption (excise) tax to balance the government budget;
    - increase personal income taxes (Kansas currently has the 18th lowest rates in the country);[507]
    - issue municipal bonds as a means of day-to-day funding obligations and to finance capital projects; or
    - ask for federal aid.

- **Income tax cuts might not significantly improve economic performance with regards to job creation, economic output, or other metrics**.

From the utilities' perspective:

- Tax cut on corporate income will be **credit negative for utilities,** as a lower tax rate reduces the Earnings Before Interest and Taxes ("EBIT") and Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA").[508] Since the denominator, the interest expense, does not change, tax reductions will lead to a smaller coverage ratio (EBIT or EBITDA/interest expense). As a relevant credit metric, the shrinkage of coverage ratios would potentially lead to downgrading risk in credit ratings and consequently creating upward pressure on utilities' borrowing costs.

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[506] A gross-up is an additional amount of money added to a payment to cover the income taxes the recipient will owe on the payment. <https://www.investopedia.com/terms/g/gross-up.asp>

[507] Business Insider. *State income tax rates across America, ranked from highest to lowest.* Web. October 30, 2019. <https://www.businessinsider.com/state-income-tax-rates-in-every-state-ranked>

[508] Moody's Investors Service. *Tax reform is credit negative for sector, but impact varies by company.* Web. January 24, 2018. <http://www.naruc.org/default/assets/Image/meetings/Winter18/Regulated%20Utilities%20%E2%80%93%20U_S_%20Tax%20Reform%20is%20Credit%20Negative%20for%20Sector%2C%20but%20Impact%20Varies%20by%20Company%20January%2024%2C%202018.pdf>

- **Reduced tax rates will defer cash flows and increase the financial risk for utilities**. As most utilities use accelerated tax depreciation,[509] accelerating cash flows by deferring tax liabilities, they would be subject to the tax normalization.[510] Since the benefits of accelerated depreciation are reduced, utilities would need to re-measure the Accumulated Deferred Income Taxes ("ADIT").[511] ADIT is an interest-free loan that is treated by regulators as either a rate base reduction or as zero cost capital in the ratemaking formula,[512] meaning a tax cut would delay utilities' cash flow and increase their financial risk.[513]

6.8.4 Concluding remarks

As described in the subsections above, Kansas' tax rate on electric utilities is among the highest relative to its neighboring states. Figure 155 exhibits a brief comparison of some key taxes considered in this Study.

As shown in Figure 155, Kansas' rates are higher than the regional average across the three tax categories considered - sales and use tax, corporate income tax, and property tax assessment rate (without considering Texas).

Figure 155. Summary table of key tax rates in Kansas and neighboring states

	AR	CO	IA	KS	MO	ND	OK	SD	TX	Regional average
Sale and use tax (state-level)	6.50%	2.90%	6.00%	6.50%	4.23%	5.00%	4.50%	4.50%	6.25%	5.15%
Corporate income tax - highest bracket (state-level)	6.50%	4.63%	12.00%	7.00%	6.25%	4.31%	6.00%	0.00%	0.00%	5.19%
Property tax assessment rate	20.00%	29.00%	Excise tax	33.00%	n/a	5.00%	22.85%	n/a	100.00%	34.98% (22.97%)

[509] Accelerated depreciation is a depreciation method where an asset loses book value at a faster rate than the traditional straight-line method. In general, this method allows greater deductions in the earlier years and is used to minimize taxable income.

[510] Tax normalization means computing the income tax component as if transactions recognized in each period for ratemaking purposes are also recognized in the same amount in the same period for income tax purposes. Definition from "*18 CFR § 154.305 - Tax normalization*" <https://www.law.cornell.edu/cfr/text/18/154.305>

[511] Deferred income tax is a result of the difference in income recognition between tax laws (i.e. the Internal Revenue Service (IRS)) and accounting methods (i.e. Generally Accepted Accounting Principles ("GAAP")), the difference in depreciation methods used by the IRS and GAAP is the most common cause of deferred income tax.

[512] NARUC – Impact of Tax Reform on Rate Cases. <http://ipu.msu.edu/wp-content/uploads/2018/01/NARUC-Tax-Reform-09132017-Zeldenrust.pdf>

[513] S&P Global Market Intelligence (by Dan Lowrey). *Tax reform bill promises big changes for utilities, power producers.* Web. December 21, 2017. <https://platform.marketintelligence.spglobal.com/web/client?#news/article?id=43004782&KeyProductLinkType=24>

In that respect, several stakeholders have put forward the issue, requesting tax reductions to lessen this cost for ratepayers. However, a tax cut may be a double-edged sword for utilities, significantly influencing their regulated cost of service revenue stream and future utility investment decisions. In general, regulated utilities are required to pass on the tax savings (except for the unrecognized sales and use tax reductions for utility purchase) to customers. Considering the millions of households, such impact can be significant.

Due to tax reductions, utilities might suffer from reduced cashflow and credit deterioration. They would need to have more negotiations with regulators to effectively deal with the negative implications from the tax reform and pass the tangible benefits of tax savings onto ratepayers.

Key takeaways

At face value, higher tax rates imposed on Kansas utilities as compared to the regional averages can result in higher consumer electricity rates.

However, while reducing the tax rates may help improve the competitiveness of utilities by modestly lowering their costs and providing ratepayers with lower electric rates, there can also be socio-economic concerns. For example, state and local governments may suffer from fiscal imbalances, forcing them to increase their revenues from other sources. In addition, a cut in corporate income tax may impair the utilities' credit, exposing them to higher borrowing costs and delaying their cashflows associated with deferred tax liabilities.

Therefore, lowering taxes alone may not be a solution to address the electricity rates competitiveness issue in Kansas without having unintended side effects.

7 Evaluation of options available to KCC and the Kansas Legislature

LEI ultimately reviewed the different options available to the KCC and Kansas legislature based on four criteria:

- achieving regionally competitive electricity rates;
- ensuring utility financial health;
- minimizing implementation costs; and
- incentivizing utility efficiency and performance.

The various legislative and regulatory options were evaluated through the scale of "positive, neutral, and poor." Figure 157 provides a graphical summary of this high-level assessment.

There are several options that would help achieve regionally competitive electric rates for Kansas consumers in the long run, however, the impact on rates would vary among the different options. Additional analysis will be needed to further estimate the cost/benefits of the various options, which are beyond the scope of this Study.

Ensuring the financial health of the utility is not only important to ensure the necessary investments in generation, transmission, and distribution to maintain reliable service, but it can also help lower costs for consumers by lowering financing costs for the utilities. Various PBR mechanisms can help in that regard by offering additional returns to the utility when meeting certain objectives set by the regulators based on state policy or decoupling revenues from sales, thereby reducing variability. EDR mechanisms can also help increase overall load levels, leading to increased revenues for the utility over the long term.

Almost all the options would entail implementation costs to various degrees. These costs could be incurred by the utilities and/or the regulator and may include costs associated with conducting the necessary studies, for stakeholder engagement, for additional personnel, or for new infrastructure.

The utilities' efficiency and performance could be improved through the implementation of various levels of PBR mechanisms or through the introduction of retail competition. This outcome could be achieved under a PBR regime if targets that are set for efficiency and productivity provide balanced rewards for consumers as well as the utilities. Retail competition and deregulation of the generation sector would force utilities to improve their performance in order to stay competitive.

Figure 156. Evaluation criteria

Figure 157. High-level evaluation of options

	Regionally competitive electricity rates	Ensuring utility financial health	Minimizing implementation costs	Utility efficiency and performance
1) Management of capex and opex	↑		↓	
2) Performance-based regulation	↑	↑	↓	↑
3) Economic development rates	↑	↑	↓	
4) Retail competition	↑	↓	↓	↑
5) Investments in energy efficiency and renewables	↑		↓	
6) Securitized ratepayer-backed bonds	↑		↓	
7) SPP participation	↑		↓	
8) Review of tax rates	↑		↓	

Positive impact ↑

Negative impact ↓

Management of capital and operating expenditures

- ***Regionally competitive electricity rates:*** Notably, a state energy plan would outline state policy priorities and therefore provide high-level guidance for utility investments. With these legislative priorities established, the regulator has several tools to ensure cost-effective investments and operational expenditures, such as mandating IRPs. Other regulatory mechanisms that would allow for improved management of capex and opex include full, non-settled rate cases at least once per decade allowing for a discovery process and the setting of precedent on rate-setting mechanisms; the deployment of a

competitive procurement framework to leverage competition for the construction of new assets; deploying asset management strategies, which would increase insight into the state of grid systems and help reduce maintenance and capital costs; or adopting a totex approach to calculating utilities' revenue requirement as part of a PBR framework.

- ***Implementation costs:*** The capex and opex management solutions outlined in this report require modest time and effort to implement, such as for instance, the creation of a state energy plan. Utilities typically already create their own IRPs, so additional costs would be mostly associated with the regulatory review of these plans. Creating a competitive procurement framework would similarly entail costs associated with the regulatory process for its establishment. Finally, the totex approach and deployment of asset management strategies would likely be more expensive than the other methods, due to additional required involvement from regulators, utilities, and consultants.

PBR

- ***Regionally competitive electricity rates:*** PBR should be designed to better align incentives for the utilities with those of customers, resulting in lower rates over time than they would be with a traditional COS approach. Additionally, the reduced regulatory burden under PBR allows utilities to respond more quickly to technological and competitive challenges, which would also contribute to lowering rates.

- ***Utilities' financial health:*** PBR can help utilities through lowering administrative and regulatory costs due by reducing the frequency of rate case proceedings, leading to an overall reduction in the regulatory burden in comparison to a COS framework. While utilities may be concerned that their financial viability could be undermined if there are substantial capex requirements, this can be addressed by prescribing forward capital planning, incorporating adjustment factors within the PBR formula to address capital cost issues, or otherwise modifying the PBR design. PBR will have a net positive impact as long as rewards and savings from efficiency and productivity gains are balanced, considering both utility's financial health and consumer benefits.

- ***Implementation costs:*** Implementation of a PBR framework requires regulatory proceedings involving all stakeholders, although the extent of the proceedings will depend on the scope of the envisioned mechanisms. While "light" PBR mechanisms can be relatively straightforward to add to the current regulatory framework, a more comprehensive PBR implementation is more involved, for instance requiring efforts a regulatory proceeding to determine the appropriate PBR mechanisms and formulas to implement. PBR benefits from regular communication between the regulators and stakeholders, as well as workshops and technical conferences to familiarize stakeholders with the approach. Since PBR is inherently improved by data quality, there are additional costs associated with requiring reliable, comparable, and accurate data and forecasting methods.

- ***Utility efficiency and performance:*** PBR provides strong incentives for utilities to improve service and increase productivity by allowing them to directly derive a significant financial benefit from doing so. PBR allows for utility revenues to be adjusted based on performance, ultimately motivating utilities to control costs and deliver good service. Although ratepayers and regulators may fear that PBR's focus on incentives for cost-cutting will lead to poor quality of service, it is now common practice to include performance standards in the PBR formula to ensure service improvement. By moving away from the capital maximization objectives typical of COS regulation, PBR shifts the focus from cost accounting to productivity analysis in a way that provides superior performance incentives leading to an overall improvement in service.

Economic Development Rates

- ***Regionally competitive electricity rates:*** Economic development rates can help in lowering electricity rates over the long term by attracting large customers, expanding the customer base, thus sharing the fixed costs of providing the electric service over a wider base. As discussed previously, however, care must be taken in not shifting the cost burden or otherwise harming existing customers.

- ***Utilities' financial health:*** EDRs are designed to attract additional load to a utility's service territory from commercial or industrial customers. This additional load stimulates sales and enhances revenue, thus improving the utility's financial viability.

- ***Implementation costs:*** While the implementation of EDRs is not particularly complicated, they still represent lower revenues from new load customers with respect to rates paid by existing customers.

Retail competition

- ***Regionally competitive electricity rates:*** Retail competition is likely to make electricity rates more competitive regionally. In most jurisdictions, retail competition has enabled savings on energy bills because retailers focus on offering competitively priced power supply. This is likely to have a particularly strong impact in the C&I segment, potentially offering economic development benefits.

- ***Utilities' financial health:*** Utility still own legacy generation assets, which could become stranded if customers, especially large commercial customers, switch to a competitive supplier to obtain lower cost power supply. The impact utility's financial health could be reduced, however, if retail competition was phased in over time and utilities were allowed to recover the stranded costs, although the benefits for consumers would then be mitigated.

- ***Implementation costs:*** The process for implementing retail competition is quite involved, including, for instance, the necessary legislative and regulatory proceedings to create the framework as well as implementation costs for IT systems or billing systems. The regulator will also need to run outreach and education campaigns to prepare customers for retail competition and manage a price-to-compare website where customers can check their pricing options.

- ***Utility's efficiency and performance:*** Over the long term, retail competition could be beneficial for utilities if they are made to operate in a competitive market.

Investments in energy efficiency and renewables

- ***Regionally competitive electricity rates:*** Incentives for customers to invest in energy efficiency can lead to reduced costs for consumers, although not all programs are cost-effective. As such energy efficiency must be analyzed together with other methods of meeting load requirements as part of a long-term planning effort by the utilities in order to ensure that these programs provide overall benefits to Kansas consumers.

- ***Implementation costs:*** The costs of investing in energy efficiency need to be compared against expected benefits and unintended consequences and analyzed holistically, so that clear benefits for consumers can be expected. Similarly, incentives for renewable generation must be balanced against the expected benefits, considering the current economic context where those resources are beginning to compare favorably with other sources of generation on a levelized cost of energy basis.

Securitization

- ***Regionally competitive electricity rates:*** Given that the cost/benefit analysis of uneconomic asset retirement shows clear benefits to consumers, securitization can be an effective way to reduce the costs of stranded assets as compared to the asset remaining in utilities' rate-bases.

- ***Implementation costs:*** Securitization requires time and effort from the legislature to create enabling legislation, as well as for structuring a special purpose vehicle, consulting with financial advisors, and issuing bonds in a capital market. Each of these steps requires time and an associated expense that would create implementation costs.

SPP Participation

- ***Regionally competitive electricity rates:*** Through additional advocacy for changes in the method for allocation of transmission costs among a greater number of customers outside Kansas, the transmission costs allocated to Kansas customers could be lower over the long term than they would otherwise be. Increased advocacy can also ensure that Kansas

customers are not at a disadvantage when changes to SPP's OATT and market rules are discussed in stakeholder committees.

- ***Implementation costs:*** There may be some additional impact on implementation costs if the state decides to increase support for consumer participation at SPP committees and working groups.

Tax rates

- ***Regionally competitive electricity rates:*** In general, regulated utilities are required to pass on the tax savings to customers so that a tax cut could lower utilities' expenses albeit very modestly. Lower expenses would lead to lower electricity rates, ultimately improving customer welfare. However, the significance of the effect on rate change will depend on each utility's economic situation and decision. Utilities may use some of these savings to hedge future rate increases, accelerate power plant retirements, facilitate planned system improvements, and conduct required maintenance.

- ***Implementation costs:*** A reduction in tax rates for utilities can ultimately raise costs elsewhere since the public entities will look at other means of increasing the missing revenues from utility taxes.

Ultimately, there is no single easy fix that would reduce electricity rates. Kansas needs to adopt a portfolio approach that would gradually achieve regionally competitive electricity rates over time. LEI recommends the following near-term steps in order to help achieve that objective:

- **State energy plan –** The Kansas legislature should create an energy plan for the state. The plan need not be overly long or complicated, but it can help the state determine what its energy goals are, how to achieve them, and at what cost. The state policy objectives should extend to all entities serving electric customers in the state, including utilities, munis, and co-ops.

- **Integrated Resource Plans –** Regulated utilities should be required to submit IRPs at regular intervals, detailing their plan to meet load requirements over the forecast horizon. All methods of meeting future load requirements (including different technologies, ownership arrangements, or energy efficiency initiatives) should be analyzed to determine the most cost-effective solutions that would also meet the state policy objectives. Competitive procurement for new large generation or transmission assets should also be considered. Non-regulated utilities should also be required to submit IRPs, or at least demonstrate that their supply portfolio meets the state policy objectives.

- **Performance-Based Regulation –** The Kansas legislature should consider allowing the KCC to explore the development of PBR mechanisms which, over time, could evolve into a more comprehensive PBR framework. Initial implementation, however, needs

not be complicated but should, at a minimum, set targets to incentivize utility efficiency and align utility incentives with customer benefits and state policy objectives.

- **Retirement and securitization of uneconomic assets –** The Kansas legislature should establish a framework allowing for the securitization of uneconomic assets if the cost/benefit analysis of asset retirement demonstrates clear benefits to consumers. However, care should be taken in allowing the utility to grow its rate base following the securitization process, as the utility rate base needs to be stay commensurate with the needs of consumers.

8 List of acronyms

ACA	Annual Cost Adjustment
ACEEE	American Council for Energy-Efficient Economy
ADIT	Accumulated Deferred Income Taxes
AIFI	Average Interruption Frequency Index
AMI	Automatic Meter Infrastructure
AMR	Automatic Meter Reading
APSC	Arkansas Public Service Commission
ATRR	Annual Transmission Revenue Requirement
AVTR	Ad Valorem Tax Rider
BA	Balancing Authorities
BPU	Kansas City Board of Public Utilities
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
Capex	capital expenditure
CaSPM	California Standard Practice Manual
CAWG	Cost Allocation Working Group
CBA	Consolidated Balancing Authority
CCA	Community choice aggregation
CEO	Chief Executive Officer
CIP	Capital Improvement Plans
CMP	Central Maine Power
CO	Colorado
COS	Cost-of-Service
COSS	Cost-of-Service Study
CURB	Citizen's Utility Ratepayer Board
DEF	Duke Energy Florida, LLC
DOE	Department of Energy
DSC	Debt Service Coverage
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortization
ECA	Energy Cost Adjustment
ECM	Efficiency carry-over mechanism
ECRR	Environmental Cost Recovery Rider
EDC	Electric distribution company
EDE	Empire District Electric
EDI	Economic development incentive
EDR	Economic development rates or riders
EER	Energy Efficiency Rider
EERS	Energy Efficiency Resource Standard
EGS	Electric generation supplier
ELL	Entergy Louisiana, LLC
EIA	Energy Information Administration
EPA	Environmental Protection Agency

ERC	Energy Rate Component
ERCOT	Electric Reliability Council of Texas
ESC	Environmental Surcharge
ESCO	Energy Service Companies
ESM	Earnings sharing mechanism
ESWG	Economic Studies Working Group
FERC	Federal Energy Regulatory Commission
FPSC	Florida Public Service Commission
FTE	Full Time Equivalent
FTR	Financial Transmission Rights
G&T	Generation and Transmission
GT	Gas Turbine
HECO	Hawaiian Electric Company
HIIT	Holistic Integrated Tariff Team
I-X	Inflation factor less productivity factor
IA	Iowa
ICC	Illinois Commerce Commission
IM	Integrated Marketplace
IOU	Investor Owned Utility
IPP	Independent power producers
IRP	Integrated Resource Planning
IRS	Internal Revenue Service
ISO	Independent System Operator
K-EBRA	Kansas Energy Bill Reduction Assistance bonds
KCC	Kansas Corporation Commission
KCP&L	Kansas City Power & Light
KEC	Kansas Electric Cooperatives
KEEIA	Kansas Energy Efficiency Investment Act
KEPCo	Kansas Electric Power Cooperative, Inc.
KGE	Kansas Gas and Electric
KIC	Kansas Industrial Consumers group
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
KS	Kansas
LCC	Legislative Coordinating Council
LEI	London Economics International
LPSC	Louisiana Public Service Commission
LRAM	Lost Revenue Adjustment Mechanism
LRS	Load Ratio Share
MDU	Montana-Dakota Utilities Co.
MEEIA	Missouri Energy Efficiency Investment Act
MA	Membership agreement
MO	Missouri
MOPC	Market Operations and Policy Committee
MWG	Market Working Group
ND	North Dakota

NERC	North American Electric Reliability Corporation
NESP	National Efficiency Screening Project
NSPM	National Standard Practice Manual
NTG	Net-to-gross ratio
NYSE	New York Stock Exchange
O&M	operations and maintenance
OATT	Open Access Transmission Tariff
OCC	Oklahoma Corporation Commission
OEB	Ontario Energy Board
OK	Oklahoma
OMPA	Oklahoma Municipal Power Authority
Opex	operating expenditure
OPPD	Omaha Public Power District
ORWG	Operating Reliability Working Group
PAC	Program Administrator Cost Test
PCT	Participant Cost Test
PBR	Performance-Based Regulation/Ratemaking
PILOT	Payments-in-lieu-of-taxes
PIM	Performance incentive mechanisms
POLR	Providers of last resort
PPA	Power purchase agreements
PSC	Public Service Commission
PTB	Price to beat
PTC	Price to compare
PTC	Production tax credit
PUC	Public Utility Commission
R&R	Report and Recommendation
REC	Renewable Energy Certificates
REP	Retail electric provider
RES	Retail electric suppliers
RESA	Retail Electric Suppliers Act
RIIO	Revenue = Incentives, Innovation, and Outputs
RIM	Ratepayer Impact Measure
ROE	Return on Equity
RMS	Request Management System
ROR	Rate of Return
RRR	Revenue Requirements and Rates
RSC	Regional State Committee
RTO	Regional Transmission Operator
RTWG	Regional Tariff Working Group
RUS	Rural Utilities Service
RVT	Resource value test
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEIA	Solar Energy Industries Association
SB	Senate Bill

SCT	Societal Cost Test
SD	South Dakota
SDG&E	San Diego Gas and Electric
SPC	Strategic Planning Committee
SPP	Southwest Power Pool
SPV	Special Purpose Vehicle
TDC	Transmission Delivery Charge
TFP	Total factor productivity
TFR	Transmission Formula Rates
TIER	Times Interest Earned Ratio
Totex	Total expenditure
TRC	Total Resource Cost
TWG	Transmission Working Group
TX	Texas
UBP	Uniform Business Practices
UCT	Utility/Programs Administrator
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital
WVPSC	West Virginia Public Service Commission

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10 Appendix A: List of co-ops included in the calculation of average electricity prices

No.	Cooperative	State
1	C & L Electric Cooperative Corp.	AR
2	First Electric Cooperative Corporation	AR
3	Mississippi County Electric Cooperative, Inc.	AR
4	North Arkansas Electric Cooperative, Inc.	AR
5	Ouachita Electric Coop Corp	AR
6	Petit Jean Electric Cooperative Corp.	AR
7	South Central Ark Electric Cooperative Inc.	AR
8	Woodruff Electric Cooperative Corporation	AR
9	Grand Valley Rural Power Lines Inc	CO
10	Gunnison County Electric Association Inc	CO
11	Holy Cross Energy	CO
12	Intermountain Rural Elec Assn	CO
13	K C Electric Assn	CO
14	La Plata Electric Assn Inc	CO
15	Morgan County Rural Electric Association	CO
16	Mountain Parks Electric, Inc.	CO
17	Mountain View Electric Association, Inc.	CO
18	Poudre Valley R E A Inc	CO
19	San Isabel Electric Assn, Inc	CO
20	San Luis Valley Rural Electric Cooperative Inc	CO
21	San Miguel Power Assn, Inc	CO
22	Sangre De Cristo Elec Assn Inc	CO
23	Southeast Colorado Power Association	CO
24	United Power, Inc.	CO
25	White River Electric Association, Inc.	CO
26	Access Energy Cooperative	IA
27	Allamakee-Clayton Electric Cooperative Inc.	IA
28	Butler County Rural Electric Cooperative	IA
29	Chariton Valley Electric Cooperative, Inc.	IA
30	Clarke Electric Cooperative Inc.	IA
31	Consumers Energy Cooperative	IA
32	Farmers Electric Cooperative, Inc.	IA
33	Farmers Electric Cooperative, Inc. - Greenfield - IA	IA
34	Franklin Rural Electric Cooperative	IA
35	Grundy County Rural Electric Cooperative	IA
36	Guthrie County Rural E C A	IA
37	Harrison County Rural Electric Cooperative	IA
38	Iowa Lakes Electric Cooperative, Inc.	IA
39	Linn County Rural Electric Cooperative Association	IA
40	Lyon Rural Electric Cooperative	IA
41	Maquoketa Valley Electric Cooperative	IA
42	Midland Power Cooperative	IA
43	Nishnabotna Valley R E C	IA
44	North West Rural Electric Cooperative	IA
45	Osceola Electric Cooperative Inc.	IA
46	Pella Cooperative Elec Assn	IA
47	Prairie Energy Cooperative	IA
48	Raccoon Valley Electric Cooperative	IA
49	Southern Iowa Electric Cooperative, Inc.	IA
50	T I P Rural Electric Coop	IA

No.	Cooperative	State
51	Western Iowa Power Cooperative	IA
52	Woodbury County Rural E C A	IA
53	Bluestem Electric Cooperative, Inc.	KS
54	Brown-Atchison Electric Co-operative Association, Inc.	KS
55	Butler Rural El Coop Assn Inc	KS
56	Caney Valley Electric Cooperative Association, Inc.	KS
57	CMS Electric Cooperative Inc.	KS
58	Flint Hills Rural Electric Cooperative Association Inc	KS
59	FreeState Electric Cooperative, Inc.	KS
60	Heartland Rural Electric Cooperative, Inc.	KS
61	Lane-Scott Electric Cooperative Inc.	KS
62	Lyon-Coffey Electric Cooperative, Inc.	KS
63	Midwest Energy, Inc.	KS
64	Nemaha-Marshall E C A Inc	KS
65	Ninnescah Rural Electric Cooperative	KS
66	Pioneer Electric Cooperative, Inc.	KS
67	Prairie Land Electric Cooperative, Inc.	KS
68	Radiant Electric Cooperative Inc.	KS
69	Rolling Hills Electric Cooperative, Inc.	KS
70	Sedgwick County Electric Cooperative Association Inc.	KS
71	Sumner-Cowley Electric Cooperative, Inc.	KS
72	Twin Valley Electric Cooperative Inc.	KS
73	Victory Electric Cooperative Association Inc.	KS
74	Western Cooperative Electric Association, Inc.	KS
75	Macon Electric Cooperative, Inc.	MO
76	Barry Electric Cooperative	MO
77	Barton County Electric Coop., Inc.	MO
78	Black River Electric Cooperative	MO
79	Boone Electric Coop.	MO
80	Central Missouri Electric Cooperative Inc.	MO
81	Citizens Electric Corporation	MO
82	Cuivre River Electric Cooperative, Inc.	MO
83	Farmers Electric Cooperative Inc. - MO	MO
84	Gascosage Electric Cooperative	MO
85	Howard Electric Cooperative	MO
86	Howell-Oregon Electric Cooperative, Inc.	MO
87	Intercounty Electric Cooperative Association	MO
88	Laclede Electric Cooperative	MO
89	Lewis County Rural E C A	MO
90	Missouri Rural Electric Cooperative	MO
91	New-Mac Electric Cooperative Inc.	MO
92	North Central Missouri Electric Cooperative Inc.	MO
93	Osage Valley Electric Cooperative, Inc.	MO
94	Ozark Border Electric Cooperative	MO
95	Ozark Electric Cooperative Inc.	MO
96	Pemiscot-Dunklin Electric Cooperative Inc	MO
97	Platte-Clay Electric Cooperative, Inc.	MO
98	Ralls County Electric Cooperative	MO
99	Sac-Osage Electric Cooperative Inc.	MO
100	Se-Ma-No Electric Cooperative	MO

No.	Cooperative	State
101	SEMO Electric Cooperative	MO
102	Southwest Electric Cooperative, Inc.	MO
103	Three Rivers Electric Cooperative	MO
104	Tri-County Electric Cooperative Assn - MO	MO
105	Webster Electric Cooperative	MO
106	West Central Electric Coop Inc	MO
107	White River Valley Electric Cooperative, Inc.	MO
108	Burke-Divide Electric Cooperative Inc.	ND
109	Capital Electric Cooperative Inc.	ND
110	Cass County Electric Cooperative Inc.	ND
111	Dakota Valley Electric Cooperative, Inc.	ND
112	KEM Electric Cooperative Inc.	ND
113	McLean Electric Cooperative.	ND
114	Mor-Gran-Sou Electric Cooperative.	ND
115	Mountrail-Williams Electric Cooperative	ND
116	Nodak Electric Cooperative, Inc.	ND
117	North Central Electric Cooperative - ND	ND
118	Northern Plains Electric Cooperative	ND
119	Roughrider Electric Cooperative, Inc.	ND
120	Slope Electric Cooperative Inc.	ND
121	Verendrye Electric Cooperative Inc.	ND
122	Canadian Valley Electric Cooperative, Inc.	OK
123	Central Rural Electric Cooperative, Inc.	OK
124	Choctaw Electric Coop Inc	OK
125	Cimarron Electric Cooperative	OK
126	Indian Electric Cooperative, Inc.	OK
127	Kay Electric Coop	OK
128	Kiamichi Electric Coop Inc	OK
129	Lake Region Electric Cooperative	OK
130	Northeast Oklahoma El Coop Inc	OK
131	Northfork Electric Cooperative Inc.	OK
132	Northwestern Electric Cooperative Inc.	OK
133	Oklahoma Electric Cooperative, Inc.	OK
134	People's Electric Cooperative	OK
135	Red River Valley Rural Elec Assn	OK
136	Rural Electric Cooperative, Inc.	OK
137	Southeastern Electric Cooperative Inc. - OK	OK
138	Verdigris Valley Electric Cooperative, Inc.	OK
139	Black Hills Electric Cooperative, Inc.	SD
140	Bon Homme Yankton Electric Association, Inc.	SD
141	Butte Electric Cooperative, Inc.	SD
142	Cam Wal Electric Cooperative Inc.	SD
143	Central Electric Cooperative, Inc.	SD
144	Charles Mix Electric Assn, Inc	SD
145	Clay-Union Electric Corp	SD
146	Codington-Clark Electric Cooperative, Inc.	SD
147	FEM Electric Assn Inc	SD
148	Lake Region Electric Assn Inc	SD
149	Moreau-Grand Electric Cooperative.	SD
150	Northern Electric Cooperative Inc. - SD	SD
151	Oahe Electric Cooperative Inc.	SD
152	Rosebud Electric Cooperative Inc.	SD
153	Southeastern Electric Cooperative, Inc.	SD
154	Union County Electric Cooperative Inc.	SD

No.	Cooperative	State
155	West Central Electric Cooperative Inc.	SD
156	West River Electric Assn Inc	SD
157	Whetstone Valley Electric Cooperative Inc.	SD
158	Bailey County Electric Cooperative Association	TX
159	Bandera Electric Cooperative, Inc.	TX
160	Bartlett Electric Cooperative Inc.	TX
161	Big Country Electric Cooperative, Inc.	TX
162	Bluebonnet Electric Cooperative, Inc.	TX
163	Bowie-Cass Electric Cooperative Inc.	TX
164	Central Texas Electric Cooperative Inc.	TX
165	Cherokee County Electric Cooperative Association	TX
166	Coleman County Electric Cooperative, Inc.	TX
167	Fannin County Electric Coop	TX
168	Farmers Electric Coop, Inc -TX	TX
169	Fayette Electric Coop Inc	TX
170	Fort Belknap Electric Cooperative Inc	TX
171	Grayson-Collin Electric Cooperative, Inc.	TX
172	Greenbelt Electric Cooperative Inc.	TX
173	Guadalupe Valley Electric Cooperative, Inc.	TX
174	Hamilton County Electric Cooperative Association	TX
175	HILCO Electric Cooperative, Inc.	TX
176	Houston County Electric Cooperative Inc.	TX
177	Jackson Electric Cooperative Inc. TX	TX
178	Jasper-Newton Electric Cooperative, Inc.	TX
179	Karnes Electric Cooperative Inc.	TX
180	Lamar County Electric Cooperative Association	TX
181	Lamb County Electric Cooperative, Inc.	TX
182	Lighthouse Electric Cooperative Inc.	TX
183	Lyntegar Electric Cooperative, Inc.	TX
184	Magic Valley Electric Cooperative, Inc.	TX
185	Medina Electric Cooperative, Inc.	TX
186	Mid-South Synergy Inc	TX
187	Navarro County Electric Cooperative Inc.	TX
188	Navasota Valley Electric Cooperative, Inc.	TX
189	North Plains Electric Cooperative, Inc.	TX
190	Nueces Electric Cooperative Inc.	TX
191	Pedernales Electric Cooperative Inc.	TX
192	Rita Blanca Electric Cooperative Inc.	TX
193	Rusk County Electric Cooperative, Inc.	TX
194	Sam Houston Electric Cooperative, Inc.	TX
195	San Bernard Electric Cooperative, Inc.	TX
196	San Patricio Electric Cooperative Inc.	TX
197	South Plains Electric Cooperative, Inc.	TX
198	Southwest Texas Electric Cooperative Inc	TX
199	Swisher Electric Cooperative, Inc.	TX
200	Taylor Electric Cooperative Inc	TX
201	Tri-County Electric Cooperative, Inc.	TX
202	Trinity Valley Elec Coop, Inc	TX
203	United Electric Cooperative Services Inc - TX	TX
204	Upshur Rural Electric	TX
205	Victoria Electric Cooperative, Inc.	TX
206	Wharton County Elec Coop Inc	TX
207	Wise Electric Cooperative Inc	TX
208	Wood County Electric Cooperative Inc.	TX

11 Appendix B: List of municipal utilities included in the calculation of average electricity prices

No.	Municipal utility	State
1	Benton City of AR	AR
2	Bentonville City of	AR
3	Clarksville Light & Water Co	AR
4	Hope City of AR	AR
5	Jonesboro City of (AR)	AR
6	North Little Rock City of	AR
7	Osceola City of - AR	AR
8	Paragould Light and Water Commission	AR
9	Siloam Springs City of	AR
10	West Memphis City of	AR
11	Aspen City of	CO
12	Colorado Springs Utilities	CO
13	Fort Collins City of	CO
14	Fort Morgan City of	CO
15	Fountain City of	CO
16	Frederick Town of	CO
17	Glenwood Springs City of	CO
18	Gunnison City of	CO
19	Longmont City of	CO
20	Loveland City of	CO
21	Algona City of	IA
22	Atlantic Municipal Utilities	IA
23	Bloomfield City of	IA
24	Board of Water Electric & Communications	IA
25	Cedar Falls Utilities	IA
26	Forest City City of	IA
27	Graettinger City of	IA
28	Greenfield City of IA	IA
29	Grundy Center Municipal Light & Power Dept.	IA
30	Harlan City of	IA
31	Hawarden City of	IA
32	Hinton City of	IA
33	Independence City of IA	IA
34	Indianola Municipal Utilities	IA
35	Lake Mills City of IA	IA
36	Lamoni City of	IA
37	Laurens City of IA	IA
38	Lenox City of	IA
39	Manilla Town of	IA
40	Manning City of	IA
41	Maquoketa City of	IA
42	Milford City of IA	IA
43	Montezuma City of IA	IA
44	Mt Pleasant City of IA	IA
45	New Hampton City of	IA
46	Onawa City of	IA
47	Orange City City of	IA
48	Osage City of	IA
49	Pella City of	IA
50	Preston City of	IA
51	Remsen City of	IA
52	Rock Rapids Municipal Utility	IA
53	Sanborn City of	IA
54	Sergeant Bluff City of	IA
55	Sibley City of	IA
56	Sioux Center City of	IA
57	Spencer City of IA	IA
58	Story City City of	IA
59	Tipton City of IA	IA
60	Vinton City of IA	IA
61	Waverly Communications Utility	IA
62	Webster City City of	IA
63	West Liberty City of	IA
64	Wilton City of	IA
65	Winterset City of	IA
66	Augusta City of KS	KS
67	Baldwin City City of	KS
68	Beloit City of	KS
69	Burlington City of KS	KS
70	Chanute City of	KS
71	Clay Center City of	KS
72	Coffeyville City of	KS
73	Colby City of	KS
74	Garden City City of	KS
75	Gardner City of	KS
76	Garnett City of	KS
77	Girard City of	KS
78	Goodland City of	KS
79	Holton City of	KS
80	Hugoton City of	KS
81	Iola City of	KS
82	Kingman City of	KS
83	Larned City of	KS
84	McPherson City of	KS
85	Moundridge City of	KS
86	Mulvane City of	KS
87	Neodesha City of	KS
88	Osage City City of	KS
89	Osawatomie City of	KS
90	Ottawa City of	KS
91	Pratt City of	KS
92	Russell City of KS	KS
93	Sabetha City of	KS
94	Seneca City of KS	KS
95	Wamego City of	KS
96	Wellington City of KS	KS
97	Winfield City of	KS
98	Ava City of	MO
99	Cameron City of	MO
100	Carthage City of	MO

No.	Municipal utility	State
101	Chillicothe Municipal Utilities	MO
102	City Utilities of Springfield	MO
103	Farmington City of MO	MO
104	Fulton City of MO	MO
105	Hannibal City of	MO
106	Harrisonville City of	MO
107	Independence City of MO	MO
108	Jackson City of MO	MO
109	Kennett City of	MO
110	Kirkwood City of	MO
111	Lamar City of MO	MO
112	Lebanon City of MO	MO
113	Macon Municipal Utilities	MO
114	Marshall City of MO	MO
115	Monett City of	MO
116	Mount Vernon City of	MO
117	Nixa City of	MO
118	Poplar Bluff City of	MO
119	Rolla City of	MO
120	Sikeston City of	MO
121	Sullivan City of MO	MO
122	Trenton Municipal Utilities	MO
123	West Plains City of	MO
124	Lakota City of	ND
125	Valley City City of	ND
126	Claremore City of	OK
127	Grand River Dam Authority	OK
128	Mangum City of	OK
129	Miami City of	OK
130	Pawhuska City of	OK
131	Ponca City City of	OK
132	Prague Public Works Authority	OK
133	Pryor City of	OK
134	Sallisaw City of	OK
135	Stillwater Utilities Authority	OK
136	Stilwell City of	OK
137	Tahlequah Public Works Authority	OK
138	Wagoner Public Works Authority	OK
139	Beresford City of	SD
140	Brookings City of	SD
141	Flandreau City of	SD
142	Fort Pierre City of	SD
143	Madison City of SD	SD
144	Miller City of	SD
145	Pierre City of	SD
146	Sioux Falls City of	SD
147	Vermillion City of SD	SD
148	Volga City of	SD
149	Watertown City of SD	SD
150	Winner Municipal Utility	SD

No.	Municipal utility	State
151	Austin Energy	TX
152	Boerne City of	TX
153	Brenham City of	TX
154	Brownsville Public Utilities Board	TX
155	Bryan City Of	TX
156	City Public Service of San Antonio	TX
157	College Station City of	TX
158	Floresville City of	TX
159	Fredericksburg City of TX	TX
160	Garland City of	TX
161	Georgetown City of TX	TX
162	Greenville City of	TX
163	Jasper City of TX	TX
164	Kerrville Public Utility Board	TX
165	Lampasas City of	TX
166	Liberty City of	TX
167	Lockhart City of	TX
168	Lubbock City of	TX
169	New Braunfels City of	TX
170	San Marcos City of	TX
171	Seguin City of	TX
172	Weatherford Mun Utility System	TX

12 Appendix C: Overview of comparable states

12.1 Arkansas

12.1.1 Overview

Arkansas was selected as a comparator state because the bulk of electricity serving consumers stems from the state's large coal and gas fleet, similar to Kansas. Of all the states reviewed in this Study, Arkansas is the smallest in terms of land area, with abundant natural gas reserves and thermal resources. As a result, the state produces more energy than it consumes.[514]

The state's installed capacity is dominated by natural gas (47%) and coal (40%). The majority of electric consumption in Arkansas comes from the industrial and residential customer segments, each consuming 37% of electricity generated in the state.[515] A summary of key electricity data for Arkansas is shown in Figure 158 below.

Figure 158. Snapshot of Arkansas' electricity industry

Key facts (2017 unless specified)	
Installed capacity	14,642 MW
Demand	46.1 TWh
Load growth (2013-2017)	-0.30%
Transmission lines	3,730 miles
Population (2018)	3.01 million
GDP growth (nominal, 2014-2018)	2.3%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

514 "Arkansas State Profile and Energy Estimates Analysis." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AR>

515 Ibid.

12.1.2 Institutional and legal framework

12.1.2.1 Utilities

There are 24 regulated electric utilities in Arkansas, comprising four IOUs, one generation and transmission co-op, 17 distribution co-ops, and two RTOs.[516] Similar to Kansas, there is no retail choice in Arkansas, and all distribution utilities have exclusive franchise over their service territory. The principal electricity providers in Arkansas are as follows:[517]

- Entergy Arkansas, LLC;
- Arkansas Electric Cooperative Corporation;
- Southwestern Electric Power Company; and
- Oklahoma Gas & Electric Corporation.

12.1.2.2 State energy office

The **Arkansas Energy Office** ("AEO"), which was first established within the Arkansas Economic Development Commission in 1981 under Act 7, was transferred to the state's Department of Environmental Quality in 2017.[518][519] The AEO currently lists seven staff members on its website, ranging from Associate Director, Manager, Program Assistant to Engineer.[520]

The AEO's mission centers on the promotion of energy efficiency, clean technology, and sustainable strategies, which are designed to "*encourage economic development, energy security and the environmental well-being*" of its citizens.[521] The AEO's core programs focus on "*home energy scores, energy performance contracting, partnerships to reduce petroleum consumption for transportation, energy technology loans, weatherization assistance, and other strategies,*" a sample of which are summarized in the textbox below.[522]

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[516] "Electric Section." *Arkansas Public Service Commission*. <http://www.apscservices.info/electric.asp>

[517] "Electric Utilities." *Arkansas Economic Development Commission.* <http://www.apscservices.info/electric.asp>

[518] Arkansas Public Service Commission. *Rebuttal Testimony of Chris Benson*. September 18, 2009.

[519] Arkansas State Legislature. *Act Number 271.* 2017.

[520] "Arkansas Energy Office." *Arkansas Department of Environmental Quality.* <http://www.adeq.state.ar.us/energy/>

[521] Ibid.

[522] Ibid.

AEO programming

- **Energy codes,** which establish energy efficient building codes and standards for residential and commercial buildings and set a requirement for state government buildings to exceed these standards by 10%.
- **Weatherization Assistance Program ("WAP"),** which weatherizes homes by installing energy efficiency upgrades in qualifying low-income homes. This weatherization service is conducted by seven service providers active throughout the state.
- **Arkansas energy performance contracting,** which is a financing mechanism whereby energy efficiency improvements are paid back through annual energy savings.

Source: "Arkansas Energy Office." *Arkansas Department of Environmental Quality.* <http://www.adeq.state.ar.us/energy/>

12.1.2.3 Regulator

The **Arkansas Public Service Commission** ("APSC") currently regulates public utilities in the state, providing service in the following areas: electricity, natural gas, water, telephone, as well as pipeline safety.[523] The APSC's mandate is enabled by Title 23 of the Arkansas Code – Public Utilities and Regulated Industries.[524] This jurisdiction covers 24 electric utilities in the state but does not cover munis, public power agencies, or exempt wholesale generators (namely IPPs).[525]

The APSC was first established in 1919 as the successor to the Arkansas Railroad Commission, which was created in 1899 pursuant to an amendment to Ark. Const. Art. 17, Section 10.[526] The Commission's primary mission is to ensure that the services provided by regulated utilities are safe and adequate, and that the rates charged are just and reasonable. The APSC is served by three Governor-appointed Commissioners who serve overlapping six-year terms.[527]

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[523] "Home Page." *Arkansas Public Service Commission.* <http://www.apscservices.info/>

[524] "Title 23. Public Utilities and Regulated Industries." *Lexis Advance.* <https://advance.lexis.com/container?config=00JAA3ZTU0NTIzYy0zZDEyLTRhYmQtYmRmMS1iMWIxNDgxYWMxZTQKAFBvZENhdGFsb2cubRW4ifTiwi5vLw6cI1uX&crid=70c87cc1-511c-4f0a-93c9-01c1b83b4864&prid=f19f42f5-0ed4-40d4-b461-a0ca90071dc5>

[525] "Electric Section." *Arkansas Public Service Commission*. <http://www.apscservices.info/electric.asp>

[526] "Commission History." *Arkansas Public Service Commission.* <http://www.apscservices.info/commission-history.asp>

[527] Arkansas Public Service Commission. *Annual Report.* 2018.

12.1.3 Policy framework

12.1.3.1 State energy plan

Arkansas' state energy plan, the 'Sustainable Energy Resources ("SER") Action Guide,' was published by the APSC in December 2010 following the opening of a Commission Docket two years prior seeking to develop the guide [Docket No. 08-144-U].[528]

The guide is a 24-page document that covers two key elements:[529]

- **Energy efficiency,** including Orders requiring energy efficiency programs in the state; aligning utility and customer incentives to save energy; encouraging the development of energy efficiency projects by commercial and industrial ("C&I") customers; and exploring energy efficiency on the utility side of the meter.

- **Smart grid and emerging technologies,** which includes two areas: the monitoring of projects related to smart grids, advanced metering infrastructure, and demand response; and initiating a Docket to consider the impact of alternative fuel vehicles (both electric and natural gas) and determine whether policy changes are needed to cater to these.

The recommendations were made following extensive stakeholder engagement, which included a dozen public workshops and over 250 filings of testimony, comments, and legal briefs spread across three dockets.[530]

Along with the guide, the APSC issued and passed 10 Orders in December 2010, directing the state's utilities to: (i) implement the energy efficiency measures outlined in the guide, and (ii) file comprehensive energy efficiency plans annually from 2011 to 2013.[531] Specifically, Order 17 in Docket 08-144-U set the sales reduction targets for both electric and gas utilities to 0.25% and 0.2% in 2011 from 2010 baseline energy sales, respectively.[532] These targets have since been updated through numerous orders and dockets. Most recently, in 2018, the APSC set targets for 2020-2022, establishing an energy savings target of 1.2% of 2018 electric utility baseline sales per year from 2020-2022 (and 0.5% of 2018 gas utility baseline sales per year from 2020-2022).[533]

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[528] CLEAResult. *Commercial & Industrial Energy Efficiency in Arkansas.* 2015.

[529] Arkansas Public Service Commission. *APSC Sustainable Energy Resources (SER) Action Guide.* December 2010.

[530] Ibid.

[531] "Energy Efficiency Targets." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/4545>

[532] Ibid.

[533] Arkansas Public Service Commission. *Docket No. 13-002-U, Order No. 43.* July 13, 2018.

12.1.3.2 Integrated Resource Plan

Arkansas' IRP process is outlined in the APSC's 'Resource Planning Guidelines for Electric Utilities', which is a 5-page document published in January 2007 and approved in Docket 06-028-R.[534] The guidelines establish that IRPs should be updated every three years, with a minimum planning horizon of 10 years.[535]

A guideline worth noting includes the APSC's suggestion that utilities should establish a Stakeholder Committee to assist in the preparation of their IRPs. According to the guidelines, the committee *"should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area,"* and should be tasked with reviewing the utility's objectives, assumptions, and estimated needs early in the planning cycle.[536] This review should be summarized and submitted in a report to the Commission alongside the utility's IRP, at which point the utility may need to re-evaluate its plan and address the Stakeholder Committee's comments.[537]

12.1.3.3 Renewable policies

Arkansas does not have a renewable portfolio standard in place currently.[538]

However, Arkansas does have established energy efficiency standards, as discussed in Section 12.1.3.1.

12.2 Colorado

12.2.1 Overview

Colorado shares numerous similarities with Kansas, including a diverse array of electric suppliers such as IOUs and co-ops, as well as a strong renewables sector, with wind accounting for 21% of electric generation in the state as of the end of 2018.[539] However, Colorado is a diverse state as it also has substantial oil, gas and coal reserves. As of the end of 2018, thermal resources (gas and coal) accounted for nearly 70% of installed capacity in the state, comprising 42% gas-fired facilities and 26% coal-fired facilities. In terms of generation, these thermal resources provide over 75% of the total electric generation in the state. A summary of key electricity data for Colorado is shown in Figure 159 below.

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[534] Arkansas Public Service Commission. *Resource Planning Guidelines for Electric Utilities.* April 1, 2007.

[535] Ibid.

[536] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

[537] Ibid.

[538] "Arkansas State Profile." *EIA*. <https://www.eia.gov/state/analysis.php?sid=AR>

[539] "Colorado Analysis". *US Energy Information Administration*. <https://www.eia.gov/state/analysis.php?sid=CO>

Figure 159. Snapshot of Colorado's electricity industry

Key facts (2017 unless specified)	
Installed capacity	16,017 MW
Demand	54.8 TWh
Load growth (2013-2017)	0.60%
Transmission lines	1,182 miles
Population (2018)	5.7 million
GDP growth (nominal, 2014-2018)	5.0%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

Colorado produces slightly less energy than it consumes and receives the remaining electricity from neighboring states including Wyoming, Nebraska, New Mexico, Utah and Kansas.[540] The commercial sector consumes the largest portion of electricity in Colorado, accounting for 40% of the state's total electricity sales.[541]

12.2.2 Institutional and legal framework

12.2.2.1 Utilities

There are currently 53 utilities operating in the state of Colorado, comprising two IOUs, 29 munis, and 22 rural electric co-ops.[542] IOUs comprise just over half of all retail sales in the state, while co-ops account for more than 27%. Similar to Kansas, there is no retail choice in the state of Colorado, such that all distribution utilities have an exclusive franchise.

[540] Ibid.

[541] Ibid.

[542] "Electric Utilities". *Colorado Energy Office.* <https://www.colorado.gov/pacific/energyoffice/electric-utilities>

12.2.2.2 State energy office

The **Colorado Energy Office** ("CEO") was first established in 1977 as the then Office of Energy Conservation. Over the years, the state's General Assembly has expanded the CEO's role and codified it in the state statute, Section 24-38.5-101.[543]

CEO functional areas

- **Policy** is responsible for intervening in CPUC proceedings, as well as representing the CEO at the state's General Assembly;
- **Transportation Fuels & Technology** focuses mainly on encouraging the proliferation of electric vehicles and other emerging zero emission transportation technologies in the state;
- **Building Innovation & Energy Finance** improves access to energy efficiency and other services to reduce energy consumption and lower energy costs in residential, commercial, industrial, and public buildings;
- **Weatherization Assistance Program** serves low-income households by providing them with energy retrofitting services; and
- **Operations** organizes the CEO's internal processes, including accounting and budgeting.

Source: Colorado Energy Office. *Department Performance Plan.* FY 2019-20.

The CEO lies within the Governor's Office and is a non-regulatory department seeking to "*reduce greenhouse gas emissions and consumer energy costs by advancing clean energy, energy efficiency and zero emission vehicles*."[544] The CEO is comprised of 26 staff members, organized into five functional areas (described in the textbox) that are overseen by a 4-member Executive Director team.[545]

12.2.2.3 Regulator

The **Colorado Public Utilities Commission** ("CPUC") was first established in 1885 as the Railway Commission. The Public Utilities Act was later passed in 2013, granting the CPUC the authority to oversee all public utilities in the state, covering the areas of energy and water, telecommunications, transportation, gas pipeline safety, and rail and transit safety.[546, 547] As such, the CPUC has jurisdiction over the two IOUs in the state, namely Black Hills Energy and the

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[543] Colorado Legislature. *State Energy Program, Colorado Energy Office: Office of the Governor.* November 2014.

[544] "About Us." *Colorado Energy Office.* <https://www.colorado.gov/pacific/energyoffice/about-us-25>

[545] Colorado Energy Office. *Department Performance Plan.* FY 2019-20.

[546] Dean Doug. *Presentation to the Transportation Legislation Review Committee.* Colorado General Assembly.

[547] "Public Utilities Commission." *Colorado Department of Regulatory Agencies.* <https://www.colorado.gov/pacific/dora/puc>

Public Service Company of Colorado (operating as Xcel Energy).[548] The CPUC does not regulate the munis and co-ops in the state, as these utilities are operated as non-profits.

The Commission "*serves the public interest by effectively regulating utilities and facilities so that the people of Colorado receive safe, reliable, and reasonably-priced services consistent with the economic, environmental, and social values of [the] state*."[549] The CPUC consists of three Commissioners, who are first appointed by the Governor and then confirmed by the Senate.[550]

The CPUC regulates the two electric IOUs in the state through 4 CCR 723-3 – Rules Regulating Electric Utilities.[551] Public utilities in the state of Colorado must also comply with the requirements laid out in Colorado Revised Statutes, Title 40 – Public Utilities, also known as the "Public Utilities Law."[552]

12.2.3 Policy framework

12.2.3.1 State energy plan

Colorado released its 'Colorado State Energy Report' in 2014 through a collaborative effort by the state's Energy Office, Department of Natural Resources, and Department of Public Health & Environment.[553] The 30-page report was developed following Executive Order D 2011-003, which was issued in January 2011 and mandated the creation of "*a statewide economic development strategy based on local input.*"[554] The report focuses on four key values:[555]

- **Growing jobs and spurring innovation** through developing the state's energy resources and technologies and training the local workforce. Areas of focus include energy efficiency, alternative fuel vehicles (both electric and natural gas), fossil fuel production and advances in unconventional extraction, and renewable energy.

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[548] Ibid.

[549] "Mission". *Colorado Department of Regulatory Agencies.* <https://www.colorado.gov/pacific/dora/pucmission>

[550] "PUC Objectives." *Colorado Department of Regulatory Agencies.* <https://www.colorado.gov/pacific/dora/pucobjectives>

[551] Colorado Department of Regulatory Agencies: Public Utilities Commission. *Rules Regulating Electric Utilities 4 CCR 723-3.*

[552] Colorado Revised Statutes. *Title 40 – Public Utilities.* 2018.

[553] Colorado Department of Natural Resources, Energy Office, and Department of Public Health and Environment. *Colorado State Energy Report.* 2014.

[554] Ibid.

[555] Ibid.

- **Environmental protection,** including improving air quality, protecting water resources, and preserving wildlife and lands.

- **Streamlining government** by improving the regulatory process and enhancing emergency planning. Specifically, the report calls for the *"elimination of redundant, inconsistent, or unnecessary regulation, without sacrificing public safety and environmental quality."*

- **Encouraging collaboration** among stakeholders and local government.

12.2.3.2 Integrated Resource Plan

Colorado's IRP process is governed by the '4 Code of Colorado Regulations 723-3 Electric Rules 3600-3619.[556] According to these state rules, utilities must file IRP updates every four years, but are given the flexibility to determine their own planning horizons so long as it falls within the range of 20 to 40 years.[557]

These rules also establish both the resources that utilities must evaluate in their IRPs, as well as the amount of weight that either the utilities or the CPUC must give to a particular resource.[558] In addition, the rules require utilities to include information about the life expectancies of the generating units in their IRPs, specifically providing *"the estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense."*[559] Finally, for any resources that utilities propose acquiring to meet load and reserve requirements, they are also required to include draft requests for proposals ("RFPs") within their IRP, which the CPUC must approve before the competitive bidding process can begin.[560]

12.2.3.3 Renewable policies

Of all the states reviewed in this Study, Colorado has the most stringent renewable target, requiring: (1) IOUs to generate 30% of their electricity from renewables by 2020 (of which 3% must come from distributed energy resources); and (2) co-ops to generate 20% of their electricity from renewables by 2020.[561] In May 2019, a new law was passed to escalate these targets (SB 236),

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[556] Code of Colorado Regulations. *4 CCR 723-3.*

[557] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

[558] Ibid.

[559] Ibid.

[560] Ibid.

[561] "Renewable Energy Standard." *Colorado Energy Office.* <https://www.colorado.gov/pacific/energyoffice/renewable-energy-standard>

requiring regulated utilities to submit a Clean Energy Plan which seeks to achieve 100% carbon-free resources by 2050.[562]

Energy efficiency standards were first established in Colorado in 2007 through HB 1037, which set energy and demand saving goals for the state and required IOUs to conduct demand response and demand-side management ("DSM") programs to primarily incent customers to purchase energy efficiency equipment.[563] HB 1227, which was signed in May 2017, extended these programs to 2028, and set goals for the DSM programs to achieve at least 5% peak demand reduction and 5% energy savings by 2028 relative to 2018.[564]

12.3 Iowa

12.3.1 Overview

Figure 160. Snapshot of Iowa's electricity industry

Key facts (2017 unless specified)	
Installed capacity	17,671 MW
Demand	48.9 TWh
Load growth (2013-2017)	1.20%
Transmission lines	8,192 miles
Population (2018)	3.16 million
GDP growth (nominal, 2014-2018)	2.6%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

[562] Colorado General Assembly. *SB19-236: Sunset Public Utilities Commission.* 2019.

[563] "Energy Efficiency Resource Standard." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/4489>

[564] Colorado General Assembly. *HB17-1227: Electric Demand-side Management Program Extension.* 2017.

Iowa was chosen as a comparator state for this Study not only because of its proximity to Kansas, but also due to its similarity in terms of topology and economic activity. Iowa also hosts a significant amount of wind generation, accounting for 45% of installed capacity in the state as of the end of 2018. Other major fuel sources include coal (29%) and natural gas (18%). In terms of generation, wind accounts for 37%, while coal accounts for 44%. This enables Iowa to fulfill all its in-state power needs and also generate excess power for transmission to neighboring states. The industrial sector consumes the largest portion of electricity in the state, accounting for approximately 50% of retail electricity sales.[565] A summary of key electricity data for Iowa is shown in Figure 160.

12.3.2 Institutional and legal framework

12.3.2.1 Utilities

As of 2017, there were 181 utilities operating in Iowa, comprised of two IOUs, 136 munis, and 43 rural electric co-ops.[566] Together, the two IOUs in the state, MidAmerican Energy Company and Interstate Power and Light Company (a subsidiary of Alliant Energy), account for 75% of all retail sales in the state.[567] On the other hand, co-ops and munis account for 14% and 11% respectively. There is no retail competition in Iowa, and all distribution utilities in the state have exclusive franchise over their service territory.

12.3.2.2 State energy office

The **Iowa Energy Office** ("IEO"), within the state's Economic Development Authority, is staffed by six Project Managers and one Energy Team Leader.[568] Through federal funding from the State Energy Plan American Recovery & Reinvestment Act grant, the IEO focuses on implementing the goals and action items set out in the Iowa Energy Plan (to be discussed in Section 12.3.3.1 below). Funding is provided to eligible activities, which include but are not limited to: "*energy workforce development, technology-based research, and development, biomass conversion potential, natural gas expansion, grid modernization, alternative fuel vehicles, access to energy expertise in underserved areas and other activities as approved by IEO*."[569]

12.3.2.3 Regulator

The **Iowa Utilities Board** ("IUB") was established in 1878 through Iowa Code Chapter 476.1 and 474.9. The IUB regulates utilities to "*ensure that reasonably priced, reliable, environmentally*

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[565] "Iowa Analysis." *US Energy Information Administration*. <https://www.eia.gov/state/analysis.php?sid=IA>

[566] "Iowa's Electric Profile." *Iowa Utilities Board*. <https://iub.iowa.gov/iowas-electric-profile>

[567] Ibid.

[568] National Association of State Energy Officials. *NASEO's 2019 Midwest Regional State Energy Officials Meeting*. May 2019.

[569] Iowa Energy Office. *Iowa Energy Management Guide*.

responsible, and safe utility services are available to all Iowans."[570] The IUB is served by a three-member board, all of whom are appointed by the Governor and confirmed by the state Senate.[571]

The IUB has jurisdiction over the following areas: electricity, natural gas, telecommunications, water, sewer and wastewater, and pipeline safety.[572] In terms of regulating electricity, the Board is governed by Iowa Code Chapter 476 – Public Utility Regulation. Under this code, the IUB regulates the rates and services of the two IOUs in Iowa, and also regulates the service, but not the rates, of munis and co-ops in the state (note however that co-ops can opt to be rate regulated by the IUB if they so choose).[573]

12.3.3 Policy framework

12.3.3.1 State energy plan

Iowa released its 100-page 'Iowa Energy Plan' in December 2016, which *"outlines clear goals and strategies to keep energy costs low and further facilitate economic development"* in the state.[574] Development of the plan was chaired by then Lieutenant Governor Kim Reynolds, along with the Iowa Partnership for Economic Progress, the Iowa Economic Development Authority, and the Iowa Department of Transportation.[575] Reynolds is currently Governor of Iowa and has made the implementation of the plan one of her administration's priorities.[576]

The plan was developed following extensive participation by interested stakeholders, which was facilitated through six public forums held across the state, as well as working groups comprised of 48 members who were tasked with identifying potential energy-focused strategies.[577] The final plan includes 15 objectives and 45 strategies covering a 10-year horizon and is built upon four key pillars as illustrated in Figure 161.[578,579]

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[570] "About Us." *Iowa Utilities Board.* <https://iub.iowa.gov/about-us/mission-vision-statements>

[571] Iowa Utilities Board. *Annual Report.* FY 2019.

[572] Ibid.

[573] Ibid.

[574] Iowa Economic Development Authority, and Department of Transportation. *Iowa Energy Plan.* December 2016.

[575] Ibid.

[576] National Association of State Energy Officials. *NASEO's State Energy Planning Guidelines.* 2018.

[577] Iowa Economic Development Authority, and Department of Transportation. *Iowa Energy Plan.* December 2016.

[578] Ibid.

[579] "Iowa Energy Plan." *Iowa Economic Development Authority, and Department of Transportation.* <http://www.iowaenergyplan.org/>

Figure 161. Iowa Energy Plan's pillars and objectives

Source: Iowa Economic Development Authority, and Department of Transportation. *Iowa Energy Plan – Executive Summary*. December 2016.

12.3.3.2 Integrated Resource Plan

Currently, utilities in Iowa are not required to submit IRPs to the IUB.[580,581] Instead, they are required by Iowa Code 476.6(16) to submit an annual report, which includes a complete financial report of the utility's receipts and expenditures, as well as a list of applications filed, including the board fees paid for each docket.[582]

12.3.3.3 Renewable policies

Iowa became the first state in the country to adopt a renewable portfolio standard when it passed the Alternative Energy Production law, which requires the two IOUs in the state to procure a combined renewable generating capacity of 105 MW.[583] In addition, the Iowa Mandatory Utility Green Power Option, which was implemented in 2004, requires all electric utilities operating in

[580] Energy Star. *Energy Efficiency and Electric Infrastructure in the State of Iowa.* December 21, 2015.

[581] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

[582] Iowa Code 2019. *Public Utility Regulation, Section 476.16.*

[583] "Alternative Energy Law Iowa." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/265>

the state to offer their customers the option to purchase alternative electricity generated from renewable sources.[584]

As for energy efficiency, SB 2386, which was enacted in 2008, requires the IUB to set electricity savings targets for rate-regulated electric and natural gas utilities in the state.[585] Munis and co-ops, which tend not to be rate regulated, are required to set their own energy efficiency goals. Regardless, all utilities operating in the state are required to submit annual reports to the IUB describing their energy efficiency efforts.

12.4 Missouri

12.4.1 Overview

Missouri was selected as a comparator state in this Study given its proximity to Kansas, as well as the fact that two of the IOUs in Kansas also operate in Missouri (KCP&L and Empire). Missouri also has a large thermal fleet, primarily comprised of coal (50% of installed capacity as of 2018) and natural gas (31%). Coal-fired facilities account for 80% of the total electric generation in the state. A summary of key electricity data for Missouri is shown in Figure 162 below.

Figure 162. Snapshot of Missouri's electricity industry

Key facts (2017 unless specified)	
Installed capacity	21,809 MW
Demand	76.5 TWh
Load growth (2013-2017)	-2.20%
Transmission lines	6,528 miles
Population (2018)	6.13 million
GDP growth (nominal, 2014-2018)	2.9%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

[584] "Mandatory Utility Green Power Option." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/225>

[585] "Energy Efficiency Standard." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/4537>

12.4.2 Institutional and legal framework

12.4.2.1 Utilities

Electric co-ops and munis serve large portions of the state, but populations concentrated in urban cities such as St. Louis and Kansas City are served by IOUs. As such, IOUs account for two-thirds of all retail sales in the state, followed by co-ops who serve 19%. The four regulated electric utilities in Missouri are:[586]

- Ameren Missouri;
- Empire District Electric Company;
- Evergy Missouri Metro (formerly Kansas City Power & Light);
- Evergy Missouri West (formerly KCP&L Greater Missouri Operations Company)

There is no retail competition in the state, and all distribution utilities have an exclusive franchise.

12.4.2.2 State energy office

Missouri's **Division of Energy** ("DOE"), formerly located within the state's Department of Economic Development, was transferred to the Department of Natural Resources in 2019 through Executive Order 19-01.[587] Therein, the Division's responsibilities are described as "*coordinating actions relating to energy sustainability in the State, renewable energy use, and energy conservation*."[588]

DOE programming

- **Energy policy and resources**, which includes providing policy research, renewable energy standard certifications, and building code and energy resources assessments, among others;
- **Energy efficiency,** which conducts energy efficiency efforts and initiatives for the state;
- **Weatherization assistance program**, which provides funds for low-income, elderly, and disabled residents with regards to their weatherization efforts; and
- **Fiscal and administrative,** which focuses on budgeting and accounting.

Source: "What We Do." *Missouri Department of Natural Resources, Division of Energy.* <https://energy.mo.gov/about/staff#programs>

[586] "Regulated Electric Companies". *Missouri Public Service Commission*. <https://psc.mo.gov/Electric/>

[587] State of Missouri. *Executive Order 19-01.* January 17, 2019.

[588] Ibid.

Missouri's state energy office has among the broader scopes as compared to other states reviewed in this Study, as the Division was tasked with the development of Missouri's energy plan. Approximately 35 employees serve the Division, whose programs are discussed in the textbox above.[589]

12.4.2.3 Regulator

The **Missouri Public Service Commission** ("MPSC") was established in 1913.[590] The Commission's mission is to "*ensure that Missourians receive safe and reliable utility services at just, reasonable and affordable rates*."[591] There are five Governor-appointed and Senate consented commissioners serving the MPSC.[592] The Commission has jurisdiction over the following areas:[593]

- investor-owned electric, natural gas, steam, water and sewer utilities;
- telecommunications (although this jurisdiction is limited);
- the manufacturers and dealers of manufactured homes in the state; and
- the operational safety of Missouri's rural electric co-ops and municipally owned natural gas utilities.

Chapter 386 of Missouri's state statutes, also known as the "Public Service Commission Law," dictates the authority of the MPSC.[594] Specifically, Chapters 393 and 394 govern the gas, electric, water, heating, and sewer utilities, as well as rural electric co-ops operating in Missouri.[595] The statutes dictate the responsibilities of utilities to provide safe and adequate service and requirements for rate adjustments among others.

12.4.3 Policy framework

12.4.3.1 State energy plan

Missouri's 302-page energy plan, the 'Missouri Comprehensive State Energy Plan,' was published by the Division of Energy within the Department of Economic Development in October

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589 "Missouri DNR Welcomes Division of Energy." *Douglas County Herald.* <https://douglascountyherald.com/2019/09/missouri-dnr-welcomes-division-of-energy/>

590 "About the PSC". *Missouri Public Service Commission*. <https://psc.mo.gov/General/About_The_PSC>

591 Ibid.

592 Ibid.

593 "About the PSC". *Missouri Public Service Commission*. <https://psc.mo.gov/General/About_The_PSC>

594 "Title XXV Incorporation and Regulation of Certain Utilities and Carriers". *State of Missouri Revisor of Statutes.* <https://revisor.mo.gov/main/OneSection.aspx?section=386.010&bid=21687&hl=>

595 "Title XXV Incorporation and Regulation of Certain Utilities and Carriers". *State of Missouri Revisor of Statutes.* <https://revisor.mo.gov/main/OneChapter.aspx?chapter=393>

2015.[596] The plan was developed following the issuance of Executive Order 14-06 in 2014, which charged the Division with developing the state's first comprehensive energy plan.

The Division of Energy was originally housed within the Department of Natural Resources, but was transferred to the Department of Economic Development in 2013 through Executive Order 13-02.[597] This reorganization stemmed from the recognition that *"residents and businesses depend on affordable and reliable energy, and that opportunities exist to attract high-paying energy jobs to [the] state that advance economic development."*[598] As mentioned in Section 12.4.2.2, the Division was recently transferred back to the Department of Natural Resources in 2019.

Through seven public meetings,[599] several working groups (on which 514 individuals served on one or more), and 194 comments posted through the Division's website,[600] the plan established recommendations centered around five key pillars:[601]

- promoting **energy efficiency**;
- ensuring **affordability** and **reliability,** especially among vulnerable populations;
- **diversifying** and promoting **security** in supply by *"maximizing in-state clean energy resources and decreasing dependence on imported fossil fuel energy sources;"*
- undertaking **regulatory improvements;** and
- stimulating **innovation, emerging technologies,** and **job creation.**

12.4.3.2 Integrated Resource Plan

Missouri's IRP process is established through '4 CSR 240-22 Electric Utility Resource Planning', which states that IRP updates must be submitted every three years, considering a planning horizon of 20 years.[602] According to these rules, each utility is required to consider demand-side resources, renewable energy, and supply-side resources on an equal footing.[603]

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[596] Missouri Department of Economic Development. *Missouri Comprehensive State Energy Plan.* October 2015.

[597] National Association of State Energy Officials. *NASEO's State Energy Planning Guidelines.* 2018.

[598] Ibid.

[599] "Comprehensive State Energy Plan." *Missouri Department of National Resources.* <https://energy.mo.gov/comprehensive-state-energy-plan>

[600] National Association of State Energy Officials. *NASEO's State Energy Planning Guidelines.* 2018.

[601] Missouri Department of Economic Development. *Missouri Comprehensive State Energy Plan – Executive Summary.* October 2015.

[602] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

[603] Code of Missouri Regulations. *4 CSR 240-22.*

12.4.3.3 Renewable policies

The Missouri Clean Energy Act, passed in 2008, established the state's mandatory renewable portfolio standard and replaced the voluntary renewable energy and energy efficiency objective that was in place at the time.[604] The Act requires IOUs in the state to use renewables to meet 15% of their annual retail sales by 2021 and each year thereafter – note that the RPS does not apply to munis or co-ops operating in the state.[605]

To meet this goal, IOUs can choose from a range of eligible renewable energy technology options including, but not limited to, solar PV, solar thermal, wind, small hydropower (defined as having a capacity of 10 MW or less), and biogas.[606] In addition, IOUs are also required to submit annual compliance reports and plans to the MPSC (under 20 CSR 4240-20.100).[607] The report must detail how the utility is planning to meet the standard for the current year and the two years thereafter.[608]

In terms of energy efficiency efforts in the state, Missouri enacted the Missouri Energy Efficiency Investment Act in 2009, calling on IOUs to design energy efficiency programs and providing a cost-recovery structure that allows utilities to earn a profit on the electricity saved as a result of these programs.[609] Participation under the Act is voluntary, with a non-binding guideline of achieving demand-side savings of 1.9% of electricity sales by 2020.[610]

12.5 North Dakota

12.5.1 Overview

North Dakota was chosen as a comparator state for two reasons: (1) the state has a significant oil and gas extraction industry, as the second largest oil-producing state in the country; and (2) its electricity industry is comprised of a diverse range of suppliers, including IOUs and co-ops. A summary of key electricity data for North Dakota is shown in Figure 163 below.

In terms of installed capacity, North Dakota's fuel mix is similar to Kansas's in that it is dominated by coal (48%) and wind (37%). As for generation, coal accounts for 64%, while wind accounted

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[604] "Missouri Renewable Energy Standard". *DSIRE.* <https://programs.dsireusa.org/system/program/detail/2622 >

[605] Ibid.

[606] Ibid.

[607] "Renewable Energy Standard Compliance Reports/Plans." *Missouri Public Service Commission.* <https://psc.mo.gov/electric/Renewable_Energy_Standard_Compliance_Reports>

[608] "Missouri Renewable Energy Standard". *DSIRE.* <https://programs.dsireusa.org/system/program/detail/2622 >

[609] "Missouri Energy Efficiency Investment Act (MEEIA)." *Missouri Saves.* <https://mosaves.com/missouris-energy-efficiency-laws-policies/missouri-energy-efficiency-investment-act-meeia/>

[610] "Energy Efficiency Goals." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/5214>

for 27%.[611] North Dakota generates more electricity than the state consumes, and thus transmits excess generation primarily to Minnesota, Montana, and South Dakota.[612] In North Dakota, industrial consumers account for the largest share of retail electric sales.

Figure 163. Snapshot of North Dakota's electricity industry

Key facts (2017 unless specified)	
Installed capacity	8,234 MW
Demand	20.1 TWh
Load growth (2013-2017)	5.90%
Transmission lines	7,256 miles
Population (2018)	0.76 million
GDP growth (nominal, 2014-2018)	-0.9%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

12.5.2 Institutional and legal framework

12.5.2.1 Utilities

In the state of North Dakota, there are three IOUs, approximately 19 electric co-ops, and two municipally or publicly owned utilities.[613] Co-ops comprise more than two-thirds of all retail sales in the state. The three IOUs operating in North Dakota are:[614]

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611 "North Dakota". *US Energy Information Administration*. <https://www.eia.gov/state/analysis.php?sid=ND>

612 Ibid.

613 Energy Star. *Energy Efficiency and Electric Infrastructure in the State of North Dakota.* December 21, 2015.

614 "Jurisdiction: Electric and Gas." *North Dakota Public Service Commission*. <https://www.psc.nd.gov/jurisdiction/electricgas/index.php>

- Montana-Dakota Utilities Co.;
- Northern States Power Company (Xcel Energy); and
- Otter Tail Corporation.

There is no retail competition in North Dakota, as all distribution utilities have exclusive franchise over their service territory.

12.5.2.2 State energy office

The **North Dakota Division of Community Services**, which lies within the state's Department of Commerce, has a relatively narrow scope as it "*was established to provide technical assistance to local governments and state agencies in the areas of community and rural planning and development, policy research and development, and grant program implementation.*"[615] In terms of its energy-related initiatives, the 7-person Division conducts the following programs:[616]

- **State Energy Program,** which allocates federal funding to applicants conducting energy efficiency and conservation-related activities including energy education, installation of energy-efficient measures, transportation initiatives (such as alternative fuel vehicles), and renewable energy technologies (including small-scale wind turbines and solar technologies).[617]
- **The Energy Conservation Grant,** which assists local government in making energy efficiency improvements to public buildings.[618]

12.5.2.3 Regulator

The **North Dakota Public Service Commission** ("NDPSC") was established in 1940 through the renaming of the 1885 Railroad Commission.[619] The Commission's oversight duties currently cover the following areas: electricity, natural gas, telecommunications, railroad, and pipeline safety. The Commission is comprised of three elected Commissioners who serve staggered six-year terms.[620]

In terms of electricity, the NDPSC oversees the retail electric services provided by the three IOUs operating in the state, including rate regulation, establishing safety requirements, resolving

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615 "Community Services." *North Dakota Department of Commerce.* <https://www.communityservices.nd.gov/>

616 "Staff." *North Dakota Department of Commerce.* <https://www.communityservices.nd.gov/about/Staff/>

617 "State Energy Program." *North Dakota Department of Commerce.* <https://www.communityservices.nd.gov/renewableenergyprograms/StateEnergyProgram/>

618 "Energy Conservation Grant." *North Dakota Department of Commerce.* <https://www.communityservices.nd.gov/renewableenergyprograms/EnergyConservationGrant/>

619 North Dakota Public Service Commission. *Biennial Report.* 2017-2019.

620 Ibid.

territorial disputes, and siting energy conversion and transmission facilities.[621] The laws governing the Commission's regulation of public electric utilities in North Dakota are stated in Chapters 28 and 49 of the North Dakota Century Code.[622]

12.5.3 Policy framework

12.5.3.1 State energy plan

North Dakota is one of the only states in the US with a multi-resource energy policy, which is outlined in its 36-page 'Empower North Dakota' report.[623] The comprehensive energy policy was first published in 2008 with an outlook up until 2025, which included 21 goals, 40 policy statements, and 98 action items.[624]

The policy was legislatively mandated through the 2007 Session Laws Chapter 204 § 6, which tasked the Department of Commerce with convening a commission dedicated to developing a comprehensive energy policy to be submitted to the Legislative Council.[625] The resulting EmPower ND Commission is currently comprised of 16 members.[626]

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621 "Jurisdiction: Electric & Gas." *North Dakota Public Service Commission.* <https://www.psc.nd.gov/jurisdiction/electricgas/index.php>

622 North Dakota Legislative Branch. *Century Code. Chapter 49-04 Duties of Public Utilities.* 2017.

623 "Public Awareness: Laws, Rules and Other." *North Dakota Public Service Commission.* <https://psc.nd.gov/public/laws/lawselectricgas.php>

624 Ibid.

625 Ibid.

626 "EmPower North Dakota." *North Dakota Department of Commerce.* <https://www.business.nd.gov/energy/EmPowerNorthDakota/>

The published policy *"offers a balanced approach to encourage growth in all energy sectors, emphasizing energy efficiency, environmentally friendly policies, and practices and strongly supporting research and development of cleaner technologies"* and includes the goals outlined in the textbox, among others.[627]

In July 2016, the Commission released its fifth review of the energy policy through a 16-page update and recommendation report.[628] Their recommendations centered around infrastructure, R&D in energy and agriculture (including integrating renewables with traditional energy resources, meeting federal climate policy objectives, and exploring greenhouse gas ("GHG") emission reductions), as well as the regulatory environment in the state.[629]

Empower North Dakota's goals

- Increased **energy production** from all sources.
- Increased **wind capacity**, as well as **export capacity**.
- Building **clean-coal electric generation plants** and new **biodiesel plants**.
- **Retrofitting** existing facilities.
- Developing **biomass** production and use in the state.
- Pursuing **energy efficiency**.

Source: Empower North Dakota. *Comprehensive State Energy Policy 2008-2025.* 2008.

12.5.3.2 Integrated Resource Plan

As mentioned previously, the NDPSC is responsible for regulating three IOUs in the state: Montana-Dakotas Utilities Company ("MDU"), Otter Tail Power Company, and the Northern States Power Company.[630] However, as the Otter Tail Power Company and the Northern States Power Company both serve portions of Minnesota, the Minnesota Commission governs their IRP requirements. Therefore, these two IOUs submit their IRPs to the Minnesota Commission biennially and provide copies of their IRPs to the NDPSC for informational purposes only.[631]

The only utility formally required to submit IRPs to the NDPSC is MDU. In 1987, MDU was required to file its IRP on an annual basis, but following an amended order in March 1992 [Case

[627] Empower North Dakota. *Comprehensive State Energy Policy 2008-2025.* 2008.

[628] Empower North Dakota. *2016 Policy Updates and Recommendations.* 2016.

[629] Ibid.

[630] Regulatory Assistance Project. *Electric Resource Long-range Planning Survey – North Dakota.* September 17, 2005.

[631] Ibid.

No. PU-399-91-689], this requirement was altered to allow for biennial filings.[632] Therein, MDU is also ordered to consider a planning horizon of 20 years.[633]

12.5.3.3 Renewable policies

North Dakota's renewable portfolio goal was enacted in March 2007 under HB 1506, which established a voluntary objective of generating 10% of all retail electricity from renewables by 2015.[634] This voluntary goal applied to all electric utilities operating in the state, including IOUs, munis, and co-ops. As part of the legislation, retail providers were required to report their progress to the NDPSC annually, including information such as the percentage of energy sales from renewables and a qualitative analysis of the steps taken to meet the goal.[635] In 2017, this reporting requirement was extended beyond 2016 under SB 2313.[636]

On the other hand, North Dakota has not enacted any regulatory policies with regards to energy efficiency. Rather, utilities offer energy efficiency programs on their own accord. For example, Otter Tail Power offers a financing program for energy efficiency improvements, Northern Plains Electric Cooperative provides loans to commercial customers for similar energy efficiency improvements, and Xcel Energy, as well as several munis, offer rebates for energy-efficient appliances.[637]

12.6 Oklahoma

12.6.1 Overview

Oklahoma, similar to Kansas, has significant thermal and wind generation. In terms of installed capacity, natural gas (56%) comprises the largest share of the fuel mix, followed by wind (27%) and coal (12%). Also mirroring Kansas, Oklahoma is the only other state in this Study which falls entirely within SPP's footprint. A summary of key data for the state of Arkansas is shown in Figure 164 below.

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[632] Ibid.

[633] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning*. June 2013.

[634] "Renewable and Recycled Energy Objective." *DSIRE*. <https://programs.dsireusa.org/system/program/detail/2697>

[635] Ibid.

[636] Ibid.

[637] "Customer Energy Efficiency Programs." *American Council for an Energy-Efficient Economy*. <https://database.aceee.org/state/customer-energy-efficiency-programs>

Figure 164. Snapshot of Oklahoma's electricity industry

Key facts (2017 unless specified)	
Installed capacity	26,691 MW
Demand	60.5 TWh
Load growth (2013-2017)	0.20%
Transmission lines	3,953 miles
Population (2018)	3.94 million
GDP growth (nominal, 2014-2018)	1.1%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: EIA data; commercial third-party database; Bureau of Economic Analysis.

12.6.2 Institutional and legal framework

12.6.2.1 Utilities

There are three IOUs, five regulated electric co-ops, 25 unregulated electric co-ops, and 11 munis operating in the state of Oklahoma.[638] Two of the IOUs in the state account for nearly 70% of all electric sales, followed by co-ops and munis who comprise 20% and 10% of the state's electricity sales respectively. In addition, there is currently no retail competition in Oklahoma, and all distribution utilities have an exclusive franchise.

12.6.2.2 State energy office

The **Oklahoma State Energy Office** lies under the state's Secretary of Energy & Environment.[639] However, the Office receives federal funding to operate it's State Energy Program, which seems

[638] "Oklahoma Electricity." *Kansas Energy Information Network.* <http://www.kansasenergy.org/OK_electricity.htm>

[639] "Oklahoma State Energy Office." *Oklahoma Secretary of Energy & Environment.* <http://ee.ok.gov/what-we-do/state-energy-office/>

to be planned under the state's Secretary of Commerce & Tourism.[640] The funding is used to finance efforts in "*energy efficiency, renewable energy, and alternative fuels through communication, outreach, technology deployment and access to partnerships and resources.*"[641]

The **Oklahoma Office of Secretary of Energy & Environment** ("OSEE") was established in 1986 through the Executive Branch Reform Act.[642] The Office serves as the Governor's chief advisor on energy and environmental issues, and also oversees the state's energy and environmental agencies.[643]

OSEE programming

- **Tax Credits**. Provides income tax credits to energy efficient residential constructions, zero emissions facilities, and alternative fuel vehicles and infrastructures.
- **Energy Efficiency**. Partners with the Oklahoma Uniform Building Code Commission in providing energy efficiency programs to residential and commercial customers. These programs are managed by the state's utilities.
- **Renewable Energy**. Works with the Department of Energy to help facilitate the deployment of renewables in the state, with a focus on wind, solar, and geothermal technologies.
- **Alternative Fuel Vehicles**. Promotes the use of alternative fuel vehicles and infrastructures through financial incentives.

Source: "Oklahoma Secretary of Energy & Environment." *Oklahoma Secretary of Energy & Environment.* <http://ee.ok.gov/resources/>

The Office is led by six members with the titles of Secretary, Deputy, Director to Council, Advisor, and Manager.[644] The OSEE's electricity-related programs are highlighted in the textbox above.

12.6.2.3 Regulator

The **Oklahoma Corporation Commission** ("OCC") was established in 1907 through Article 9 of the Oklahoma Constitution and was given the authority to regulate public service corporations

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[640] National Association of State Energy Officials. *NASEO's 2018 Central Regional State Energy Officials Meeting.* May 2018.

[641] "Oklahoma State Energy Office." *Oklahoma Secretary of Energy & Environment.* <http://ee.ok.gov/what-we-do/state-energy-office/>

[642] "Okla. Admin. Code § 1:2011-6B". *Case Text.* <https://casetext.com/regulation/oklahoma-administrative-code/title-1-executive-orders/section-12011-6b>

[643] "What We Do." *Oklahoma Secretary of Energy & Environment.* <http://ee.ok.gov/what-we-do/>

[644] "Contact Us". *Oklahoma Secretary of Energy & Environment.* <http://ee.ok.gov/contact-us/>

by the First Legislature.[645] The Commission is charged with "*balancing the rights and interests of Oklahoma citizens through the development and enforcement of regulations in an open, transparent, ethical, and just manner.*"[646] The Commission is comprised of three commissioners elected by statewide vote to serve six-year terms. Terms are staggered such that one position becomes vacant every two years.

The OCC has one of the broadest mandates of all the regulators reviewed in this Study. The Commission's jurisdiction covers electricity, natural gas, water, oil and gas extraction, intrastate pipeline safety, telecommunications, transportation, and railroads.[647]

In terms of electric utilities, the OCC regulates the prices and service reliability of the following IOUs and co-ops:[648]

- Empire District Electric;
- Oklahoma Gas and Electric ("OG&E");
- Public Service Company of Oklahoma;
- Arkansas Valley Electric Cooperative;
- Canadian Valley Electric Cooperative;
- Northeast Oklahoma Electric Cooperative;
- Rich Mountain Electric Cooperative, Inc.; and
- Southwest Arkansas Electric Cooperative.

The OCC also regulates the service reliability of the other co-ops operating in the state, who have opted out of price regulation.[649]

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[645] Oklahoma Corporation Commission. *Oklahoma Corporation Commission Strategic Plan*. January 2018.

[646] "Our Mission." *Oklahoma Corporation Commission.* <http://www.occeweb.com/Comm/Mission_Vision_2018.htm>

[647] "Industry." *Oklahoma Corporation Commission.* <http://www.occeweb.com/includes/Industry.html>

[648] "Electric Utilities." *Oklahoma Corporation Commission.* <http://www.occeweb.com/PU/GasAndElectricUtilities/puregelectric.htm>

[649] Ibid.

12.6.3 Policy framework

12.6.3.1 State energy plan

The 'Oklahoma First Energy Plan' was published in 2011 by the Office of the then Governor, Mary Fallin (who served from 2011 to 2019).[650] The 41-page report outlines the following objectives:[651]

- Enhance **natural gas, oil,** and **coal** production.
- Encourage renewable energy, specifically the build-out of the local **wind industry**.
- Ensure energy **affordability** and **efficiency**.
- Invest in **R&D** through the Oklahoma Energy Initiative.
- Enhance energy production to **create jobs** and **grow the economy**.
- Reduce the state's dependence on **foreign oil**.

According to the National Association of State Energy Officials, this plan is currently operational, with additional planning efforts being conducted through the state's energy office.[652]

12.6.3.2 Integrated Resource Plan

Oklahoma's IRP process is governed by OAC 165:35-37-4,[653] which requires utilities to submit IRP updates to the Oklahoma Corporation Commission every three years, with a planning horizon of 10 years.[654] These rules also dictate the requirement for the Commission to conduct a public meeting to allow *"comment from interested persons as to the strengths and weaknesses of the proposed plan,"* which the utility is then expected to take into account and make adjustments to their IRP, within reason.[655]

12.6.3.3 Renewable policies

North Dakota's renewable energy goal was established in May 2010 when the state's Legislature enacted the Oklahoma Energy Security Act (HB 3028), which called for 15% of total installed

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[650] Oklahoma Office of the Governor. *Oklahoma First Energy Plan.* 2011.

[651] Ibid.

[652] "State Energy Plans – Oklahoma." *National Association of State Energy Officials.* <https://www.naseo.org/stateenergyplans-state?State=OK>

[653] Oklahoma Corporation Commission. *OAC 165:35-37-4.*

[654] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

[655] Oklahoma Corporation Commission. *OAC 165:35-37-4.*

capacity to be from renewables by 2015.[656] This goal applied to all electric utilities in the state, including IOUs, co-ops, and munis.

Since the implementation of the Act, there have been no efforts to extend the goal beyond 2015.[657] In 2015, the OCC reported that the state had reached 25.9% of the total installed capacity derived from eligible renewables and demand-side management.[658]

On the other hand, Oklahoma has not enacted any regulatory policies with regards to energy efficiency. However, under OAC 165:35-41-4, all electric utilities under rate regulation by the OCC are required to propose energy efficiency and demand-response programs at least once every three years.[659] Although the number of energy efficiency programs offered in the state has increased in recent years, the levels of investment and performance remain below the national average.

12.7 South Dakota

12.7.1 Overview

LEI has considered South Dakota for comparison because its energy mix is comprised of significant thermal and renewable resources. In 2018, 40-60% of electric generation came from hydroelectric power at South Dakota.[660] Wind power accounted for an additional 25% of net generation in 2018, which increased from just 2% in 2008.[661] The remaining 20% of generation comes mostly from coal-fired plants, reduced from a 50% share eleven years ago. In contrast, natural gas has grown to 10% of the generation mix.[662] A summary of key data for South Dakota is shown in Figure 165 below.

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[656] "Renewable Energy Goal." *DSIRE.* <https://programs.dsireusa.org/system/program/detail/4178>

[657] Ibid.

[658] Ibid.

[659] Ibid.

[660] "South Dakota Profile Analysis". *US Energy Information Administration*. March 21, 2019. <https://www.eia.gov/state/analysis.php?sid=SD>

[661] Ibid.

[662] Ibid.

Figure 165. Snapshot of South Dakota electricity industry

Key facts (2017 unless specified)	
Installed capacity	4,129 MW
Demand	12.3 TWh
Load growth (2013-2017)	0.20%
Transmission lines	5,245 miles
Population (2018)	0.88 million
GDP growth (nominal, 2014-2018)	3.1%

Installed capacity by fuel type (2018)

Installed capacity by ownership (2018)

Source: Regulator and utility annual reports; Energy Information Administration, *State Electricity Profiles*. January 2019.

12.7.2 Institutional and legal framework

12.7.2.1 Utilities

Within the state of South Dakota, there are six IOUs (regulated by the state Commission), 29 electric co-ops, 3 generation and transmission co-ops, and 37 municipal electric utilities.[663]

12.7.2.2 State energy office

South Dakota does not have a clearly mandated state energy office similar to those in other states under review. Instead, South Dakota has the Energy Management Office, within the state's Bureau of Administration, which is responsible for coordinating "*the state's purchases and efficient use of energy, including contact with the Western Area Power Administration (Western) and energy management programs.*"[664] As part of its responsibilities, the Office advises state facilities on the implementation of energy saving efforts and "*assists them in developing energy management strategies like load shaping and long-term efficiency plans.*"[665] In addition, the Statewide Energy

[663] "South Dakota Utility Providers". *South Dakota Public Utilities Commission*. October 29, 2019." <https://puc.sd.gov/consumer/sdutilityproviders.aspx>

[664] South Dakota Bureau of Administration. "Statewide Energy Management." <https://boa.sd.gov/state-engineer/energy-management.aspx>

[665] Ibid.

Manager "*advises the state on electric deregulation and negotiates energy supply and delivery contracts.*"[666]

12.7.2.3 Regulator

The **South Dakota Public Utilities Commission** ("SDPUC") is given legislative and statutory authority under Title 49 of the South Dakota Code, and is responsible for developing just and reasonable rates charged by IOUs for natural gas, electric, and telephone service for customers.[667] South Dakotans elect their three Commissioners in a staggered manner (one Commissioner is elected every two years), with each Commissioner serving a six-year term.[668]

The SDPUC is responsible for oversight of the six IOUs which cover various service territories in the state, including Black Hills Energy, MidAmerican Energy, Montana-Dakota Utilities Co., NorthWestern Energy, Otter Tail Power Co. and Xcel Energy.

12.7.3 Policy framework

12.7.3.1 State energy plan

South Dakota does not currently have a state energy plan in place.[669]

12.7.3.2 Integrated Resource Plan

Under SDCL 49-41B-3, the six IOUs are required to submit IRPs to the SDPUC every two years, considering a planning horizon of 10 years.[670] This plan should summarize the utility's current generation portfolio, as well as its plans for future plants and transmission lines. Also, retirement schedules are included, with utilities required to "*include those facilities to be removed from service during the planning period, along with the projected date of removal from service and the reason for removal.*"[671]

12.7.3.3 Renewable policies

Similar to Kansas, the renewable goal in South Dakota is voluntary. In February 2008, H.B. 1123 established a voluntary objective – South Dakota's Renewable, Recycled and Conserved Energy

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[666] Ibid.

[667] "History of the South Dakota Public Utilities Commission". *South Dakota Public Utilities Commission*. 2001. <https://puc.sd.gov/commission/Publication/PUC%20history.pdf>

[668] South Dakota Public Utilities Commission. *About the PUC*. October 16, 2019. <https://puc.sd.gov/whatispuc/default.aspx>

[669] National Association of State Energy Officials. "State Energy Plans – South Dakota." <https://www.naseo.org/stateenergyplans-state?State=SD>

[670] South Dakota Public Utilities Commission. "Electric Utility 10-Year Plans." <https://puc.sd.gov/10utilityyearplan/default.aspx>

[671] Ibid.

Objective, aiming to source 10% of all retail electricity sales from renewable and recycled energy sources by 2015.[672][673] The legislation also required utilities to file their annual electricity sales to the Commission. In March 2009, this policy was modified to allow "conserved energy" to meet the objective. [674]

12.8 Texas

12.8.1 Overview

Texas was selected for review by LEI, given its resource similarities to Kansas, namely its large thermal fleet and significant wind installed capacity. It is the largest geographical state considered in the comparables, and the state's main source of power comes from natural gas, accounting for roughly 50% of generation.[675] The share of coal-fired generation has been steadily decreasing to about 25% of the supply.[676] Wind power, in contrast, has rapidly increased to 17%.[677] Over the past decade, new plant additions in Texas have been driven primarily by natural gas, wind and solar. The remaining power supply mainly comes from nuclear power, accounting for about 10% of the total generation.[678] A summary of the key electricity data is shown in Figure 166 below.

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[672] Database of State Incentives for Renewables & Efficiency. Program. *South Dakota Renewable, Recycled and Conserved Energy Objective*. June 27, 2018. <https://programs.dsireusa.org/system/program/detail/2898>

[673] South Dakota Public Utilities Commission. Commission Action. *Renewable, Recycled and Conserved Energy Objective Annual Reports*. October 16, 2019. <https://puc.sd.gov/energy/reo/reo.aspx>

[674] Ibid.

[675] "Texas Profile Analysis". *US Energy Information Administration*. February 21, 2019. <https://www.eia.gov/state/analysis.php?sid=TX>

[676] Ibid.

[677] Ibid.

[678] Ibid.

Figure 166. Snapshot of Texas electricity industry

Key facts (2017 unless specified)	
Installed capacity	123,512 MW
Demand	410.9 TWh
Load growth (2013-2017)	1.50%
Transmission lines	25,854 miles
Population (2018)	28.7 million
GDP growth (nominal, 2014-2018)	3.5%

Source: Regulator and utility annual reports; Energy Information Administration, *State Electricity Profiles*. January 2019.

12.8.2 Institutional and legal framework

In this section, we consider the institutions and legal framework that utilities in Texas operate under. In general, public utilities in Texas must comply with the Public Utility Regulatory Act ("PURA"). The statute includes requirements for rates, service regulations, and utility competition.[679]

12.8.2.1 Utilities

There are 381 power generation companies ("PGCs") currently registered with and regulated by the **Public Utility Commission of Texas** ("PUCT").[680] As defined by the PUCT, a PGC is *"a person that generates electricity intended to be sold at wholesale and does not own a transmission or distribution facility in [the] state."*[681] Vistra, NRG Energy, and Calpine operate 37% of generating capacity and provide 46% of the energy consumed in ERCOT.[682]

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679 "Texas Statutes". *Texas Constitution and Statutes*. <https://statutes.capitol.texas.gov/?link=UT>

680 Public Utility Commission of Texas. *Power Generation Companies – Search.* Website. <https://www.puc.texas.gov/industry/electric/directories/pgc/search_pgc.aspx>

681 "Certification and Licensing." PUCT. <https://www.puc.texas.gov/industry/electric/business/pgc/pgc.aspx>

682 Third party commercial database.

There are 34 transmission and distribution service providers ("TDSPs") in Texas, responsible for owning, maintaining, and operating transmission assets in the State, including IOUs, municipal-owned electric utilities, and co-ops. TDSPs are regulated by the PUCT and are required to provide non-discriminatory access to the grid.[683]

The retail electric market in Texas opened in 2002, brought about by the passage of Senate Bill 7 by the Texas Legislature, which began the project of restructuring the Texas electricity market.[684] There are currently 116 retail electric providers ("REPs") registered with the PUCT.[685] As defined by the PUCT, a REP *"sells electric energy to retail customers in the areas of Texas where the sale of electricity is open to retail competition. A REP buys wholesale electricity, delivery service, and related services, prices electricity for customers, and seeks customers to buy electricity at retail."*[686]

The **Electric Reliability Council of Texas** ("ERCOT") is the ISO that operates the transmission grid and administers the wholesale electricity market in most of Texas. The ERCOT controlled area covers 75% of the state's total area and provides energy to 85% of the state's total load. ERCOT operates a nodal real-time balancing market, as well as day-ahead energy and ancillary services co-optimized market, supplemented with hourly reliability unit commitment. Unlike other ISOs, which are subject to FERC oversight, ERCOT operates under the regulation of the PUCT. This is primarily because ERCOT has few connections with the two major US interstate grid systems, the Eastern and the Western Interconnections.

12.8.2.2 State energy office

The **Texas State Energy Conservation Office** ("SECO") operates within the Texas Comptroller of Public Accounts.[687] The Office is responsible for delivery of energy efficiency and renewable energy programs with the aim of "*significantly reduce energy cost and consumption in the institutional, industrial, transportation and residential sectors.*"[688] The Office is staffed by eight FTEs, with titles ranging from Director, Program Manager, to Engineer.

12.8.2.3 Regulator

As noted above, the electricity sector in Texas is regulated by the PUCT. The PUCT is the state agency and implementing body for policy frameworks that are stipulated in laws and is governed by the Commissioners who are appointed by the Governor. Its daily operation is governed by the Texas Administrative Code ("TAC"), which is a compilation of all state agency rules in Texas. In

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683 "Transmission/Distribution Service Providers." *ERCOT.* <http://www.ercot.com/services/rq/tdsp>

684 PUCT. 2017 Scope of Competition in Electric Markets in Texas. January 2017.

685 PUCT. *Retail Electric Providers*. <https://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx>

686 "Certification and Licensing." PUCT. <https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx>

687 "Comptroller of Public Accounts". *Texas State Historical Association*. <https://tshaonline.org/handbook/online/articles/mbc04>

688 Texas Comptroller of Public Accounts. "SECO." <https://comptroller.texas.gov/programs/seco/about/>

1977, the TAC was created by the Texas Legislature under the Administrative Code Act,[689] whereby the Legislature directed the Office of the Secretary of State to compile, index, and cause to be published the Texas Administrative Code. The PUCT rules are under Texas Administrative Code, Title 16, Part II.

12.8.3 Policy framework

The Legislature is the primary body in charge of setting energy policy within the State of Texas. The Legislature is a bicameral system with a House and Senate, which together are responsible for the setting of laws that govern the energy sector within the State. All legal frameworks must be signed by the Governor, who is the chief executive of the Legislature. In this section, we will consider the state energy plan, the presence of an IRP, and its renewable policies.

12.8.3.1 State energy plan

The 'Texas State Energy Plan' was released by the Governor's Competitiveness Council in July 2008.[690] Then Governor, Rick Perry, established the Council in November 2007, appointing 29 public and private sector leaders and tasking them with identifying issues affecting Texas' competitiveness in the global marketplace.[691]

The 76-page plan included 37 recommendations focused on ensuring a reliable, balanced, and competitively priced energy supply, as well as enhancing energy efficiency and demand response programs in the state, and removing *"barriers in the competitive market that prevent sound economic decisions."*[692] According to the National Association of State Energy Officials, this plan is currently operational.[693]

12.8.3.2 Integrated Resource Plan

Texas does not have a legislatively mandated IRP process at this time. The IRP process first adopted by the state legislature in 1995 was later rescinded after Texas established a wholesale market.[694,695] However, the state has established a filing requirement for long-term procurement planning.[696] This 'Long-Term System Assessment' is mandated according to Section 39.904(k) of

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[689] Texas Legislature. Government Code, §§2002.051-2002.056.

[690] Texas Governor's Competitiveness Council. *2008 Texas State Energy Plan.* July 2008.

[691] Ibid.

[692] Ibid.

[693] National Association of State Energy Officials. "State Energy Plans – Texas." <https://www.naseo.org/stateenergyplans-state?State=TX>

[694] Public Utility Commission of Texas. *Substantive Rules – Chapter 25. Electric.* October 8, 1999.

[695] Lawrence Berkeley National Laboratory. *The Future of Electricity Resource Planning.* September 2016.

[696] Regulatory Assistance Project. *Best Practices in Electric Utility Integrated Resource Planning.* June 2013.

the PURA, which requires the PUCT and the ERCOT to study the *"need for increased transmission and generation capacity"* and report on these needs to the state legislature every even-numbered year.[697]

12.8.3.3 Renewable policies

The Goal for Renewable Energy [P.U.C. Substantive Rule 25.173] was adopted by the Commission in 1999, setting the state's renewable portfolio standard based on a bill enacted by the Legislature as part of restructuring efforts in Texas [S.B. 7]. Texas's RPS mandates 5,000 MW of new renewables to be installed in Texas by 2015, along with an aim to install 10,000 MW of renewable energy capacity by 2025.[698] This goal is a voluntary RPS target, similar to that in Kansas. Also like Kansas, the goal has long been surpassed - by 2006, Texas moved ahead of California as the top wind-producing state with just under 2,900 MW of installed capacity and has retained its position ever since.[699] As of the beginning of 2019, Texas had 24.2 GW of wind capacity installed, the largest of any state, and nearly thrice the capacity of the closest state, Iowa.[700]

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[697] ERCOT. *2018 Long-term System Assessment.* December 2018.

[698] Database of State Incentives for Renewables & Efficiency. Program. *Texas Renewable Generation Requirement.* June 26, 2018. <https://programs.dsireusa.org/system/program/detail/182>

[699] ERCOT. 2017 State of the Grid. April 2018.

[700] EIA website. *Texas ranks first in US-installed wind capacity and number of turbines.* July 31, 2019.

13 Appendix D: SPP modeling assumptions

LEI's modeling topology for SPP includes a total of four zones in SPP, recognizing the major transmission interfaces: Nebraska-Integrated System ("Nebraska-IS"), Kansas-Missouri ("KSMO"), Central,[701] and SPS.[702] The transmission interface limits within the four zones, and the SPP footprint are presented in Figure 167.

Figure 167. SPP footprint and regional transmission interface limits

Source: Commercial third-party database provider; EPA data; LEI analysis.

In the subsequent sections, LEI focused on the KSMO zone, which was the focus of the modeling and outputs. Historical zonal prices suggest there is little to no spread between the wholesale prices for this region, consistent with transmission limits and utility load zones in this region of SPP's footprint. Thus, LEI believes it is reasonable to model these regions as one zone. Figure 168 below shows the zonal prices for these regions, showing the spread between the historical Westar zone ("WR") and KCP&L zone ("KCPL") is below 5% in all years.

[701] Includes the entirety of Oklahoma and parts of Arkansas, and Texas.

[702] Includes parts of New Mexico, Texas and Oklahoma.

Figure 168. Historical SPP zonal prices in Kansas and Missouri (2015-2019 YTD)

Source: Commercial third-party database provider.

13.1 Fuel price projections

13.1.1 Natural gas

Natural gas price assumptions are based on OTC Global Holdings ("OTCGH") Henry Hub projections in the near term, relying on forwards markets for projected locational gas prices. Long-term natural gas projections are based on the 2019 EIA Annual Energy Outlook ("AEO"). For the first year of the forecast period (2020), LEI has used the three-month average forwards (January to March 2019). Beyond 2020, LEI has conducted a fundamentals analysis, using a reference point plus a transportation adder and local distribution charges.

LEI employed its proprietary Levelized Cost of Pipeline ("LCOP") model to forecast the gas price spread between Henry Hub and modeled gas pricing points. Figure 169 illustrates LEI's gas price projection for El Paso San Juan hub, which is used as a proxy for gas prices of resources located in the Kansas region.

The LCOP model evaluates thirty gas pricing hubs in North America by tracking forward basis differentials and the levelized cost of building new pipeline(s) between each hub. The cost of pipeline capacity in the model relies on data collected from FERC on actual and proposed pipeline projects. In the long run, price spreads between two gas pricing hubs are assumed not to exceed the levelized cost of building a new pipeline between the two hubs. This levelized cost therefore effectively sets a long-term price cap on the transportation cost adder or basis differential between two pricing hubs.

Figure 169. LEI's gas price projection for El Paso San Juan (2020-2029)

Source: LEI analysis.

13.1.1.1 Coal

Despite its recent decline, coal remains an essential fuel in SPP, historically comprising half of the total generation. Given the diversity in coal sourcing, quality, and price, we developed plant-specific coal price outlooks. We began with an estimate of recent actual delivered costs, taking into account the type of coal used at each plant (since each coal plant has different Sulphur content levels and different contracts for price and transportation), and escalated that estimate with the longer-term trends for the commodity (the coal price forecast) and inflation rate from EIA's Annual Energy Outlook 2019.

13.1.2 Generic new entry

In the longer term, we assume that generators make "just-in-time" capacity investment decisions that are timed to load growth, as we are targeting a sufficient reserve margin on top of peak load. Renewable new entry is synchronized to meet the renewable portfolio standards set by state regulators. Load serving entities in SPP are required to have a planning reserve margin of 12%,[703] and we assume this as a benchmark check on a SPP-wide basis. In several SPP states, a hybrid industry structure dominates the market, and utilities are still rate-regulated for generation. Most new entry is likely to be utility-built under a cost-of-service regime for reliability targets, as described in their IRP.

In our modeling, we also consider retirements. Plants are assumed to choose to exit the market if their energy market revenues cannot cover the minimum going forward fixed costs three years in a row, consistent with economically rational business behavior. Nuclear retirements take place after 60 years, provided the plant has its generating license renewed by the Nuclear Regulatory Commission ("NRC") and ageing thermal plants (coal and natural gas) are generally retired after 60 years as well – this age-based retirement serves as a proxy rule for ageing technology over the

[703] SPP defines 'capacity margin' as follows: {(total capacity-peak demand)/total capacity}; Source: *Southwest Power Pool Criteria*: April 25, 2011.

longer-term horizon, over and above the announced retirements by utility resource plans. This age-based rule is consistent with SPP modeling practice, with its long-term transmission planning employing a similar retirement rule.[704]

Figure 170 presents New Entry Trigger Price ("NETP") assumptions for a new generation resource. The NETP sets a long-run, effective cap on energy prices, such that energy prices may exceed NETP only for so long as it takes for price signals to be recognized and trigger the construction cycle of a new unit. As seen below, the least cost new technologies in SPP are CCGT and onshore wind.

Figure 170. Cost of generic new entry assumptions for SPP, 2019

[2018 dollars]	CCGT	SCGT (Frame)	Scrubbed Coal	Nuclear	Onshore Wind	Solar PV	Biomass
Capital cost ($/kW)	797	1,127	5,419	5,926	1,432	1,601	3,761
Leverage	60%	60%	60%	60%	70%	70%	60%
Debt interest rate	6%	6%	6%	6%	6%	6%	6%
Tax rate	26%	26%	26%	26%	26%	26%	26%
Pre-tax required equity return	12.5%	12.5%	15.0%	10.0%	10.0%	10.0%	15.0%
Debt financing term (years)	20	10	20	20	20	20	20
Equity contribution capital recovery term (years)	20	20	20	20	20	20	20
Construction time (months)	36	24	48	72	36	18	36
Heat rate (Btu/kWh)	6,200	9,800	11,650	10,461	-	-	13,500
Nominal variable O&M ($/MWh)	2.1	11.0	9.9	2.4	-	-	5.7
CO2 content (lb/MMBtu)	120	120	210	-	-	-	-
Carbon cost ($/ton)							
CO2 adder ($/MWh)	-	-	-				
Nominal fixed O&M ($/kW/year)	10.3	7.0	83.8	101.3	48.4	22.5	114.4
Capacity factor	60%	25%	90%	90%	30%	15%	85%
Fuel price ($/MMBtu)	1.6	1.6	2.0	0.5	-	-	1.5
All-in fixed cost ($/kW-yr)	$96.9	$164.3	$736.1	$750.1	$186.0	$169.1	$555.8
Levelized non-fuel cost of new entry ($/MWh)	$20.5	$86.0	$103.3	$97.5	$70.8	$128.7	$80.3
Levelized cost of new entry ($/MWh)	**$30.6**	**$101.9**	**$127.0**	**$102.7**	**$70.8**	**$128.7**	**$100.6**
carrying charge until commissioning, $/kW	$97	$92	$882	$1,447	$175	$98	$459
amortized carrying charge over debt term, $/kW/year	$7	$11	$65	$107	$13	$7	$34
debt-financed portion, $/kW	$478	$676	$3,251	$3,556	$1,002	$1,121	$2,257
annual debt repayment, $/kW/year	$35	$84	$241	$263	$74	$83	$167
equity-financed portion, $/kW	$319	451	2,168	2,370	430	480	1,504
annual equity return, $/kW/year	$44	$62	$346	$278	$50	$56	$240

Note: All-in fixed cost includes interest and principal debt payments and fixed O&M.
Sources: EIA AEO 2018; LEI.

[704] SPP. *2019 Integrated Transmission Planning Assessment Report.* November 2019. P. 23

14 Appendix E: Overview of forecasting methodology

For the wholesale energy prices outlook, we employed our proprietary simulation model, POOLMod, as the foundation for our electricity price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least-cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 171. POOLMod's two-stage process

POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation on the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing).

Also, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network.

15 Appendix F: About London Economics International LLC

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm's roots stem from the initial round of privatization of electricity, gas, and water companies in the UK in the late 1980s. Since then, LEI has advised private sector clients, market institutions, and government on policy initiatives, market and tariff design, asset valuation, market power, and strategy in virtually all deregulated markets worldwide.

The following attributes make LEI unique:

- ***clear, readable deliverables*** grounded in substantial topical and quantitative evidence
- ***extensive experience in regulatory filings*** provides expertise to advise on network tariffs and design rates under PBR
- ***wealth of knowledge of energy and infrastructure regulation*** worldwide to provide expert testimony services on regulatory best practices and innovation
- ***balance of private sector and governmental clients*** enables us to advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions
- ***Boston-based firm*** with in-depth knowledge of energy policies and regional issues
- ***worldwide experience*** backed by multilingual and multicultural staff.

CERTIFICATE OF SERVICE

20-GIME-068-GIE

I, the undersigned, certify that a true and correct copy of the above and foregoing Notice of Filing of Rate Study was served via electronic service this 8th day of January, 2020, to the following:

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