AUSTIN ENERGY'S	§	**BEFORE THE CITY OF AUSTIN**
2022 BASE RATE REVIEW	§	
	§	**IMPARTIAL HEARING EXAMINER**

REBUTTAL TESTIMONY

OF

MARK DOMBROSKI

ON BEHALF OF AUSTIN ENERGY

JULY 7, 2022

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark Dombroski. My business address is 4815 Mueller Blvd, Austin, Texas.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by the City of Austin (City) as Deputy General Manager, Chief Financial and Administrative Officer of Austin Energy.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Austin Energy.

Q. DID YOU PREPARE THIS TESTIMONY?

A. Yes. This testimony was prepared by me or under my direct supervision.

Q. PLEASE DISCUSS BRIEFLY YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL EXPERIENCE, AND QUALIFICATIONS.

A. I am currently the Deputy General Manager, Chief Financial and Administrative Officer for Austin Energy where I am responsible for finance, technology and data, corporate services, and employee development. I have been with Austin Energy since October 2014 with continuous responsibility as Chief Financial Officer. I had similar responsibilities while serving as the Director of Finance for Seattle City Light. In addition to my public power experience, I have nearly 20 years of experience in providing financial and economic advisory services, principally in the energy and utility industry, with the firms of Price Waterhouse LLP and KPMG LLP as well as a smaller consulting firm. I have a Bachelor of Arts degree from the University of Texas at Dallas and a Master of Public Administration degree from Seattle University. I am a Certified Energy Manager with the Association of Energy Engineers.

Q. HAVE YOU PROVIDED AN ATTACHMENT THAT DETAILS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. I provide this information in Exhibit MD-1 of my testimony.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. The purpose of my rebuttal testimony is to respond to various revenue requirement, revenue allocation, and rate design proposals contained in the Participants' position statements and rebuttal testimonies including the Independent Consumer Advocate (ICA), Coalition for Clean, Affordable & Reliable Energy (CCARE), NXP, Texas Industrial Energy Consumers (TIEC), Two Women Ratepayers (2WR), Sierra Club, Public Citizen, and Solar United Neighbors (SCPC/SUN), Mr. Paul Robbins, and Homeowners United for Rate Fairness (HURF). Additionally, I summarize the adjustments Austin Energy has made to its requested revenue requirement since the initial filing and to provide the updated line loss study report that was utilized in Austin Energy's Base Rate Filing Package.

II. SCOPE AND SUMMARY OF REBUTTAL TESTIMONY

Q. DID PARTICIPANTS TAKE EXCEPTION TO AUSTIN ENERGY'S PROPOSED REVENUE REQUIREMENT?

A. Yes. There are 14 Participants in Austin Energy's Base Rate Review. Of those Participants, ten filed statements of position, and six took exception to Austin Energy's proposed revenue requirement. Those adjustments ranged from $11 million to $41.7 million.[1]

Q. DO YOU AGREE WITH THE PROPOSED ADJUSTMENTS MADE TO THE REVENUE REQUIREMENT BY THE PARTICIPANTS?

A. No, with limited exception as discussed below. While each of the Participants' proposed adjustments is more specifically addressed by other Austin Energy witnesses in their testimonies, I also take the position that the majority of the Participants' arguments are unreasonable.

Q. PLEASE EXPLAIN YOUR POSITION.

A. Austin Energy's last base rate increase was an increase of 6.4% in 2012, which was a decade ago. In fact, Austin Energy's last base rate change was in 2017, when it reduced rates by 6.7%. As a result, Austin Energy had a combined net loss of $90 million in Fiscal Years (FY) 2020 and 2021. Additionally, since Austin Energy's last ratemaking test year, FY 2014, prices, as measured monthly by the Consumer Price Index for All Urban Consumers: Fuels and Utilities from the St Louis Federal Reserve, have increased 16.5% while rates have remained unchanged. In the last twelve months alone, prices have increased 15%. Based on the Cost-of-Service Study using test year FY 2021, Austin Energy proposed a $48 million base rate increase in its Base Rate Filing Package.[2]

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[1] Coalition for Clean, Affordable, and Reliable Energy's (CCARE) Statement of Position at 1 (Jun. 22, 2022); Direct Testimony of Billie S. LaConte, on behalf of Texas Industrial Energy Consumers (TIEC) at 2- 3 (Jun. 22, 2022); NXP Statement of Position at 5 (Jun. 22, 2022); and Independent Consumer Advocate's (ICA) Party Position Statement at 1 (Jun. 22, 2022). Please note that some Participants made recommendations to the revenue requirement without associating dollar amount impacts.

[2] Austin Energy Base Rate Filing Package at 46 (Apr. 18, 2022) (RFP).

As a result of Austin Energy's current financial condition, on June 28, 2022, Fitch Credit Ratings downgraded Austin Energy from 'AA' to 'AA-'.[3] Fitch cited Austin Energy's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage.[4] Fitch's AA- rating assumes that Austin Energy's proposed $48 million increase is adopted.[5]

Acceptance of the majority of the Participants' adjustments to the revenue requirement would accelerate the deterioration of Austin Energy's financial position, further increase Austin Energy's leverage, decrease Austin Energy's operating cash flow, force Austin Energy to expend its cash and reserves, and increase its debt.

Q. WHAT ARE THE LIMITED ADJUSTMENTS THAT AUSTIN ENERGY HAS MADE TO ITS REQUESTED REVENUE REQUIREMENT?

A. As discussed further in the rebuttal testimonies of Austin Energy witnesses Rabon and Gonzalez, the following adjustments were made to the proposed revenue requirement, reducing the request to $35.7 million:

- Non-Cash Nuclear Decommissioning—As identified in the testimony of David Effron, Austin Energy agrees that a correction to the non-cash portion of the nuclear decommissioning contribution should be made. The original adjustment to this contribution was intended to remove the non-cash portion of this expense, given Austin Energy is using the cash flow approach to the development of its revenue requirement. However, Austin Energy erroneously

[3] Exhibit MD-2 at 1.

[4] *Id*.

[5] *Id*.

reversed the sign convention on the non-cash portion and increased the cash obligation, rather than decreasing the cash obligation. Specifically, Austin Energy increased the cash needs by $4,662,375 when it should have decreased the cash needs by $4,662,375. Thus, the overall impact was $4,662,375 times two, or $9,324,751, as suggested in Mr. Effron's testimony.

- Interest on Nuclear Decommissioning—In addition to the non-cash adjustment to the nuclear decommissioning cost, Austin Energy also determined that a portion of the cash contribution was funded from interest on the nuclear decommissioning trust. Given that interest income on the trust was not included as a source of revenue to offset the cash needs of the utility, as it was assumed to accrue in the trust (see Work Paper C-3.4.1), Austin Energy should not have included this portion of the cash funding for nuclear decommissioning in the revenue requirement. Removing the portion of the cash contribution that came from interest income results in an additional $2,594,248 reduction to the revenue requirement as compared with what Austin Energy originally filed.
- BAB Subsidy—Austin Energy determined that the interest expense on the Series 2010B Build America Bond refunding was missing the subsidized portion in Austin Energy's original analysis. The subsidy was included as a source of funding in the analysis (see Work Paper C-3.4.1), but the interest expense the subsidy was offsetting was missing because the debt service used was net of the subsidy. Thus, Austin Energy has added the subsidy portion of the interest expense to the revised analysis. The subsidy portion was $1,849,557 in FY 2021 and $1,791,095 in FY 2022.

- Functionalize New Service Connection Revenues—As discussed in the testimony of Grant Rabon, Austin Energy agrees with Mr. Johnson's suggestion that new service connection revenues should be functionalized to customer, rather than demand.
- As discussed in the rebuttal testimony of Austin Energy witness Gonzalez, Austin Energy proposes a known and measurable adjustment of $1,154,575 to late payment fees.
- GFT Impacts—Based on the adjustments above, the calculated GFT was reduced from $121 million to $120 million.

Q. WHAT APPENDIX TO THE BASE RATE FILING PACKAGE IS AUSTIN ENERGY UPDATING?

A. Appendix D, Austin Energy System Loss Study for FY 2018. Exhibit MD-7 Line Loss Study contains the correct version of Austin Energy's System Loss Study for FY 2018 (Line Loss Study). Austin Energy inadvertently attached a preliminary version of its Line Loss Study as Appendix D to its 2022 Base Rate Filing Package submitted on April 18, 2022. Austin Energy amended its filing on June 6, 2022, with the attached document that is the correct, final Line Loss Study. Austin Energy relied on the attached Line Loss Study when proposing its 2022 Base Rate Filing Package. Therefore, the Amendment has no impact on the Cost-of-Service Study or Base Rate Filing Package.

Q. WHAT GUIDANCE DOES AUSTIN ENERGY USE FOR DETERMINING RATE DESIGN?

A. Austin Energy uses Bonbright's criteria for determining rate design as laid out in the following questions:

1. Does the rate provide adequate revenue recovery to the utility?
2. Does the rate promote fairness in cost allocation (equity between customer classes)?
3. Does the rate promote efficient resource use?
4. Is the rate practical to implement?
5. Is the rate easy to interpret?
6. Does the rate provide revenue stability for the utility?
7. Does the rate provide bill stability for customers?
8. Does the rate avoid undue discrimination among customers?[6]

Q. DID INTERVENORS TAKE EXCEPTION TO AUSTIN ENERGY'S PROPOSED RATE DESIGN?

A. Yes. The exact arguments made by Participants varied and will be specifically addressed in detail in other witnesses' rebuttal testimony. However, Austin Energy found there to be two basic arguments on residential base rate design: (1) to leave the rate design unchanged,[7] or (2) to make only a minor change to the current base rate design.[8]

Q. DO YOU AGREE WITH THE PARTICIPANTS' PROPOSED RESIDENTIAL BASE RATE DESIGN ALTERNATIVES?

A. No. Austin Energy's current residential base rate design is based on a 2009 test year, and residential consumption has changed greatly over the past 13 years. In this period, the number of customers with kWh consumption in lower tiers, priced below cost-of-

[6] James C. Bonbright, et al, *Principles of Public Utility Rates* (2d. ed. 1988).

[7] Direct Testimony of Ezra D. Hausman, Ph.D., on behalf of Sierra Club, Public Citizen, and Solar United Neighbors (SCPC/SUN) at 4 (Bates 6) (Jun. 22, 2022) (Hausman Direct); Position Statement of Paul Robbins at 6 (Jun. 22, 2022) (P. Robbins Position Statement); and Two Women Ratepayers' (2WR) Position Statement at 10 (Jun. 22, 2022) (2WR Position Statement).

[8] Initial Presentation of Clarence L. Johnson, on behalf of ICA at 72 (Jun. 22, 2022) (Johnson Presentation).

service, has increased. This change in consumption renders Austin Energy's current residential rate design ineffective. Therefore, Austin Energy is proposing fundamental changes the customer charge and the residential tier structure to address the deficiencies of the current residential base rate design.

Q. SEVERAL PARTIES, INCLUDING THE ICA,[9] PAUL ROBBINS,[10] AND 2WR[11] TAKE ISSUE WITH THE PROPOSED REDESIGN OF THE CURRENT FIVE-TIER RATE STRUCTURE. WHAT IS YOUR RESPONSE?

A. These Participants fail to acknowledge the reality of the changing consumption patterns occurring within Austin Energy's service area. Regarding Austin Energy's proposed change to the residential tiered rate structure, Figures 7-24 and 7-25 in the Base Rate Filing Package illustrate the change in consumption patterns.[12] Today, because of changes in technology, building codes, and other factors, customers are using less energy, on average, than when the current rate structure was designed. As a result, more energy sales are occurring in tiers that are below cost, without sufficiently offsetting sales in higher tiers. With fewer higher-usage customers, Austin Energy's ability to collect adequate revenue is negatively impacted. For this reason, a change in rate design is required.

To simplify its rate structure, create a more equitable rate structure, and address the inability of tier subsidization to accomplish revenue stability, Austin Energy proposes moving all residential customers to three tiers and increasing the customer

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9 Johnson Presentation at 57-74.

10 P. Robbins Position Statement at 1-2.

11 2WR Position Statement at 7-10.

12 RFP at 102.

charge.[13] Austin Energy also adjusted the consumption levels of the three tiers to better reflect current customer usage patterns. Figure 7-31 of the Base Rate Filing Package illustrates Austin Energy's proposed changes.[14]

Austin Energy incurs significant costs that do not vary with the sale of energy. Those costs are recovered in base rates. However, the current base rate design overly relies on energy sales to generate the appropriate level of revenue. Austin Energy addresses this by proposing to increase the customer charge and reducing the rates charged in the residential tiers. Austin Energy witness Brian Murphy also addresses these issues.

Q. DO YOU AGREE WITH PARTICIPANTS WHO HAVE ARGUED THAT THE CURRENT RESIDENTIAL BASE RATE DESIGN, WHICH INCLUDES STEEP TIER PRICING, IS NECESSARY TO ENCOURAGE ENERGY EFFICIENCY?[15]

A. No. Under Austin Energy's proposed residential base rate design, high use customers who use more energy will continue to have higher bills, sending price signals to customers. The current inside-city five-tier residential rate structure creates price distortion by sending incorrect pricing signals, resulting in poor economic decisions for both high and low use customers. In addition, Austin Energy's analysis shows that customers do not respond to tiered pricing signals.[16] Finally, using energy-based (kWh)

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[13] *Id*. at 109.

[14] *Id*. at 110.

[15] Johnson Presentation at 70-73; Hausman Direct at 7 (Bates 9).

[16] RFP at 87-96.

tiered rates is misaligned with the fixed costs actually recovered in base rates. Austin Energy recovers variable energy costs in the Power Supply Adjustment.

Q. DO YOU AGREE WITH PARTICIPANTS WHO HAVE ARGUED THAT THE PROPOSED RESIDENTIAL RATE DESIGN UNFAIRLY IMPACTS LOW USAGE CUSTOMERS?[17]

A. No. Work Paper H-3.1.1 in the Base Rate Filing Package shows inside city residential customers in the first residential tier (0 - 500kWh) range from 90% to 183% below cost-of-service, which correlates to more than 40% of residential customers being subsidized.[18] As discussed further in my testimony below, these proposals are not consistent with current customer usage, continue subsidies within tiers and thus are not based on cost, and do not provide fair and equitable rates.

Q. DO YOU AGREE WITH PARTICIPANTS WHO CONTEND THAT LOW INCOME CUSTOMERS ARE NEGATIVELY IMPACTED BY THE PROPOSED AUSTIN ENERGY RESIDENTIAL RATE DESIGN?[19]

A. No. Austin Energy's research into usage patterns of customers enrolled in the Customer Assistance Program (CAP) indicates that these customers, on average, use more energy than non-CAP customers.[20] In addition, CAP customers do not pay the customer charge. Therefore, the higher customer charge (which CAP customers would not pay) and lower volumetric rates would be a benefit to CAP customers, as compared to the current rate structure.

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[17] Johnson Presentation at 71; Hausman Direct at 13 (Bates 15).

[18] RFP at 289.

[19] Hausman Direct at 13 (Bates 15); P. Robbins Position Statement at 1-3.

[20] RFP at 105-109.

Q. HOW WOULD YOU CHARACTERIZE AUSTIN ENERGY'S RESIDENTIAL BASE RATE PROPOSAL?

A. Austin Energy's residential base rate proposal is compliant with its financial policies[21] and bond covenants and is consistent with ratemaking principles, including gradualism. The higher customer charge decouples fixed-cost recovery from kWh sales, which are not sufficient to recover fixed-costs under the current tier structure. The new tier structure better reflects current customer consumption, while continuing to send efficiency signals. The proposal also reduces intra- and interclass subsidies, enhances revenue stability, and reduces customer bill volatility.

III. BASE RATE REVIEW PROCESS

Q. SEVERAL PARTIES, INCLUDING THE ICA,[22] SCPC/SUN,[23] 2WR,[24] PAUL ROBBINS,[25] AND NXP,[26] COMPLAIN ABOUT THE BASE RATE REVIEW PROCESS, ARGUING GENERALLY THAT ADDITIONAL TIME AND TRANSPARENCY IS NEEDED. WHAT IS YOUR RESPONSE?

A. Austin Energy's Base Rate Review process is unique among municipally owned utilities (MOUs) and affords the Participants the ability to thoroughly analyze Austin Energy's proposal. Notably, Austin Energy filed a native copy of the Cost-of-Service model with the Base Rate Filing Package, eliminating the need for Participants to request the model through discovery and the associated delay. Discovery began

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[21] *See* Exhibit MD-2.

[22] Johnson Presentation at 6.

[23] Direct Testimony of Cyrus Reed, Ph.D., on behalf of SCPC and SUN at 11 (Bates 13) (Jun. 22, 2022) (Reed Direct).

[24] 2WR Position Statement at 1-3.

[25] P. Robbins Position Statement at 1.

[26] NXP Statement of Position, Testimony of James W. Daniel at 12-14 (Jun. 22, 2022).

April 18, 2022, giving Participants more than two months to ask questions and receive responses before filing Position Statements on June 22, 2022. Additionally, Austin Energy reduced the discovery response time from the traditional 20-day deadline used at the Public Utility Commission of Texas to a 14-day deadline to facilitate faster transfer of information. In addition, Austin Energy held two Technical Conferences to allow additional opportunities for discovery. Finally, Austin Energy agreed to an extension of the original deadline for discovery and Position Statements to allow Participants more time to ask additional questions and receive information. The procedural schedule addresses the timing constraints of City Council, the Impartial Hearing Examiner (IHE), the Participants, and Austin Energy. Arguments that the process was not fair or transparent, or that different procedural rules are needed, should be rejected.

IV. REVENUE REQUIREMENT

A. Heavy Equipment Lease

Q. HAS AUSTIN ENERGY MADE AN ADJUSTMENT TO THE REVENUE REQUIREMENT BASED ON THE HEAVY EQUIPMENT LEASE FROM ALTEC?

A. Yes. Austin Energy made a known and measurable adjustment of $7,421,233 to the revenue requirement for the heavy equipment lease in its Base Rate Filing Package.[27]

Q. HAS ANY PARTICIPANT PROPOSED AN ADJUSTMENT TO THIS KNOWN AND MEASUREABLE ADJUSTMENT?

[27] RFP at 39.

A. Yes. ICA witness Effron proposes a downward adjustment of $7,344,072 based on FY 2022 costs.[28]

Q. DO YOU AGREE WITH MR. EFFRON'S PROPOSED ADJUSTMENT?

A. No. Austin Energy's known and measurable adjustment is based on a fully executed lease agreement with Altec and current extensions awaiting City Council approval in September. The Altec lease has been the historical method for which Austin Energy acquires heavy equipment for operations and has been utilized since 2007. Austin Energy's adjustment meets known and measurable criteria as set out in the executed contracts and extensions. City Council has approved Altec lease extensions since the execution of the first lease agreement. The City Council approves operating budgets on an annual basis.

B. <u>General Fund Transfer</u>

Q. WHAT IS THE GENERAL FUND TRANSFER (GFT)?

A. The General Fund Transfer (GFT) is an annual transfer of revenue from Austin Energy to the City of Austin's General Fund as authorized by Texas Government Code § 1502.059. The GFT is calculated and determined during the City's budget process. The GFT is based on 12% of Austin Energy's three-year average revenues using the current year estimate and the previous two years' actual revenues less power supply and district cooling revenues. The GFT is not based on earnings, margins, or profits.[29]

Q. DO ANY PARTICIPANTS PRESENT ARGUMENTS REGARDING THE GFT IN THEIR POSITION STATEMENTS?

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[28] Initial Presentation of David J. Effron, on behalf of ICA at 10 (Jun. 22, 2022).

[29] Appendices to RFP at 21.

A. Yes. CCARE, HURF, 2WR, NXP, and TIEC present arguments regarding the GFT.

Q. DO AUSTIN ENERGY FINANCIAL POLICIES PROVIDE FOR A GFT?

A. Yes, Austin Energy's Financial Policies 12, 13, and 17 provide for and prescribe how the GFT is determined.[30] Austin Energy's Financial Policies are approved by City Council.

Q. HISTORICALLY, HAS AUSTIN ENERGY MADE A GFT TO THE CITY?

A. Yes. In accordance with state law, Austin Energy has made a GFT since at least 1946.

Q. DO YOU AGREE WITH 2WR'S STATEMENT THAT SAYS THE COST ELEMENTS INCLUDED IN THE CUSTOMER CHARGE ARE OVERSTATED BECAUSE THEY INCLUDE A PROFIT?[31]

A. No. The GFT is a cost to Austin Energy and not a profit. Cost elements become revenue requirement and are therefore included the GFT calculation. As the revenue requirement increases, so does the amount of the GFT. For further discussion, please see Austin Energy witness Grant Rabon's rebuttal testimony.

Q. WHAT IS YOUR RESPONSE TO HURF'S RELIANCE ON THE SETTLEMENT IN PUBLIC UTILITY COMMISSION DOCKET NO. 40627 TO ARGUE THAT OUTSIDE-CITY CUSTOMERS SHOULD NOT BE SUBJECT TO THE GFT?

A. The settlement in Docket No. 40627[32] was a negotiated, "black-box" settlement that did not specifically address the GFT. The rate reduction provided to the outside-city

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[30] RFP at 21.

[31] 2WR Position Statement at 9-10.

[32] *Petition By Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627, Final Order (Apr. 29, 2013).

customers was through a general reduction to the revenue requirement, not through a reduction in GFT. Therefore, HURF's proposed reductions to rates for outside-city customers should be rejected.

Q DO YOU AGREE WITH HURF'S STATEMENT OF POSITION ASSERTION THAT THE GFT SHOULD NOT APPLY TO OUTSIDE CITY CALCUATIONS?[33]

A. No. The GFT is calculated in accordance with Austin Energy's Financial Policy 12.[34] Since revenue from outside city customers is included in the calculation of the GFT, cost causation dictates that outside-city customers are allocated their share of this cost. Texas Government Code § 1502.059, which specifically authorizes the transfer of revenue of any municipally owned utility system to the municipality's general fund, does not distinguish between inside and outside-city customers.

Q. DO YOU AGREE WITH HURF'S STATEMENT THAT OUTSIDE-CITY CUSTOMERS DERIVE NO BENEFIT FROM THE CITY OF AUSTIN'S EXPENDITURES OF THOSE FUNDS?[35]

A. No. While Austin Energy believes that all customers benefit from services resulting from the GFT, there is no requirement that Austin Energy be required to demonstrate any direct benefit to customers. Additionally, HURF has provided no evidence to support its position that outside-city customers derive no benefit from the City's expenditure of the GFT.

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[33] HURF Statement of Position at 1 (Jun. 22, 2022).

[34] RFP at 21.

[35] HURF Statement of Position at 1.

Q. DO YOU AGREE WITH CCARE'S, NXP'S, AND TIEC'S ADJUSTMENT TO REDUCE THE GFT?

A. No. This will be addressed further in the rebuttal testimony of Austin Energy witness Grant Rabon.

C. Contributions in Aid of Construction (CIAC)

Q. DOES AUSTIN ENERGY INCLUDE CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC) IN ITS REVENUE REQUIREMENT?

A. Yes. CIAC reduces the revenue requirement as found in Schedule C-3 and the associated workpapers in the Base Rate Filing Package.[36]

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT 2WR'S STATEMENT. "2WR HAS YET TO RECEIVE ANSWERS TO HOW AE BOOKS AND TRACKS THE CIAC FUNDED CAPITAL OR HOW IT IS TREATED IN COST OF SERVICE?"[37]

A. Austin Energy responded to this question at both the second technical conference[38] and in its response to 2WR RFI 3-7.[39] Furthermore, Austin Energy discusses CIAC and its impact to rates in Section 4.2.2 of the Base Rate Filing Package.[40]

Q. PARTICIPANT 2WR ASKS THE IHE TO RECOMMEND THAT COUNCIL DIRECT AUSTIN ENERGY TO TRACK ITS CAPITAL PAID FOR WITH

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36 Appendices to RFP at 86, 93-94, 97-98.

37 2WR Position Statement at 3.

38 Austin Energy's Responses to Questions Related to Technical Conference #2 at 22-24 (Bates 53-55) (May 27, 2022).

39 Austin Energy's Response to 2WR Third Request for Information at 48 (Jun. 22, 2022).

40 RFP at 31.

CIAC FOR PURPOSES OF RATE SETTING AND THAT THE IHE RECOMMEND CITY COUNCIL TO DIRECT THE ELECTRIC UTILITY COMMISSION TO SUPERVISE A STUDY ADDRESSING GROWTH.[41] **ARE THESE RECOMMENDATIONS NECESSARY?**

A. No. City Council adopted a resolution in 2014 (City Council Resolution No. 20140612-057) directing the City Manager to "plan for full cost recovery of line extensions, with an exception for certain affordable housing," which Austin Energy has done. Additionally, at its June 13, 2022 meeting, the Electric Utility Commission (EUC) had an extensive discussion regarding the CIAC policy and the allocation of system growth costs and voted that City Council should review the CIAC policy and Austin Energy should provide a presentation to the EUC regarding the CIAC policy. Therefore, 2WR's recommendations are unnecessary as the EUC will be reviewing the CIAC policy over the next few months and making recommendations to City Council on possible revisions.

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT PAUL ROBBINS' POSITION THAT AUSTIN ENERGY IS NOT FOLLOWING THE INTENT OF COUNCIL'S POLICY TO HAVE GROWTH PAY FOR ITSELF?[42]

A. Mr. Robbins is mis-characterizing City Council Resolution No. 20140612-057. Austin Energy's CIAC policy as reflected in the design manual requires collection of 100% of the costs for line extensions and new infrastructure associated with requests for new electric service, with an exemption for certain affordable housing. A customer applying for new service will be charged all estimated costs for labor and material

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[41] 2WR Position Statement at 3.

[42] P. Robbins Position Statement at 11.

required to modify existing infrastructure and to extend service from Austin Energy's existing infrastructure to the customer's point of service to serve the requested load. This includes the service drop and meter.

Mr. Robbins has provided no evidence that Austin Energy is not following the intent of City Council.

D. Town Lake Center (TLC) Property

Q. WHAT IS THE TLC PROPERTY?

A. TLC is a commercial building on Barton Springs Road that Austin Energy purchased in 1989 and used as a headquarters building. In April 2021, Austin Energy acquired a new building in the Mueller Development to use as a headquarters. Austin Energy continues to maintain certain information technology equipment at TLC, but I expect that equipment to be moved in late summer or early fall of 2022.

Austin Energy anticipates that it will transfer TLC to the City of Austin Financial Services Division (FSD) in FY 2023 but has not finalized the terms of the transfer nor executed a memorandum of understanding for the transfer.

Q. DID AUSTIN ENERGY MAKE AN ADJUSTMENT TO THE REVENUE REQUIREMENT FOR THE PROCEEDS FROM THE POTENTIAL SALE OF TLC?

A. No.

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT 2WR'S PROPOSAL TO AMORTIZE $30.5 MILLION IN PROCEEDS FROM THE SALE OF TLC TO THE CITY OVER FIVE YEARS AS AN OFFSET TO BASE RATE COST OF SERVICE, ALLOCATED TO CUSTOMER CLASSES BASED ON THE

METHODOLOGY AUSTIN ENERGY UTILIZED IN ALLOCATING COSTS RELATED TO TLC IN THE LAST BASE RATE CASE?[43]

A. Austin Energy and FSD have not entered into or agreed to a memorandum of understanding for the sale and transfer of TLC. That memorandum would specify the amortization period, interest rate, and payment schedule. Therefore, it does not meet the criteria of a known and measurable adjustment. If an adjustment would be made as a result of the proceeds, then a reduction would be made to internally generated funds for construction in Schedule C-3. Austin Energy has removed all operating costs of TLC from the revenue requirement and therefore no costs have been allocated in the base rate case.

E. Biomass Plant

Q. DID AUSTIN ENERGY MAKE AN ADJUSTMENT FOR THE NACOGDOCHES POWER PLANT?

A. No. Costs associated with the Nacogdoches power plant are not included in the base rates. They are recovered through the Power Supply Adjustment, which is outside the scope of this rate review.

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT PAUL ROBBINS' PROPOSAL THAT RECOMMENDATIONS FOR LOWERING THE COST OF THE NACOGDOCHES POWER PLANT NEED TO BE ANALYZED?[44]

A. Paul Robbins has not recommended any specific adjustments. The purpose of the rate review is not to explore whether gains in efficiency for specific power generation assets are attainable. As noted above, this issue is outside the scope of this rate review.

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[43] 2WR Position Statement at 5.

[44] P. Robbins Position Statement at 11.

A. <u>Capital Investments in Fayette Power Plant</u>

Q. DID AUSTIN ENERGY INCLUDE OPERATING AND CAPITAL COSTS FOR FAYETTE POWER PROJECT (FPP) IN ITS REVENUE REQUIREMENT?

A. Yes. Austin Energy is a partial owner of FPP with the Lower Colorado River Authority (LCRA). Austin Energy has attempted to exit FPP, but so far has been unable to reach a mutual agreement with LCRA to do so. Therefore, obligations under the City's participation agreement with LCRA continue.

Q. DO YOU AGREE WITH SCPC/SUN THAT THESE COSTS SHOULD BE DISALLOWED BASED ON UNREASONABLENESS AND IMPRUDENCE?[45]

A. No. It appears that this recommended disallowance is based more on environmental policy rationale as opposed to applying appropriate ratemaking principles. This assumption is consistent with a statement attributed to Public Citizen in an Austin Monitor article dated July 1, 2022.[46]

Until Austin Energy is able to exit its share of FPP, Austin Energy has obligations under the Participation Agreement with LCRA.[47] FPP is operational and provides benefits to Austin Energy customers and the ERCOT grid. Costs to operate and maintain FPP included in the revenue requirement are reasonable and necessary based on ratemaking and cost recovery principles and should be approved.

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[45] Hausman Direct at 24-25 (Bates 26-27).

[46] *See* https://www.austinmonitor.com/stories/2022/07/environmental-advocates-say-fayette-coal-plant-is-poisoning-residents-push-city-to-test-water/.

[47] Exhibit MD-5.

B. Credit Rating and Debt Service Coverage Ratio

Q. TIEC WITNESS LACONTE TAKES ISSUE WITH AUSTIN ENERGY'S CREDIT RATING AD DEBT SERVICEC COVERAGE.[48] WHAT IS YOUR RESPONSE?

A. Witness LaConte demonstrates a misunderstanding of how an MOU operates as related to its credit rating and debt service coverage.

Q. HOW DOES AUSTIN ENERGY DETERMINE ITS RATES?

A. Austin Energy's rates are calculated in accordance with the Austin Energy Financial Policies and bond covenants.[49] Austin Energy uses the cash flow methodology as outlined in Section 4.2 of the Base Rate Filing Package.[50]

Q. DOES AUSTIN ENERGY SET RATES TO ACHIEVE A CERTAIN LEVEL OF CREDIT RATING?

A. No. While Austin Energy had a 'AA' Credit rating from Fitch until recently,[51] it was a result of prudent management and favorable market conditions and not a product of applying criteria for a specific credit rating in its ratemaking. On June 28, 2022, Fitch downgraded Austin Energy to 'AA-'. Fitch cited Austin Energy's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising

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[48] Direct Testimony of Billie S. LaConte, on behalf of Texas Industrial Energy Consumers (TIEC) at 6-10 (Jun. 22, 2022) (LaConte Direct).

[49] Appendices to RFP at 20-22.

[50] RFP at 28-29.

[51] Appendices to RFP at 575.

leverage.[52] Fitch's 'AA-' rating assumes that Austin Energy's proposed $48 million revenue requirement increase is adopted.[53]

Q. DOES AUSTIN ENERGY SET RATES TO ACHIEVE A SPECIFIC DEBT SERVICE COVERAGE RATIO?

A. Yes, but only under specific circumstances. Financial Policy 6 stipulates that Austin Energy sets its rates using the cash flow methodology which shall produce a minimum of a 2.0x debt service coverage;[54] however, Austin Energy made no adjustment to increase or decrease the proposed revenue requirement to achieve a specific level of debt service coverage.

Q. DID ANY PARTICIPANTS COMPARE AUSTIN ENERGY'S CREDIT RATING TO OTHER UTILITIES?

A. Yes. TIEC witness LaConte compares Austin Energy's credit rating to four vertically-integrated investor-owned utilities (IOUs).[55] Witness LaConte further states that Austin Energy is seven rungs above investment grade status with a credit rating much higher than these four vertically-integrated IOUs.[56]

Q. IS WITNESS LACONTE'S COMPARISON OF AUSTIN ENERGY CREDIT RATINGS WITH IOUS APPROPRIATE?

A. No. Austin Energy is an MOU and not an IOU. MOUs and IOUs have very distinct capital structures. Austin Energy does not have access to equity investments that IOUs

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[52] Exhibit MD-2 at 1.

[53] *Id*.

[54] Appendices to RFP at 20.

[55] LaConte Direct at 6.

[56] *Id*. at 7.

enjoy. MOUs rely upon cash from retail rates and the sale of long-term debt (bonds) to fund capital needs. Therefore, the credit rating on debt is much more critical for an MOU than an IOU.

Q. DO YOU AGREE WITH WITNESS LACONTE'S ARGUMENT THAT IT IS NOT PRUDENT FOR AUSTIN ENERGY TO HAVE 'AA' RATING?[57]

A. No. Austin Energy sets its rates in accordance with its Financial Policies and bond covenants. However, Austin Energy's former 'AA' rating was well within the norm of retail public power providers according to the Fitch Peer Review.[58] There are 80 total retail public power providers in the Fitch 2021 peer review.[59] Of those 80, 51 or 64% are rated between 'AA+' to 'AA-', with 21 being 'AA'.[60] There are only eight or 10% retail public providers with ratings between 'A-' and 'BBB',[61] which is the range of LaConte's IOUs.

Q. DOES WITNESS LACONTE ACKNOWLEDGE THAT A LOWER CREDIT RATING WILL RESULT IN A HIGHER DEBT SERVICE COST?

A. Yes. According to witness LaConte's calculation, if Austin Energy were downgraded to an 'A' rating, Austin Energy's annual debt service cost would increase by $3.6 million per year.[62]

Q. WHAT ARE OTHER IMPACTS OF A LOWER CREDIT RATING?

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[57] LaConte Direct at 7-8.

[58] Appendices to RFP at 572-599.

[59] *Id*. at 576-580.

[60] *Id*.

[61] *Id*.

[62] LaConte Direct at 8.

A. A lower credit rating will increase the cash collateral requirements on Austin Energy from its energy trading counterparties. A lower credit rating may also impact the favorable terms and conditions in vendor contracts.

Q. DID WITNESS LACONTE PROVIDE A DEBT SERVICE COVERAGE RATIO?

A. Yes. Witness LaConte provides a calculation in Table 4 of her testimony.[63]

Q. DO YOU AGREE WITH THAT CALCULATION?

A. Yes. That calculation is provided in Austin Energy's Response to TIEC RFI 3-3.[64]

Q. DID WITNESS LACONTE MODIFY THE DEBT SERVICE COVERAGE CALCULATION?

A. Yes. Witness LaConte removes non-electric revenue and expenses to propose a debt service coverage calculation of 2.50x.[65]

Q. DO YOU AGREE WITH THIS MODIFICATION?

A. No. Austin Energy uses revenue bonds for its capital financing. Those bonds are secured by all of Austin Energy's revenues, regardless of source. Therefore, it is inappropriate to exclude a source of revenue and its associated expenses from the debt service coverage ratio calculation.

Q. ARE THERE OTHER METHODS TO CALCULATE DEBT SERVICE COVERAGE?

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[63] *Id*.

[64] Austin Energy's Response to TIEC's Third Request for Information at 5 (Jun. 6, 2022).

[65] LaConte Direct at 9.

A. Yes. Austin Energy's methodology to calculate debt service coverage is consistent with and complies with its Financial Policies and bond covenants. However, credit rating agencies, such as Fitch, make additional adjustments, and it is well within their discretion to do so.

Q. IS IT APPROPRIATE FOR WITNESS LACONTE TO COMPARE HER PROPOSED 2.5X DEBT SERVICE COVERAGE TO FITCH'S RANGE OF 0.90X -3.96X?[66]

A. No. First, Witness LaConte's comparison is an apples-to-oranges calculation. Her proposed debt service coverage calculation is inappropriate because it does not include all revenues and expenses as discussed above. Second, Fitch makes adjustments to its debt service coverage ratio that include items such as power purchase agreements and transfers.[67]

Q. DOES AUSTIN ENERGY USE THE DEBT SERVICE COVERAGE RATIO FROM THE FITCH REPORT TO DETERMINE THE REVENUE REQUIREMENT?

A. No. As stated previously, Austin Energy's rates are calculated in accordance with Austin Energy's Financial Policies and bond covenants.[68]

Q. WHAT DOES WITNESS LACONTE RECOMMEND?

A. Witness LaConte recommends that Austin Energy's return is unnecessarily high by calculating a return on equity and compare that to regulated entities as a benchmark.

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[66] LaConte Direct at 10.

[67] Appendices to RFP at 572-599.

[68] Appendices to RFP at 20-22.

Specifically, Witness LaConte calculates a 12.0% return on equity versus a benchmark of 9.38%.[69]

Q. DO YOU AGREE WITH WITNESS LACONTE'S PROPOSED RETURN ON EQUITY COMPARISON?

A. No. Witness LaConte admits Austin Energy does not earn a return on equity.[70] Therefore, her argument is flawed. Austin Energy provides an implied return on rate base of 7.9% using the cash flow methodology.[71]

Q. IS IT APPROPRIATE TO COMPARE AUSTIN ENERGY TO AN IOU?

A. No. Witness LaConte's methodology is based on IOU methodology, which has a different capital structure than an MOU.

Q. DO YOU AGREE WITH WITNESS LACONTE'S PROPOSED REDUCTIONS TO THE GFT AND INTERNALLY GENERATED FUNDS TO LOWER THE DEBT SERVICE COVERAGE RATIO?[72]

A. No. For further discussion, see my testimony on GFT and Austin Energy witness Grant Rabon's testimony on internally generated funds.

V. <u>REVENUE STABILITY</u>

Q. DO YOU AGREE WITH SCPC/SUN WITNESS HAUSMAN'S CONCERN FOR REVENUE STABILITY?

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69 LaConte Direct at 10.

70 *Id*.

71 Appendices to RFP at 35.

72 LaConte Direct at 10-11.

A. No. Witness Hausman demonstrates a fundamental misunderstanding of Austin Energy's business model as an MOU.

Q. WHAT IS YOUR RESPONSE TO WITNESS HAUSMAN'S ARGUMENT THAT REDUCING THE INCENTIVE FOR CUSTOMERS TO SAVE ENERGY IMPROVES FINANCIAL PREDICTABILITY BECAUSE IT WILL ULTIMATELY SELL MORE KWH AND HAVE A MORE PREDICTABLE REVENUE STREAM?[73]

A. Austin Energy is an MOU, with no shareholders. It sets rates to recover only its costs and not to maximize shareholder value. If Austin Energy's rates generate excess revenue, that cash is used as working capital and future rates would be reduced, as happened in 2017 when Austin Energy lowed its base rates by 6.7%.

Q. WHAT IS YOUR RESPONSE TO WITNESS HAUSMAN'S ARGUMENT THAT BY RELYING MORE ON FIXED CUSTOMER CHARGES, THE UTILITY TRANSFERS RISK FROM ITS SHOULDERS ONTO THOSE OF ITS CUSTOMERS—AT THE SAME TIME ELIMINATING THE CUSTOMERS' ABILITY TO REDUCE COSTS THROUGH GOOD ENERGY DECISION-MAKING?[74]

A. Austin Energy is an MOU; all risks and rewards are borne by the customers. Austin Energy is tasked with managing risks on behalf of its customers. In its proposal, Austin Energy is moving residential rates closer to cost of service[75] to send the appropriate price signals to customers for good energy decision-making. The current inside-city

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[73] Hausman Direct at 21.

[74] *Id*.

[75] RFP at 130.

five-tier residential rate structure creates price distortion by sending incorrect pricing signals, resulting in poor economic decisions for both high and low use customers. The majority of residential kWh sales for the current residential rate structure occur in the first two tiers, which are below cost of service, and may lead to under investment in energy efficiency options or opportunities for those customers.[76]

Q. DOES WITNESS HAUSMAN'S TESTIMONY PRIORITIZE SUCCESSFUL ENERGY EFFICIENCY OVER STABILITY AND FINANCIAL HEALTH IN RESIDENTIAL RATE DESIGN?[77]

A. Yes.

Q. DO YOU AGREE WITH THIS TESTIMONY?

A. No. Witness Hausman focuses on energy efficiency and does not adequately consider other important rate design tenets such as effectively yielding the total revenue requirements and providing stable revenues. Austin Energy must set rates to comply with its Financial Policies and bond covenants.[78] In setting these rates, Austin Energy follows standard ratemaking principles as stated in the Base Rate Filing Package. One of these principles is to ensure the long-run financial strength of the utility.[79] Revenue stability refers to maintaining adequate revenues and cash flow to meet costs on a year-to-year basis. Ongoing revenue stability is a key principle in ratemaking throughout the electric utility industry, as addressed by James C. Bonbright in his Principles of Public Utility Rates.[80]

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[76] RFP at 111.

[77] Hausman Direct at 21.

[78] RFP at 20-22.

[79] *Id*. at 6-10.

[80] James C. Bonbright, et al, *Principles of Public Utility Rates* at 383 (2d. ed. 1988).

Q. DOES AUSTIN ENERGY'S PROPOSAL IN THIS PROCEEDING BALANCE THESE POLICIES FOR ENSURING THE LONG-RUN FINANCIAL STRENGTH AND STABILITY OF THE UTILITY?

A. Yes. While Austin Energy's current rates and tariff structures do not support the long-run financial strength and stability of the utility, as evident in the reasoning for the Fitch downgrade, Austin Energy's proposed rates and tariff structures in this filing provide a more definitive solution toward the long-run financial strength and stability of the utility as well as promoting energy efficiency.

Q. HAS AUSTIN ENERGY ADDRESSED THE DEFICIENCIES RESULTING FROM THE CURRENT RATES AND TARIFF STRUCTURE AND THE ADVANTAGES OF THE PROPOSED RATES AND TARIFF STRUCTURES OUTLINED IN THIS PROCEEDING?

A. Yes. As shown in Austin Energy's Base Rate Filing Package, current rates and tariff structures do not support the long-run financial strength and stability of the utility on an ongoing basis. Changes, specifically to the residential rate design, are required that will support the continued viability of Austin Energy to meet current and future obligations. This has been addressed in the Base Rate Filing Package in detail.[81]

VI. RATE DESIGN

A. Outside the City Residential Rates

Q. DOES AUSTIN ENERGY PROPOSE TO MAINTAIN SEPARATE RATES FOR OUTSIDE THE CITY RESIDENTIAL CUSTOMERS?

A. No.

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[81] RFP, Introduction at 10-11, 78-108; RFP, Chapter 7–Rate Design at 78-124.

Q. DO ANY PARTICIPANTS RECOMMEND MAINTAINING SEPARATE RATES FOR OUTSIDE THE CITY RESIDENTIAL CUSTOMERS?

A. Yes. Both HURF and the ICA make recommendations would result in separate rates for outside the city residential customers. HURF's recommendation was discussed earlier in my testimony.

ICA witness Johnson proposes to maintain the current rates for outside the city customers because the rate proposal could be perceived as unfair by inside the city customers.[82]

Q. DO YOU AGREE WITH MR. JOHNSON'S PROPOSAL?

A. No. Austin Energy proposes a single residential class which applies to all electric service for domestic purposes in each individual metered residence, apartment unit, mobile home, or other residential dwelling unit as classified by City Code or Ordinance whose point of delivery is at secondary voltage less than 12,470 volts nominal line to line located within Austin Energy's service territory and does not distinguish by geographical location. Mr. Johnson's proposal is not cost-based, not fair, not equitable, and is discriminatory. Based on Mr. Johnson's testimony, he provides no evidence that Austin Energy's proposed single residential rate structure is unfair to inside the city residential customers, other than an apparent preference for subsidization of inside the city residential customers by outside the city residential customers. In addition, leaving outside the city residential customers unchanged would violate cost causation principles used in ratemaking.

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[82] Johnson Presentation at 69.

B. Residential Rate Design - Tiers

Q. DOES AUSTIN ENERGY RECOMMEND A CHANGE TO THE RESIDENTIAL RATE STRUCTURE?

A. Yes. Austin Energy is proposing several changes as noted in its Base Rate Filing Package in Section 7.3. Those changes include increasing the customer charge from $10 to $25 per month, combining inside and outside the city residential rates into a single rate structure, and modifying the rate structure to three tiers.[83]

Q. DO ANY PARTICIPANTS OBJECT TO AUSTIN ENERGY'S PROPOSED RESIDENTIAL RATE STRUCTURE?

A. Yes. ICA witness Johnson, SCPC/SUN witness Hausman, Participant Paul Robbins, and Participant 2WR object to Austin Energy's proposed residential rate structure. I will address each Participants' arguments individually below.

Q. WHAT ARE ICA WITNESS CLARENCE JOHNSON'S RECOMMENDATIONS CONCERNING AUSTIN ENERGY'S PROPOSED RESIDENTIAL RATE STRUCTURE?

A. ICA witness Clarence Johnson recommends maintaining current outside the city rates.[84] I disagree with his proposal. Please refer to my testimony above for discussion on outside the city rates.

Witness Johnson also recommends not adopting Austin Energy's $25 customer charge for inside the city customers.[85] I disagree with this proposal. Please see Austin

[83] RFP at 109-111.

[84] Johnson Presentation at 69.

[85] *Id*. at 67.

Energy witness Brian Murphy's testimony for further discussion on the customer charge.

Witness Johnson also objects to Austin Energy's proposed three-tier rate structure and instead recommends a four-tier rate structure[86] and posits the following:

- Austin Energy objects because the five-tier rate structure has been too effective at promoting energy conservation.[87]
- Austin Energy ignores any potential long-run reductions in utility cost which accompanies reduction in energy consumption.[88]
- The effort to restructure the residential rates is likely to increase future electricity consumption.[89]
- Significantly increasing rates for low usage customers and significantly decreasing rates for high usage customers runs counter to promoting energy conservation.[90]

Q. DO YOU AGREE WITH MR. JOHNSON'S TESTIMONY THAT AUSTIN ENERGY STATES ITS FIVE-TIER RATE STRUCTURE HAS BEEN TOO EFFECTIVE AT PROMOTING ENERGY CONSERVATION?[91]

A. No. Austin Energy conclusively demonstrated in the Base Rate Filing Package that Austin Energy customers do not respond to tiered pricing as outlined in Section 7.2.[92]

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[86] Johnson Presentation at 72.
[87] *Id*. at 67.
[88] *Id*.
[89] *Id*. at 68.
[90] *Id*. at 71.
[91] *Id*. at 67.
[92] RFP at 87-96.

In fact, witness Johnson admits that "most customers probably do not track their usage against tier levels."[93] Witness Johnson further states "However, over time customers may become aware that their total electric bill is too high and become more inclined to engage in energy efficiency activities…"[94] Austin Energy agrees with this statement. In Austin Energy's proposed rates, customers who have higher consumption will pay higher bills, and those bills will be price signals for those customers.

Because customers do not respond to the five-tier structure, tiered rates do not necessarily contribute to energy conservation. For further discussion on energy conservation, see Austin Energy Witness Brian Murphy's testimony.

Q. WHAT IS YOUR RESPONSE TO WITNESS JOHNSON'S CLAIM THAT AUSTIN ENERGY IGNORES ANY POTENTIAL LONG-RUN REDUCTIONS IN UTILITY COST WHICH ACCOMPANIES REDUCTION IN ENERGY CONSUMPTION?[95]

A. This claim is untrue and irrelevant. Austin Energy's revenue requirement is based upon test year 2021 costs. Any future reductions in utility costs would be captured in future rate reviews.

Q. WHAT IS YOUR RESPONSE TO WITNESS JOHNSON'S ASSERTION THAT THE EFFORT TO RESTRUCTURE THE RESIDENTIAL RATES IS LIKELY TO INCREASE FUTURE ELECTRICITY CONSUMPTION?[96]

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[93] Johnson Presentation at 71.

[94] *Id.*

[95] *Id*. at 67.

[96] *Id*. at 68.

A. It is speculative, unproven, and contrary to Austin Energy's findings. First, witness Johnson has provided no proof that Austin Energy's proposed rate structure would increase electricity consumption. Second, as noted above, Austin Energy has conclusively proven that customers do not respond to tiered rate levels. Third, average residential consumption year-over-year has declined even after Austin Energy reduced residential rates in 2017. Fourth, Austin Energy demonstrated in Figure 7.12 in the Base Rate Filing Package that customers outside the City of Austin with three tiers had the same level of average reduction in consumption as customers inside the City of Austin who had five tiers. Fifth, Austin Energy's proposed rate structure still includes inclining tiers to recognize gradualism in ratemaking.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ASSERTION THAT SIGNIFICANTLY INCREASING RATES FOR LOW USAGE CUSTOMERS AND SIGNIFICANTLY DECREASING RATES FOR HIGH USAGE CUSTOMERS RUNS COUNTER TO PROMOTING ENERGY CONSERVATION?[97]

A. No. First, high usage customers will continue to receive higher bills than low usage customers sending an effective price signal. Second, as noted above, Austin Energy has conclusively proven that customers do not respond to tiered rate levels, and witness Johnson has not proven that customers do respond to tiered pricing levels. Third, promoting energy conservation should not produce rates that are unfair, inequitable, discriminatory, and require high-use customers to subsidize low-use customers.

Q. WHAT IS WITNESS JOHNSON'S PROPOSED TIER STRUCTURE?

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[97] *Id*. at 71.

A. Witness Johnson proposes a four-tiered rate structure with a lower customer charge.[98] Witness Johnsons states "an inverted block rate structure can create more year-to-year revenue volatility than an energy rate structure with fewer blocks."[99]

Q. DO YOU AGREE WITH WITNESS JOHNSON'S PROPOSED RATES?

A. No. I disagree with witness Johnson's revenue requirement and thus do not agree with witness Johnson's proposed rates. In addition, witness Johnson's proposal is problematic because it expands Austin Energy's proposed first tier of 0-300 kWh to 0-500 kWh. Witness Johnson's first tier thus encompasses 2,080,119 bills generated, or 37% of total bills in the test year.[100] This encompasses too large percentage of bills for the first tier because this first tier would need to be well below the cost of service to create an inclined block of four tiers.

Witness Johnson's proposed second tier price is more than double his proposed first tier price,[101],[102] requiring higher usage customers to subsidize a significant portion of customer bills. Inadequate cost recovery from low usage customers is further exacerbated by witness Johnson's proposed low customer charge. The significant difference between witness Johnson's proposed first and second tier rates jeopardizes cost recovery and revenue stability and has been proven to be ineffective in sending price signals, as discussed earlier in my testimony.

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[98] *Id.* at 72.

[99] *Id*.

[100] Appendices to RFP at 284.

[101] Tier 2 price of 0.06200 divided by Tier 1 price of 0.02850 equals 2.18.

[102] Johnson Presentation at 73.

Q. WHAT ARE WITNESS HAUSMAN'S RECOMMENDATIONS CONCERNING AUSTIN ENERGY'S PROPOSED RESIDENTIAL RATE STRUCTURE?

A. Witness Hausman recommends Austin Energy's proposed residential customer charge and revisions to the five-tier residential rate structure be rejected.[103] Witness Hausman further recommends the City Council direct Austin Energy to develop and file an alternative rate plan[104] that retains a rate structure that provides a strong incentive for energy efficiency and customer-sited distributed generation, that is protective of vulnerable customers, and allows those who have already implemented beneficial practices and technologies to continue to recoup their investments through reduced energy costs.[105]

Additionally, witness Hausman recommends Austin Energy be directed to develop and propose a Time-of-Use rate option for customers who wish to further control their energy use and costs in ways that provide overall system benefits.[106]

Q. WHAT IS YOUR RESPONSE?

A. Austin Energy's proposed rate design addresses all of the elements listed above. Chapter 7 of Austin Energy's Base Rate Filing Package provides multiple extensive analyses supporting our proposal.[107]

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[103] Hausman Direct at 4 (Bates 6).

[104] *Id*.

[105] *Id*. at 12 (Bates 14).

[106] *Id*. at 4 (Bates 6).

[107] RFP at 78-130.

Additionally, witness Hausman does not refute any analyses provided in each of these sections, nor does he provide any of his own analyses to support his recommendations.

Q. WHAT DOES WITNESS HAUSMAN BASE HIS RECOMMENDATION ON?

A. Witness Hausman disagrees with Austin Energy's proposed customer charge.[108] Witness Hausman agrees that certain customer-related costs, such as meters, interconnections, and billing are essentially fixed on a per-customer basis, but does not believe this to be a reasonable characterization of capacity costs over time.[109] Witness Hausman believes one of the great benefits of energy efficiency, customer-sited solar, and demand response is that they can delay, reduce, or eliminate the need for system expansion and distribution investments.[110] He also asserts that once these investments are made they become sunk costs that cannot be avoided.[111]

Q. DO YOU AGREE?

A. I agree with the premise of Witness Hausman's argument, but not his conclusion. Austin Energy has provided an embedded cost of service and witness Hausman's own testimony on sunk costs supports Austin Energy's position of a higher customer charge. Witness Hausman states "once these investments are made they become sunk costs that cannot be avoided".[112] The very costs that witness Hausman cites that are sunk are included in the cost of service model and both warrant and support higher customer

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[108] Hausman Direct at 10 (Bates 12).

[109] *Id*.

[110] *Id*. at 11 (Bates 13).

[111] *Id*.

[112] *Id*.

charges. Any future savings to customer charges would be reflected in future embedded cost of service studies.

Q. DO YOU AGREE WITH WITNESS HAUSMAN'S RECOMMENDATION TO LEAVE THE CURRENT RATE DESIGN INTACT?

A. No. I will address the tier structure and Austin Energy witness Brian Murphy addresses the customer charge component.

Witness Hausman states customers with high energy usage would receive a decrease in their monthly bills, as the per-kWh cost of energy falls by more than half, overwhelming the proposed increase in the fixed charge,[113] but witness Hausman never defines what low usage customers and high usage customers are.

Austin Energy provides a detailed analysis comparing its customers' usage characteristics between 2009, when the current rate structure was developed, and 2021, the current test year.[114] That analysis demonstrates that the definition of low usage and high usage customers must be redefined in the tier structures. Figure 7-2 in the Base Rate Filing Package demonstrates how the definition of low usage and high usage customers has changed over time.[115] A customer consuming 500 kWh today would be more representative of average consumption and not a low usage customer as in the past. As can be seen in Figure 7-2, today's low usage customer is more properly defined as a customer consuming 300 kWh or less.[116] Austin Energy's proposed tier

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[113] *Id*. at 18 (Bates 20).

[114] RFP at 78-86.

[115] *Id*. at 80.

[116] *Id*.

structure for the first tier includes customers with 0-300 kWh consumption.[117] A typical customer falls under Austin Energy's proposed tier structure for the second tier with consumption between 301-1200 kWh.[118] Finally, a high usage customer falls under Austin Energy's proposed tier structure for the third tier with consumption of greater than 1200 kWh.[119]

Witness Hausman's recommendation to maintain the current tier structure is not consistent with current customer usage, continues subsidies between tiers and thus is not based on cost, and does not provide fair and equitable rates. Workpaper H-3.1.1 shows customers consuming 251 to 500 kWh are currently 90% below cost to serve which correlates to over 40% of those residential customers being subsidized.[120]

Q. DOES WITNESS HAUSMAN LINK AUSTIN ENERGY'S TIERED RATE STRUCTURE TO INVESTMENTS IN ENERGY EFFICIENCY?

A. Yes. Witness Hausman states "[c]ustomers must have an incentive to invest in energy-saving equipment and to adopt energy-saving practices and must be confident that their investments will be more than repaid over a reasonable period of time through energy savings."[121]

Q. DOES WITNESS HAUSMAN'S PROPOSAL TO MAINTAIN EXISTING TIER STRUCTURES SEND ACCURATE PRICE SIGNALS?

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[117] *Id*.

[118] *Id*.

[119] *Id*.

[120] Appendices to RFP at 289.

[121] Hausman Direct at 19 (Bates 21).

A. No. As I previously discussed, the current inside-city five-tier residential rate structure creates price distortion which sends incorrect pricing signals resulting in uneconomic decisions for both high and low use customers in energy efficiency investments.

Q. DOES WITNESS HAUSMAN DISPUTE THAT THE CURRENT RESIDENTIAL RATE STRUCTURE NEGATIVELY IMPACTS VULNERABLE CUSTOMERS?

A. Yes. Witness Hausman argues that Austin Energy does not support its claim, "low-income CAP customers may use more energy on average than other customer" because Austin Energy compares only average usage for CAP and non-CAP customers and did not consider, for example, the number of customers at each consumption level.[122]

Q. DO YOU AGREE?

A. No. Witness Hausman is incorrect. Figure 7-28 in the Base Rate Filing Package shows that CAP customers consume more energy on average between 2012 and 2020.[123] Additionally, Figure 7-29 shows the percent of consumption (measured by customer bills) at each tier under current rates for CAP and non-CAP customers,[124] which addresses specifically the point that Witness Hausman claims that Austin Energy did not provide.

Q. DID WITNESS HAUSMAN PROVIDE ANY EVIDENCE TO SUPPORT HIS CLAIM?

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[122] Hausman Direct at 13 (Bates 15).

[123] RFP at 106.

[124] RFP at 107.

A. Yes. Witness Hausman requested the data supporting Figures 7-28 and 7-29 in SCPC 3-1 as stated in footnote 12,[125] but did not request any guidance on how to interpret the data. Witness Hausman misinterprets the data labels as erroneous, when in fact he eliminates customers who consume a large amount of energy. Additionally, witness Hausman eliminates bills he characterized as negative bills when in fact they were bill corrections. By eliminating this data, witness Hausman's results are invalid and inaccurate. For further discussion, see the testimony of Austin Energy witness Brian Murphy.

Q. DOES WITNESS HAUSMAN PROPOSE AUSTIN ENERGY CONSIDER A TIME-OF-USE RATE OPTION FOR CUSTOMERS?

A. Yes. Witness Hausman proposes Austin Energy be directed to develop and propose a time-of-use rate option for customers who wish to further control their energy use and costs in ways that provide overall system benefits.[126]

Q. WHAT IS YOUR RESPONSE?

A. Austin Energy currently offers multiple time-of-use rates: a load-shifting rider to all commercial customer classes and the EV360 pilot program. In addition, Austin Energy offers other forms of time-of-use options to both residential and commercial customers. Austin Energy's current residential time-of-use pilot program opened in 2017 and is open to 100 customers. There is only one residential customer currently enrolled, while other customers elected to exit their participation in the pilot program.

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[125] Hausman Direct at 16 (Bates 18).

[126] *Id*. at 4 (Bates 6).

Austin Energy continues to seek opportunities to develop feasible rate options that benefit Austin Energy customers but does not support what witness Hausman proposes.

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT PAUL ROBBINS' RECOMMENDATIONS THAT ANY RESIDENTIAL RATE INCREASE ULTIMATELY DETERMINED TO BE NECESSARY BE APPORTIONED ON THE SAME BASIS AS THE CURRENT RATE?[127]

A. By apportioning any increase to the current rate structure, tier subsidies are exacerbated, rates move further away from cost to serve, and are neither fair nor equitable.

Q. WHAT IS YOUR RESPONSE TO PARTICIPANT 2WR'S RECOMMENDATION THAT NO ADJUSTMENTS BE MADE TO THE RESIDENTIAL RATE STRUCTURE?[128]

A. 2WR's arguments in support of their recommendation have been addressed in my testimony above.

VII. CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. Yes. Austin Energy has proposed rates that are consistent with its Financial Policies and bond covenants, adhere to traditional industry ratemaking principles, and improve bill stability for all our customers. Our proposal is supported by rigorous data analyses using actual data from our operations and customers. The proposed rate design is

[127] P. Robbins Position Statement at 6.

[128] 2WR Position Statement at 10.

consistent with the most recent customer consumption patterns. The need for an increase in revenue is evident in the recent financial trends experienced by Austin Energy and is validated by an external, independent review of Fitch Credit Rating on June 28, 2022.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit MD-1 - Resume

RESUME OF MARK DOMBROSKI

OCTOBER 2014 – PRESENT
DEPUTY GENERAL MANAGER, CHIEF FINANCIAL & ADMINISTRATIVE OFFICER, AUSTIN ENERGY
Reporting to the General Manager and operating with a high level of autonomy, I provide leadership, oversight, and strategic direction for support operations of Austin Energy including Finance, Technology and Data, Employee Development, and Corporate Support Services functions. I have the fiduciary responsibility for administering all financial proceedings of Austin Energy.

My specific duties, functions, and responsibilities include:
- Provides overall leadership and direction of Austin Energy’s financial and administrative functions.
- Responsible for Austin Energy’s financial performance, including the alignment of revenues with costs, effective use of capital, and the prudent management of risk.
- Oversees the timely and accurate recording and reporting of all financial transactions for Austin Energy in accordance with all applicable regulations and policies.
- Plans, deploys, manages, and ensures the security of strategic data and technology resources in support of Austin Energy’s operations and customer needs.
- Responsible for the effective and efficient planning and management of the Employee Development and Corporate Support Services to enable and enhance the overall performance of Austin Energy.
- Accountable for the effective and efficient planning, management, and development of the Austin Energy financial and administrative functions workforce with an emphasis on diversity, equity, and inclusion.
- Responsible for representing Austin Energy in all matters of interest with governmental and regulatory agencies, boards, councils, commissions, and joint partnership oversight bodies.
- Advises the General Manager and other executives on matters pertaining to financial and administrative functions and ensures all functions are operating together effectively to achieve the strategic initiatives and goals.
- Assumes Austin Energy General Manager duties and responsibilities in their absence.

JULY 2020 – DECEMBER 2020
INTERIM CHIEF FINANCIAL OFFICER, CITY OF AUSTIN
I had the fiduciary responsibility for administering all financial proceedings of the City government, except for the assessment and collection of taxes, while overseeing the operations of the City's Financial Services Department, including the Budget, City Controller's Office, Purchasing, and Treasury. Member of the Board of Directors for the Austin Economic Development Corporation.

APRIL 2018 – AUGUST 2018
INTERIM CHIEF OPERATING OFFICER, AUSTIN ENERGY
I was responsible for the generation, transmission, and distribution of electricity and energy market operations, Information Technology (IT), district cooling and energy, strategic planning, and emerging technology functions.

JANUARY 2016 – AUGUST 2016
INTERIM GENERAL MANAGER, AUSTIN ENERGY
Interim General Manager, January 2016 – August 2016. I was responsible for providing leadership and direction for all Austin Energy operations.

NOVEMBER 2009 – OCTOBER 2014
VICE PRESIDENT, THE REHANCEMENT GROUP, INC.
Served as the VP for Energy and Utilities for a consulting firm based in the Washington, DC metro area. Responsible for all business development, client relations, and technical services for the company in the energy and utility sector. My focus was on energy and utility economics, privatization, ratemaking and intervention, capital planning, asset management, and regulatory analysis. The primary market was federal agencies and facilities.

APRIL 2008 – OCTOBER 2009
CITY MANAGER, BAINBRIDGE ISLAND, WA
Served as both a City Administrator and City Manager for a full-service municipal corporation, guiding the City in the transition from Mayor/Council form of government to a Council/Manager in a highly charged political environment while experiencing significant financial challenges. Responsible for the operations of the public works, (wet) utilities, finance, human resources, planning, information technology, and public safety departments with over 150 employees and an annual budget of $55M.

JUNE 2005 – APRIL 2008
DIRECTOR OF FINANCE, SEATTLE CITY LIGHT
Responsible for providing strategic leadership for all aspects of a $900 million annual budget preparation and reporting, rate making, financial planning, debt management, and corporate performance for Seattle City Light, a public power utility with more than $3B in its rate base and serving 380,000 retail customers in western Washington with 1,900 MW of clean hydro and wind power.

MARCH 1992 – JUNE 2005
CONSULTANT, MANAGER, SENIOR MANAGER, AND DIRECTOR, PUBLIC ACCOUNTING AND FINANCIAL ADVISORY SERVICES
Performed financial, accounting, and economic consulting for large infrastructure and energy-related projects, such as commercial land developments, refineries, and power plants. Duties included business valuation, complex financial modeling, economic analysis, crisis management, and business turnaround services. Firms included Crossroads, LLC, KPMG Consulting, KPMG LLP, and Price Waterhouse, LLP.

JUNE 1988 –MARCH 1992 (RESERVES 1992 – 1998)
MILITARY OFFICER, UNITED STATES MARINE CORPS
Planned, organized, and supervised military combat operations and training exercises. Responsible for the training and welfare of over 100 personnel as an Executive Officer of a combat unit. Assigned as an Operations Officer for 2,500 personnel stationed aboard five ships in the Mediterranean Sea.

EDUCATION
Master of Public Administration, Seattle University
Bachelor of Arts, Economics and Political Economy, The University of Texas at Dallas

CERTIFICATIONS
Certified Energy Manager (CEM) Credential ID 18785, Association of Energy Engineers
Certified Demand Side Manager (CDSM) Credential ID 1447, Association of Energy Engineers

Exhibit MD 2 - Austin Energy Financial Policies (last approved FY 2022 Budget)

1. The term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years.

2. Capitalized interest shall only be considered during the construction phase of a new facility if the construction period exceeds seven years. The time frame for capitalizing interest may be three years but not more than five years. Council approval shall be obtained before proceeding with financing that includes capitalized interest. Note: Austin Energy does not use capitalized interest.

3. Principal repayment delays shall be one to three years, but shall not exceed five years.

4. Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated (AAA) bond insurance companies, a funded debt service reserve, or a combination of both for its existing revenue bond issues, in accordance with the Combined Utility Systems Revenue Bond Covenant.

5. A debt service reserve fund shall not be required to be established or maintained for the Parity Electric System Obligations so long as the “Pledged Net Revenues” of the System remaining after deducting the amounts expended for the Annual Debt Service Requirements for Prior First Lien and Prior Subordinate Lien Obligations is equal to or exceeds 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations. If the “Pledged Net Revenues” do not equal or exceed 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations, then a debt service reserve fund shall be established and maintained in accordance with the Supplemental Ordinance for such Parity Electric System Obligations.

6. Debt service coverage of a minimum of 2.0x shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations will be included at 1.0x. Note: Debt service coverage for the FY 2017-18 Budget is 4.1x.

7. Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and materials inventories. The term of short-term debt will not exceed five years. Both tax-exempt and taxable commercial paper may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy. Total short-term debt shall generally not exceed 20% of outstanding long-term debt.

8. Commercial paper may be used to finance capital improvements required for normal business operation for electric system additions, extensions, and improvements or improvements to comply with local, State and Federal mandates or regulations. However, this shall not apply to new nuclear generation units or conventional coal generation units. Commercial paper will be converted to refunding bonds when dictated by economic and business conditions. Both tax-exempt and taxable refunding bonds may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy. Commercial paper may be used to finance

voter approved revenue bond projects before the commercial paper is converted to refunding bonds.

9. Ongoing routine, preventive maintenance should be funded on a pay-as-you-go basis.

10. Austin Energy shall maintain a minimum quick ratio of 1.50 (current assets less inventory divided by current liabilities). The source of this information should be the Comprehensive Annual Financial Report.

11. Austin Energy shall maintain a minimum operating cash equivalent (also known as Working Capital) of 60 days of budgeted operations and maintenance expense, less power supply costs, plus the amount of additional monies required to bring the sum of all Austin Energy's reserves to no less than 150 days of operating and maintenance expense.

12. Net revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements. Once these obligations have been met, any remaining net revenues will be deposited in the following order into Austin Energy’s reserve funds until each reserve reaches its minimum funding level: Working Capital, Contingency Reserve, Power Supply Stabilization Reserve, and then Capital Reserve. The sum of the four reserves shall be the cash equivalent of no less than 150 days of operating and maintenance expense.

13. The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years’ actual revenues less power supply costs and on-site energy resource revenue from the City's Comprehensive Annual Financial Report.

14. Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.

15. The Capital Reserve shall be created and established for providing extensions, additions, replacements, and improvements to the electric system. The Capital Reserve shall maintain a minimum cash equivalent of 50% of the previous year's electric utility depreciation expense.

16. The Contingency Reserve shall be created and established for unanticipated or unforeseen events that reduce revenue or increase obligations, such as costs related to a natural disaster, extended unplanned plant outages, insurance deductibles, or unexpected costs created by Federal or State legislation. The Contingency Reserve may be used to fund unanticipated power supply expenses only after the Power Supply Stabilization Reserve has been fully depleted. The Contingency Reserve shall maintain an operating cash equivalent of 60 days of budgeted operations and maintenance expense, less power supply costs. In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted funding level within two fiscal years.

17. Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support (1) the full cost (direct and indirect) of operations including depreciation, (2) debt service, (3) General Fund transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve accounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, if applicable, and (7) any other current obligations. In addition, Austin Energy may recommend to Council in the budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies and other Austin Energy requirements such as working capital. In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds. A rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study.

18. A decommissioning trust shall be established external to the City to hold the proceeds for monies collected for the purpose of decommissioning the South Texas Nuclear Project. An external investment manager may be hired to administer the trust investments.

19. The master ordinance of the Parity Electric System Obligations does not require a debt service reserve fund. Austin Energy will maintain a minimum of unrestricted cash on hand equal to six months debt service for the then outstanding Parity Electric System Obligations.

20. Current revenue, which does not include the beginning balance, will be sufficient to support current expenditures (defined as “structural balance”). However, if projected revenue in future years is not sufficient to support projected requirements, ending balance may be budgeted to achieve structural balance.

21. A Non-Nuclear Plant Decommissioning Fund shall be established to fund plant retirement. The amount set aside will be based on a decommissioning study of the plant site. Funding will be set aside over a minimum of four years prior to the expected plant closure.

22. The Power Supply Stabilization Reserve shall be created and established for mitigating power supply cost volatility which causes frequent variation in the Power Supply Adjustment. The Power Supply Stabilization Reserve shall maintain a cash equivalent of 90 days of net power supply costs. Net power supply costs shall be defined as costs eligible for inclusion in the Power Supply Adjustment. The Power Supply Stabilization Reserve shall be funded using net revenues after meeting other obligations and consistent with the flow of funds schedule.

FitchRatings

28 JUN 2022

Fitch Downgrades Austin, TX Electric Utility System Rev Bonds to 'AA-'; Outlook Stable

Fitch Ratings - Austin - 28 Jun 2022: Fitch Ratings has downgraded the following electric utility system revenue bonds issued by the City of Austin, TX to 'AA-' from 'AA':

--$1.9 billion electric utility system revenue and revenue refunding bonds;

--$50.3 million combined utility systems (prior subordinate lien) revenue bonds.

The standalone credit profile (scp) is assessed at 'aa-'.

The Rating Outlook is Stable.

ANALYTICAL CONCLUSION

The downgrade to 'AA-' reflects Austin Electric's (AE) elevated leverage, which has steadily increased during the past three years. Weaker operating cash flows primarily driven by lower base rate revenues contribute to the utility's rising leverage, which was already somewhat high after AE's $460 million debt-financed purchase of Nacogdoches Power, LLC (NAC) biomass facility in fiscal 2019. Gains from excess market sales during the 2021 winter storm event - estimated at $100 million - are being returned to customers through a lower Power Supply Adjustment (PSA).

The Stable Outlook reflects AE's projected improvement in operating cash flows, which assumes the implementation of AE's proposed base rate increase in January 2023. The rate adjustment remains subject to city council approval, which AE anticipates will occur in October to November 2022. The planned rate increase is projected to contribute an additional $48 million in base rate revenues. AE expects additional base rate increases will be necessary to improve the utility's operating cash flows and leverage profile on a sustained basis.

The rating also reflects Fitch's view of the elevated operating risk for public power systems located within Electric Reliability Council of Texas (ERCOT) regional market. Operating risk for all Fitch-rated ERCOT-based electric utilities remain constrained to an 'a' operating risk assessment due to the ongoing ERCOT risks, including natural gas delivery concerns, counterparty risk and price volatility, all of which were exposed during the Texas winter storm event in February 2021. Costs related to AE's Resource Generation and Climate Protection Plan to 2030 (2030 Plan), which outlines the city's goal to have 100% carbon-free electric generation by 2035, are not expected to materially increase in the near term, but could increase over the longer term.

The rating also considers Austin's robust service area characteristics, including the utility's consistently strong customer growth rates, and the city of Austin's (general government IDR AA+/Stable) very strong economy.

CREDIT PROFILE

AE provides exclusive electric service to over 500,000 electric customers in and around the City of Austin. The city of Austin makes up roughly half of the utility's defined geographical service territory, while sizeable portions of Travis and Williamson Counties make up the balance. AE is the sole supplier of electric service in its service area with the exception of an 11 square mile area accounting for less than 5% of the utility's service territory. The single-certified territory is not subject to retail competition introduced in parts of Texas in 2000. Municipal utilities in the state have the option to offer retail competition in their service areas. AE has indicated no intent to do so.

Fitch considers the system to be a related entity to the city for rating purposes given the city's oversight of the system, including the authority to establish rates. The credit quality of the city does not currently constrain the bond rating. However, as a result of being a related entity, AE's ratings could become constrained by a material decline in the general credit quality of the city.

February 2021 Winter Storm Event

AE is the only Fitch-rated ERCOT public power issuer that experienced a net positive financial impact from the winter storm event, with net revenues approximating $100 million. Like many Texas utilities, AE experienced a surge in natural gas prices, prompted by unprecedented and prolonged below freezing temperatures across the state; however, AE benefited financially from energy sales from its generation fleet which more than offset the higher fuel costs and power purchased through ERCOT to serve system load. AE's generation fleet generally performed well, with limited outage times at its facilities during the winter storm event.

The positive financial impact from the storm are being returned directly to customers through rates. AE began returning a portion of the net proceeds from the winter storm to customers in fiscal 2022, partially offsetting AE's need to adjust the utility's PSA in light of the recent rise in the utility's power supply costs. AE has returned approximately $68 million (unaudited) through May 31, 2022 and expects to return any remaining storm-related revenues through FYE 2022, excluding any net receivables due from ERCOT (approximately $27 million) The timing and ultimate payment amount on the ERCOT receivable is expected to be determined following resolution of the Brazos Electric Power Cooperative (BEPC) bankruptcy. Management does not intend to return any additional funds related to the receivable until AE receives payment from ERCOT.

While the storm resulted in a positive financial impact for AE, AE remains exposed to meaningful operational risk in the ERCOT market. Approximately 40% of the utility's customer base remained without power for multiple days due to ERCOT-mandated load shedding events. Reduced customer load, in addition to AE's strong power supply performance through most of the winter event, allowed the utility's power generation to exceed customer usage and therefore, benefit from the excess market sales.

AE is required to transact energy purchases through ERCOT, which is regulated by the Public Utilities Commission of Texas (PUCT) and governed by deregulated market principles established by the Texas Legislature. Participation in ERCOT exposes parties to price volatility and counterparty risk, with the potential to share in counterparty default costs. These risks were realized during the February 2021 winter storm event and Fitch believes the operating risk of ERCOT-based public power systems remains elevated.

KEY RATING DRIVERS

Revenue Defensibility: 'aa'

Strong Customer Growth and Rate Affordability

AE's revenue defensibility is well supported by revenues from electric sales within and around the City of Austin and electric rates that are established locally by the city council. AE's revenue defensibility reflects rapid and sustained annual customer growth, which averaged 2.5% over the last five years. Service area characteristics, rate flexibility, and affordability are all very favorable.

Operating Risk: 'a'

Low Operating Costs; Weaker Operating Cost Flexibility

AE's operating risk profile remains strong reflecting the utility's low operating costs at 11.1 cent/KWh in fiscal 2021, but also considers Fitch's view of the elevated risks associated with operating in the ERCOT market. These risks became evident during the February 2021 winter storm event in the form of extreme price volatility and counterparty risks, both of which weaken Fitch's view of AE's operating cost flexibility.

AE continues to transition its power supply to more renewable resources, which accounted for 61% of AE's 2021 total energy load, up from 23% in fiscal 2015. Fitch expects the utility's operating costs to remain relatively stable in the near term even as owned resources continue to be replaced with renewable contracts over the next five years; however, increased reliance on ERCOT market purchases to supplement AE's power supply further exposes AE to market price volatility.

Financial Profile: 'aa'

Elevated Leverage, Proposed Rate Increases to Improve Cash Flow

AE's financial profile showed continued weakening in fiscal 2021 as the utility's operating revenues narrowed to a five-year historical low. Declines were primarily driven by the utility's lower base rate revenues, which are expected to remain at lower levels in fiscal 2022, offset by the recognition of a portion of the net revenues AE gained during the February 2021 winter storm event. Fitch expects the implementation of AE's planned base rate increase in January 2023 would significantly improve the utility's operating cash flows and return AE's leverage profile to levels commensurate with an 'aa' financial profile assessment. Long-term debt is expected to trend slightly higher over the next five years as the utility partially debt finances its capex plan, but should not materially impact the utility's leverage profile.

RATING SENSITIVITIES

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Improved operating cash flows resulting in projected leverage declines consistently below 7.0x in Fitch's base and stress case scenarios;

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--An inability to maintain leverage below 8.0x in Fitch's base and stress case scenarios;

--Unanticipated increases in AE's operating costs and/or capital expenditures as the utility transitions its power supply following the closure of the Decker Creek gas-fired Units 1 & 2 (Decker units);

--Inflationary cost pressures that weaken AE's financial profile on a sustained basis;

--Legislative or regulatory changes that impose material new operating or capital costs for utilities.

Best/Worst Case Rating Scenario

International scale credit ratings of Sovereigns, Public Finance and Infrastructure issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of three notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

SECURITY

Electric-system revenue bonds are secured by net revenues of AE. The bonds are on parity with the prior subordinate-lien obligations of the combined utility systems. The prior subordinate-lien obligations are secured by a joint and several pledge of net revenues of the combined utility systems, consisting of AE and Austin Water Utility (revenue bonds rated AA-/Stable). The prior subordinate-lien obligations are rated (AA-) on par with the electric system revenue bonds, given the small amount of debt outstanding in relation to AE's overall outstanding debt. The issuance of additional bonds secured by the combined utility pledge is no longer permitted by the master bond ordinance, making the lien effectively closed. The remaining prior subordinate lien bonds mature in 2025.

Revenue Defensibility

Revenue Source Characteristics

Fitch considers AE's revenue source characteristics as very strong reflecting the electric utility's monopolistic characteristics. Core electric revenues constitute nearly all of AE's pledged revenues to electric bondholders, but also include the utility's chilled water business which contributed approximately 2.2% ($28 million) of revenues during fiscal 2021.

The chilled water business is a fundamental component of the electric utility's strategy to reduce electric usage during peak hours in order to reduce overall costs. Chilled water plants use energy during off-hours to chill water that is used for air conditioning in commercial buildings in Austin's urban core. Companies participating in Austin's chilled water program have constructed their buildings to be cooled by AE's chilled water facilities and signed long-term contracts with the city for the service. AE's residential and commercial demand response programs are also integral to AE's plan to reduce peak demand.

Service Area Characteristics

The strength and diversity in both AE's customer base and Austin's economy continue to underpin electric demand, thereby contributing to the utility's revenue collections. Customer growth remains strong as evidenced by the utility's five-year CAGR of 2.5%. Energy sales growth, with a five-year CAGR of 0.3%, is tempered relative to the utility's customer growth rates reflecting energy efficiency gains, in addition to the utility's broader strategic investments to reduce peak demand. AE management conservatively estimates customer and annual load growth rates of 1.7% and 0.6%, respectively, over the next five years. Residential customers have accounted for approximately 40% of electric revenues in recent years.

The City of Austin continues to be one of the fastest growing U.S. metro-area economies. The city is the state capital and home to the University of Texas system's (AAA/Stable) flagship Austin campus, as well as six other colleges and universities. The state government and higher education sectors historically have provided stability and an economic cushion during downturns and the technology sector continues to stimulate economic growth within the service territory.

The city's population outpaces both the state and the nation, and is estimated at nearly 1 million residents. Wealth indicators for the area are above average with median household income at 114% of the national average. Much like the rest of the nation, Austin's unemployment rate peaked in the spring of 2020 (12.4% in April 2020), but rates have since dropped to 2.6% in March 2022, below the state and national March 2022 figures of 3.9% and 3.8%, respectively.

Rate Flexibility

AE's average residential retail revenue per kilowatt hour (10.6 cents/kWh) as reported by the U.S. Energy Information Administration in 2020 compares favorably to other large Texas utilities and the state average. Both AE rates and statewide revenue per kWh have benefited from lower natural gas and renewable energy costs. The low electric rates continue to contribute to AE' very affordable rates. AE's rate affordability also benefits from the City of Austin's high median income levels, as well as AE's lower average power consumption levels among its customer base, relative to other Texas utilities. Fitch measures rate affordability as the total cost of residential electric service divided by median household income within the service territory. AE's rate affordability was 1.4% in 2020.

Electric rates are approved by the city council and are not subject to any additional oversight, although the city hires an independent consumer advocate as part of the rate review process. AE conducts a cost-of-service study at least once every five years to determine its base rates which account for approximately half of AE's average residential retail bill. The majority of the remaining bill relate to energy (i.e., PSA), regulatory (transmission costs), and community benefit charges, each of which is reviewed at least annually and can be adjusted more frequently if needed.

Base Rate Review - Rate Increase Planned

Based on AE's cost of service study completed in April 2022, management is proposing to increase AE's customer charge to better recover the utility's fixed operating costs and improve revenue stability. Management anticipates the rate adjustment, in addition to the rate structure change, will increase base rate revenues by approximately 7.6%, contributing an additional $48 million in revenues.

The rate increase appears necessary to improve AE's revenue stability and operating margins; however, customer rate flexibility could be impacted. While the proposed base rate increase will result in a 7.6% increase in base rate revenues, actual bill impacts will vary depending on the customer class and energy consumption. Average residential customers (estimated at 900kWh/month) will see a 17% monthly bill increase, primarily due to the proposed increase in the customer charge. The estimated bill impacts exclude adjustments to energy charges, which could see upward pressure given the recent rise in commodity prices. Customer education efforts about the rate proposal are ongoing and management anticipates city council will vote on the proposed increase in October to November 2022 with a planned implementation in January 2023.

The current base rate review represents an interim review and follows AE's 2021 rate review, which resulted in base rates remaining unchanged. AE last adjusted its base rates following a 2016 rate review, in which base rates were reduced by 6.7% starting in January 2017. Future base rate reviews are expected to consider AE's potential exit from the Fayette coal facility, in addition to an expected decline in in certain PSA costs related to the NAC biomass facility.

The City of Austin's council maintains a stated 2% annual rate cap target. However, the 2% cap is evaluated over time, on average, so the recent years of lower fuel and purchased power costs have created headroom in AE's rates as compared with the 2% annual cap target put in place in 2012. Fitch does not view the 2% annual cap target to be a practical constraint on AE's rates.

Rate Structure Considerations

Fitch believes AE's annual electric rate adjustment mechanisms are essential for the full recovery of ongoing power costs. An additional and important cost recovery component is the recovery of line extension costs. AE made the decision to move to 100% recovery of costs in 2015. Fiscal 2016 was the first full year the policy was in place and cash collections have averaged $42 million annually during the five years through fiscal 2021. Connection fees are expected to continue to recover costs associated with AE's robust customer growth.

Operating Risk

Low Operating Costs, Transitioning Power Supply

AE's operating costs remained low at 11.1 cents per kWh in fiscal 2021. Total utility operating costs decreased in fiscal 2021 despite the increase in commodity costs related to the winter storm as total fiscal 2021 energy sales declined by approximately 1.7% from fiscal 2020. Rising fuel and market prices, in addition to other inflationary pressures, are likely to cause the operating costs to increase in fiscal 2022, but Fitch expects costs to moderate over the medium to long term as inflationary pressures ease. Additionally, AE's pursuit of its Resource Generation and Climate Protection Plan to 2030 (2030 Plan), which outlines the city's goal to have 100% carbon-free electric generation by 2035, is not expected to materially impact the utility's overall operating costs in the near-term, but could result in cost increases over the longer term.

AE owns 1,860MW generation capacity, excluding the 405MW gas-fired Decker Unit 2, which ceased operations on March 31, 2022. AE also purchases approximately 2,588MW of energy through purchase power contracts, all of which are sourced through renewable projects located within ERCOT. While AE's total capacity including purchased power appears larger than needed relative to AE's 2021 peak of 2,644MW, renewable generation is intermittent and only available during certain times.

Operating Cost Flexibility

AE's operating cost flexibility is assessed at weaker reflecting AE's exposure to ongoing risks associated with the ERCOT market operating structure and volatile commodity prices, both of which were evident during the February 2021 weather event. While AE did not suffer any negative financial impacts from the winter event, the utility remains exposed to structural weaknesses in the ERCOT market.

While the operating risk in ERCOT remains elevated, the Public Utility Commission of Texas and ERCOT market administrators have taken steps to limit future operational and financial risk to utilities. Additional winterization requirements and reduced market price caps - from $9,000/kWh to $5,000/kwh - are expected to have the most meaningful impact on overall market risk. Additionally, ERCOT administrators expects to maintain higher reserve margins the coming years as additional generation units come on line, which should provide additional resource adequacy. ERCOT's summer 2022 planning reserve margin increased to 23% from less than 10% during the 2019 summer.

Environmental Considerations and Clean Energy Transition

Approximately 87% of AE's annualized load was carbon-free during fiscal 2021, with renewable energy accounting for the largest portion of the fuel supply at nearly 61% of net load during fiscal 2021 and the remaining coming from the South Texas Project nuclear facility. However, coal generation, which had steadily declined as a percentage of AE's fuel supply from 30% in 2017 to 19% in fiscal 2020, increased to 25% in fiscal 2021. AE relied more heavily on its coal facility during the February 2021 winter event, which contributed to the overall increased coal power production in fiscal 2021. Excess load was sold through the ERCOT market through bilateral sales.

AE retired its Decker Unit 2 facility natural gas-fired facility, on March 31, 2022, in accordance with the 2030 Plan. However, AE's plan to retire its share of the Fayette coal-fired facility by the end of 2022 was postponed indefinitely after negotiations between AE and the other joint owner, the Lower Colorado River Authority (LCRA; AA-/Stable), stalled in late 2021. AE intends to minimize the facility's scheduled output while it continues to run its portion of the facility, but neither AE nor LCRA has committed to a future Fayette retirement date. The impact on AE's carbon-free generation targets remains uncertain; however, the facility provides a physical hedge to rising natural gas prices and market price volatility over the near to medium term. AE's financial forecast assumes the plant remains in service through at least the next five years.

AE anticipates layering in renewable resources following the planned retirement of the utility's thermal generation resources. Intermittency of renewable power poses some additional ERCOT price risks, however, as AE would likely need to purchase power during periods of weaker renewable generation.

AE's robust energy risk program focused on entering into futures contracts, options and swaps, somewhat mitigates the financial exposure of short-term price volatility. AE does not anticipate having large open positions after the planned closure of its thermal resources.

Fitch does not expect AE's 2030 plan will meaningfully affect operating costs over the medium term. The utility is generally well positioned to meet the goals included in the plan. The goals of the 2030 Plan are subject to certain overarching affordability goals including the 2% rate cap target, which places a protective limit on the overall cost and pace of AE's resource conversion.

Capital Planning and Management

Fitch calculates AE's age of plant at 15 years, which potentially reflects elevated capital needs. Fitch expects the average of age of plant could decline as AE expects to retire older generation plants in the near term. Capex to depreciation, which averaged just over 100% during fiscals 2015-2018, increased substantially in fiscal 2019 due to the purchase of the NAC biomass facility, but returned to historical levels at 106% in fiscal 2021. AE plans to accelerate the depreciation of the NAC facility through December 2022.

AE's five-year capital improvement program (CIP; fiscals 2022-2026) includes an estimated $1.2 billion in planned investments. The CIP includes additional spending for distribution and transmission projects that will be needed to support the planned closure of the Decker unit 2, facilitate additional purchase power imports into the city, and support the Austin service territory growth. Transmission costs will be recovered through the ERCOT transmission rate that is charged proportionally across all electric customers within ERCOT.

Financial Profile

AE's financial profile weakened in fiscal 2021, with leverage rising to 11.1x and coverage of full obligations declining below 1.0x. Rising debt levels to fund capex, including approximately $88 million for the construction of a new headquarters complex, contributed to the utility's elevated leverage in fiscal 2021. AE's leverage was also impacted by the utility's weaker operating cash flows in fiscal 2021, which declined primarily due to lower base rate revenues.

AE's leverage, which was 5.8x in fiscal 2018, has steadily increased during the past three years due to a combination of increased debt and weakened operating cash flows. AE's debt-financed purchase of the NAC biomass plant for approximately $460 million in June 2019 increased AE's long-term debt burden to $2.0 billion at FYE 2019 from $1.5 billion at FYE 2018. Weaker than projected operating cash flows in fiscals 2020 and 2021 have also contributed to the utility's rising leverage. Fiscal 2020 operating revenues declined following City Council's April 2020 approval to reduce rates in response to the economic impacts from the pandemic. Coverage levels, which were also impacted by increased debt service related to the NAC biomass facility, declined in fiscal 2020, with Fitch-calculated DSC dropping to 1.8x from 3.4x in fiscal 2019. The utility also provided electric bill relief customers during fiscals 2020 and 2021 of $35 million and $5 million, respectively.

AE's very healthy cash and reserve balances have somewhat tempered the rise in the utility's leverage metrics. However, AE's liquidity metrics have declined over the past 18 months as the utility used its cash reserves to supplement the reduction in operating cash flows. Unrestricted cash balances, which were $690 million at FYE 2020, declined to $618 million at FYE 2021 and were approximately $558 million as of Jan. 31, 2022 (unaudited). AE's financial policies include a combined reserve target amount equal to no less than 150 days of operating and maintenance expenditures. Fitch calculated AE's days cash on hand at FYE 2021 at approximately 217 days. AE's proposed, but not yet approved, base rate increases are expected to steadily increase the utility's unrestricted cash balances.

Fitch Analytical Stress Test (FAST) - Base Case and Stress Case

The FAST base case scenario represents Fitch's expectation of AE's financial performance through the five-year forecast period ending in fiscal 2026. The scenario analysis considers AE's planned base rate increases, rate adjustment mechanisms, including the power supply adjustment, and regulatory and community benefit charges, will continue to pass through costs to retail consumers.

Fitch expects fiscal 2022 retail electric revenue will increase substantially as AE passes through rising power supply costs. However, excluding the benefit from the extraordinary winter storm revenues, operating cash flows are expected to remain weaker and contribute to AE's elevated leverage in fiscal 2022, which is expected to remain near 10x at FYE 2022.

The FAST base and stress scenarios assume AE's proposed base rate increase is approved by City Council during the fall of 2022 and implemented in January 2023 (fiscal 2023). The improved operating cash flows in fiscal 2023 are expected to drive AE's leverage lower, remaining between 7.0x and 7.5x through fiscal 2024. However, lower than projected operating cash flows, which would likely occur if AE's proposed base rate increases are not approved, would pressure Fitch's assessment of AE's leverage profile. Unanticipated capex that result in a substantial decline in cash reserves, or an increase in debt, would also pressure AE's leverage profile. Unrestricted cash levels are expected to increase over the next five years, but days cash on hand should remain around 200 days as the utility's liquidity is somewhat offset by rising operating expenses.

Fitch's stress case anticipates a decline in sales in the first two years with a recovery in the final three years of the forecast. The stress case assumes a 5.2% decrease in year one followed by another 2.6% decrease in year two, both of which would be sizable declines for AE given the utility's historical customer growth; however, Fitch believes the stress is reasonable given some volatility in AE's historical energy sales. The declines are layered on AE's conservative annual load growth assumption of 0.6%.

AE's rate adjustment mechanisms could be implemented to mitigate a substantial decline in energy sales or operating cash flow. However, the approval of additional incremental rate increases could prove more challenging following the implementation of the proposed base rate increase in January 2023, a risk that is somewhat heightened given AE's pass through of the higher energy and fuel prices in fiscal 2022. Fitch believes AE would likely increase rates to offset the rising costs, but leverage would remain elevated over the near to medium term in a stressed scenario.

AE maintains a $27 million net cash receivable from ERCOT resulting from the 2021 winter storm. The ultimate payment primarily depends on the resolution of the BEPC bankruptcy. Fitch did not include these revenues in the scenario analysis.

Debt Profile

Outstanding debt, including AE's portion of the very small amount of remaining combined subordinate lien obligations, totals approximately $2.1 billion, all of which was issued as fixed-rate obligations. The combined subordinate lien obligations mature in 2025. AE uses its tax-exempt and taxable commercial paper programs to fund construction, which is periodically refinanced with long-term debt. Fitch's leverage calculation included an additional $904 million of other obligations including pension liabilities and capitalized fixed charges for purchased power.

In addition to the sources of information identified in Fitch's applicable criteria specified below, this action was informed by information from Lumesis.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG Considerations

AE has an ESG Relevance Score of '4' for Exposure to Environmental Impacts due to the effects of the February 2021 severe winter weather event, which weakens the operating flexibility assessment. The weather event exposed deficiencies in ERCOT's market design and ability to keep the grid functioning well in the face of an extreme weather event, which exposes AE to price volatility and counterparty risk outside of its control, which has a negative impact on the credit profile, and is relevant to the ratings in conjunction with other factors.

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Fitch Ratings Analysts

Tim Morilla
Director
Primary Rating Analyst
+1 512 813 5702
Fitch Ratings, Inc. 2600 Via Fortuna, Suite 330 Austin, TX 78746

Kathy Masterson
Senior Director
Secondary Rating Analyst
+1 512 215 3730

Major Parkhurst
Director
Committee Chairperson
+1 512 215 3724

Media Contacts

Sandro Scenga
New York
+1 212 908 0278
sandro.scenga@thefitchgroup.com

Rating Actions

ENTITY/DEBT	RATING			RECOVERY	PRIOR
Austin (TX) [Electric]					
• Austin (TX) /Combined Utility Revenues - Subordinate/ 1 LT	LT	AA-	Downgrade		AA

ENTITY/DEBT		RATING		RECOVERY	PRIOR
• Austin (TX) /Electric System Revenues/ 1 LT	LT	AA- ⭘	Downgrade		AA ⊖

RATINGS KEY	OUTLOOK	WATCH
POSITIVE	⊕	⬘
NEGATIVE	⊖	⬙
EVOLVING	⭘	◆
STABLE	⭘	

Applicable Criteria

Public Sector, Revenue-Supported Entities Rating Criteria (pub.01 Sep 2021) (including rating assumption sensitivity)

U.S. Public Power Rating Criteria (pub.09 Apr 2021) (including rating assumption sensitivity)

Applicable Models

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

FAST Econometric API - Fitch Analytical Stress Test Model, v3.0.0 (1)

Additional Disclosures

Solicitation Status

Endorsement Status

Austin (TX)	EU Endorsed, UK Endorsed

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Exhibit MD-4 2WR RFI 3-7

Austin Energy's Response to 2WR's Third RFI

2WR 3-7: In response to 2WR TC 2-2 you stated that $43.6 million in CIAC is included in the rate-filing package to reduce the revenue by offsetting internally generated funds for construction. Please provide 2WR the underlying workpapers and calculations to the $43.6 million dollar amount along with the supporting documentation including how the CIAC was accounted for in AE's books and records.

ANSWER: See WP C-3.3.1 of the Base Rate Filing Package. The $43.6 million in CIAC is calculated in Excel column H and represents the three-year average of FY 2019, FY 2020, and FY 2021 amounts. CIAC is recorded as Capital Contributions on the income statement when received. It is then deferred in the non-operating section of the income statement and amortized over the average useful life of assets being depreciated.

Prepared by: GR / MG

Sponsored by: Grant Rabon

Exhibit MD-5 Austin Energy response TIEC RFI 3-3

Austin Energy's Response to TIEC's Third RFI

TIEC 3-3: Confirm that Austin Energy would achieve a 2.7 times Debt Service Coverage ratio under the proposed rates. If not confirmed, quantify the Debt Service Coverage ratio under the proposed rates.

ANSWER: Not confirmed. Austin Energy estimates the debt service coverage resulting from the proposed base rates will be approximately 2.35 times (as approximated in the table below) based on the information contained in the Base Rate Filing Package.

Note: There can be nuanced differences in the components used in the calculation of debt service coverage depending on who is performing the calculation (e.g., credit rating agencies, Austin Energy, etc.) and the intended purpose of the calculation (e.g., GAAP financials, debt covenant or financial policy compliance, etc.).

Base Revenues (proposed base rates)	$ 691,986,641
Pass-Through Revenues	506,296,114
Other (net of bad debt)	172,601,937
Total	$ 1,370,884,691
Operating Expenses (excluding depreciation)	$ 997,736,055
Funds Available for Debt Service	$ 373,148,637
Debt Service	$ 158,458,228
Debt Service Coverage Ratio	**2.35**

Prepared by: GR

Sponsored by: Grant Rabon

PF2-033

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PARTICIPATION AGREEMENT

BETWEEN

THE CITY OF AUSTIN

&

LOWER COLORADO RIVER AUTHORITY

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THE FAYETTE POWER PROJECT

PARTICIPATION AGREEMENT

1. PARTIES: The parties to this agreement are: CITY OF AUSTIN, hereinafter referred to as "Austin," and LOWER COLORADO RIVER AUTHORITY, hereinafter referred to as "LCRA."

2. RECITALS: The parties, having completed a feasibility study, desire to enter into this Participation Agreement providing for the construction, operation and maintenance of jointly owned and operated electric generation facilities to be known as the Fayette Power Project, hereinafter referred to as the Project.

3. AGREEMENT: In consideration of the mutual covenants herein, the parties agree as follows:

4. DEFINITIONS: The following terms, when used herein, shall have the meanings specified:

4.1 ADDITIONAL GENERATING UNIT: The second or any subsequent Generating Unit to be located on the Plant Site.

4.2 CAPACITY: Electrical rating expressed in megawatts (mw) or megavolt-amperes (mva) and based on manufacturer's nameplate electrical ratings where available.

4.3 CAPITAL ADDITIONS: Any Units of Property, land or interests in land which are added to the Project and which are not in substitution for any existing Units of Property, land or interests in land constituting a part of the Project, and which in accordance with accounting practice should be capitalized.

4.4 CAPITAL BETTERMENTS: Any improvements to the Project, including any enlargement or improvement of any Units of Property constituting a part of the Project or the substitution therefor, where such substitution constitutes an enlargement or improvement as compared with that for which it is substituted, and which in accordance with accounting practice should be capitalized.

4.5 CAPITAL IMPROVEMENTS: All or any Capital Additions, Capital Betterments, or Capital Replacements.

4.6 CAPITAL REPLACEMENTS: The substitution of any Units of Property for other Units of Property constituting a part of the Project, where such substitution does not constitute an enlargement or improvement of that for which it is substituted, and which in accordance with accounting practice should be capitalized.

4.7 COMMON STATION FACILITIES: Those components of the Project identified in Exhibit A as being for the common use of the initial Generating Unit and for the common use of any Additional Generating Units hereafter comprising the Project.

4.8 CONSTRUCTION WORK: All environmental impact studies, site evaluation, acquisition of the Plant Site, Engineering, design, construction, contract preparation, supervision, expediting, inspection, accounting, testing and start-up for Generating Units and Common Station Facilities up to the time of Firm Operation and the decommissioning, dismantling, removal and final disposition of all components of the Project, including, but not by way of limitation, all related engineering, design, contract preparation, purchasing, supervision, expediting, inspection, accounting, testing, management and protection.

4.9 CONSTRUCTION WORK LIABILITY: Liability of a Participant for damage suffered by anyone other than a Participant which arises out of Construction Work and is not discharged by Project Insurance, and is not the result of Willful Action.

4.10 ENERGY: Kilowatt-hours (kwh).

4.11 FIRM OPERATION: The state of completion at which a Generating Unit of the Project is determined by the Management Committee to be reliable and at which such unit can reasonably be expected to operate continuously at its rated Capacity.

4.12 FPC ACCOUNTS: The accounts prescribed by the Federal Power Commission's "Uniform System of Accounts Prescribed for Public Utilities and Licensees (Class A and Class B)" in effect as of July 1, 1974, as such system of accounts may be amended from time to time as maintained in accordance with generally accepted accounting principles.

4.13 GENERATION ENTITLEMENT SHARE: The percentage entitlement of each Participant in a particular Generating Unit of the Project. Each Participant's percentage entitlement shall be equal to such Participant's percentage owner-ship in the particular unit at the applicable time as contemplated by this Participation Agreement.

4.14 GENERATING UNIT: An electric generating unit, including the components thereof (steam supply system, turbine and generator including step-up transformers and other associated equipment), located on the Plant Site. A Generating Unit does not include Common Station Facilities but does include that portion of the Plant Site allocated thereto in Exhibit B hereto, and in the case of an Additional Generating Unit, that portion selected by the Participant proposing the Additional Generating Unit and approved by the Management Committee.

4.15 MANAGEMENT COMMITTEE: The committee composed of representatives of each Participant established pursuant to Section 9.1 hereof.

4.16 MINIMUM NET GENERATION: The lowest net Power output at which each Generating Unit can be reliably maintained in service on a continuous basis.

4.17 NET EFFECTIVE GENERATING CAPABILITY: The maximum continuous ability of each Generating Unit to produce power which is available to the Participants at the high voltage terminals of the generator step-up transformers.

4.18 NET ENERGY GENERATION: The Energy generated by a Generating Unit which is available to the Participants at the high voltage terminals of the generator step-up transformers less the portions of station service requirements attributable to such Unit.

4.19 PARTICIPANT: A party hereto or other entity acquiring an interest in the Project in accordance with this Participation Agreement.

4.20 PLANT OWNERSHIP INTEREST: The percentage interest of the participants in the Project. Each Participant's percentage interest shall be equal to such Participant's ownership in the Common Station Facilities at the applicable time as contemplated by this Participation Agreement.

4.21 POWER: Kilowatts (kw) or megawatts (mw).

4.22 PROJECT AGREEMENTS: This Participation Agreement, any construction agreements, agreements for fuel and water supply and such other agreements relating to the Project, as the Participants find necessary or desirable to designate as

Project Agreements, as each of such agreements is originally executed or as any of same may thereafter be supplemented or amended.

4.23 PROJECT INSURANCE: Policies of insurance to be procured and maintained in accordance with Section 25 hereof.

4.24 PROJECT MANAGER: The Participant responsible for the planning, construction and operation of the Project in accordance with this Participation Agreement and the Project Agreements.

4.25 PLANT SITE: A parcel of land in Fayette County, Texas, consisting of approximately 6,400 acres and being generally depicted on Exhibit B hereto.

4.26 PROJECT: The Plant Site and, as initially contemplated, one coal or lignite fueled steam electric generating unit, having a Capacity of approximately 600 mw and all facilities and structures used therewith or related thereto and to be constructed on or adjacent to the Plant Site. The Project is generally described in Exhibit A hereto. Said definition shall also include any Additional Generating Unit located on the Plant Site pursuant to this

Participation Agreement or any of the Project Agreements and all facilities and structures used therewith or related thereto and constructed on or adjacent to the Plant Site.

4.27 STATION WORK: Operation, maintenance, use or repair of the Project subsequent to the time of Firm Operation, including, though not by limitation, all related engineering, contract preparation, purchasing, supervision, expediting, inspection, accounting, testing, management and protection.

4.28 STATION WORK LIABILITY: Liability of one or more Participants for damage suffered by anyone other than a Participant which arises out of Station Work, and is not discharged by Project Insurance, and is not the result of Willful Action.

4.29 UNIT 1: The initial Generating Unit contemplated for the Project.

4.30 UNITS OF PROPERTY: Units of property as described in the Federal Power Commission's "List of Units of Property for Use in Connection with Uniform System of Accounts prescribed for Public Utilities and Licensees" in effect from time to time.

4.31 WILLFUL ACTION:

4.31.1 Action taken or not taken by a Participant at the direction of its governing body or board, which action is knowingly or intentionally taken or not taken with intent to cause injury or damage to another.

4.31.2 Action taken or not taken by an employee of a Participant, which action is intentionally taken or not taken with intent to cause injury or damage to another and which action or non-action is subsequently ratified by the Participant employing such employee at the direction of its said governing body or board.

4.31.3 Willful Action does not include intentional acts or omissions of a Participant for which a Participant is legally responsible solely because of the master-servant relationship between such Participant and its employees.

5. <u>OWNERSHIP OF PROJECT</u>:

5.1 Each Participant shall acquire and, subject to adjustments as provided herein, shall initially own an undivided fifty percent (50%) interest in the Plant Site, the Common Station Facilities and Unit 1 as a tenant in common with the other Participant.

6. <u>ADDITION OF GENERATING UNITS</u>:

6.1 A Participant may propose the construction of an Additional Generating Unit by written notice to the other Participant setting forth:

6.1.1 A general description of the proposed Additional Generating Unit and of proposed Capital Additions and Capital Betterments to the existing Common Station Facilities, all in the same form and detail as Generating Unit 1 is shown in Exhibit A hereto, identifying all Common Station Facilities proposed for use in connection with the proposed Additional Generating Unit or with respect to which Capital Additions or Capital Betterments are proposed.

6.1.2 A plat of the Plant Site depicting the location of the proposed Additional Generating Unit.

6.1.3 An estimate of the respective costs of the proposed Additional Generating Unit, Capital Additions and Capital Betterments, all in reasonable detail.

6.2 Within forty-five (45) days after service of the written notice given pursuant to Section 6.1 hereof, the Project Manager shall furnish to each Participant a statement, in reasonable detail, of all actual costs (without depreciation) of all Construction Work attributable to the Common Station Facilities identified in Section 6.1.1 hereof, as shown on the books of such Project Manager.

6.3 The non-proposing Participant may elect to participate in the proposed Additional Generating Unit, Capital Additions and Capital Betterments to the extent of its Plant Ownership Interest by written election served upon the proposing Participant within three (3) months after service of the written notice given pursuant to Section 6.1 hereof. Failure of a Participant to exercise said election as provided in this Section 6.3 within the time period specified shall be conclusively deemed to be an election not to participate.

6.4 Should the non-proposing Participant elect to participate in the proposed Additional Generating Unit, the proposed Additional Generating Unit, Capital Additions and Capital Betterments shall be constructed, operated and maintained in accordance with the provisions of this Participation Agreement and the Project Agreements, shall be owned (subject to adjustments as provided herein) by the Participants in proportion to their Plant Ownership Interests, and shall become a part of the Project.

6.5 Should the non-proposing Participant elect not to participate in the proposed Additional Generating Unit, the proposing Participant shall construct, and the Project Manager shall operate and maintain the Additional Generating Unit, Capital Additions and Capital Betterments proposed pursuant to Section 6.1 hereof on the following basis:

6.5.1 The Additional Generating Unit shall be owned by the proposing Participant.

6.5.2 Within two (2) months after the proposing Participant has determined the actual costs of the Capital Additions and Capital Betterments to the previously existing Common Station Facilities undertaken in conjunction with the Additional Generating Unit, the Project Manager shall furnish to each Participant a statement, supplemental to the statement furnished pursuant to Section 6.2 hereof, setting forth the costs shown in the statement furnished pursuant to Section 6.2 hereof and the actual costs of said Capital Additions and Capital Betterments. Within one (1) month after receiving the statement called for in this Section 6.5.2, the Participant owning the Additional Generating Unit shall make a cash payment to the other Participant equal to the amount, if any, by which: (i) the product of the total costs shown in the statement called for in this Section 6.5.2 times a fraction, the numerator of which is the nameplate rating of the Additional Generating Unit and the denominator of which is the sum of the nameplate ratings of all Generating Units including those agreed upon, under construction, completed and the Additional Generating Unit; exceeds (ii) the actual costs of said Capital Additions and Capital Betterments. Thereafter, the Plant Site (exclusive of the portions thereof allocated to all Generating Units theretofore agreed upon or permitted under this Participation Agreement or any of the Project Agreements or allocated to the Additional Generating Unit) and the Common Station Facilities shall be owned by the Participants, as tenants in common, in the proportion that the sum of the interests of each Participant in all Generating Units (including the Additional Generating Unit) bears to the sum of the interests of both Participants in all Generating Units (including the Additional Generating Unit) and appropriate transfers of interests shall be made.

6.5.3 The Participant proposing the Additional Generating Unit and the Capital Additions and Capital Betterments to existing Common Station Facilities shall provide as needed the construction costs of the Additional Generating Unit and of said Capital Additions and Capital Betterments and the operation and maintenance costs of the Additional Generating Unit. The operation and maintenance costs of the Common Station Facilities to which said Capital Additions and Capital Betterments relate shall be shared and paid by the Participants in proportion to their adjusted Plant Ownership Interest resulting from the Additional Generating Unit.

7. GENERATING CAPACITY AND ENERGY ENTITLEMENTS:

7.1 The Capacity entitlement of each Participant in each Generating Unit of the Project shall be the product of its Generation Entitlement Share in such Generating Unit and the Net Effective Generating Capability of such Generating Unit.

7.2 Each Participant shall be entitled to schedule for its account Power and Energy from any Generating Unit up to the amount of its available Capacity entitlement in such Generating Unit.

7.3 When a Participant requests operation of a Generating Unit, each Participant shall, unless otherwise mutually agreed, schedule for its account its share of Minimum Net Generation which shall be the product of its Generation Entitlement Share in said Generating Unit and the Minimum Net Generation established for such Generating Unit. At any time a Participant has scheduled from any Generating Unit an amount of Power in excess of its share of Minimum Net Generation, then the other Participant shall only be obligated to schedule for its account an amount of Power equal to the product of its Generation Entitlement Share and the remaining amount of Minimum Net Generation established for such Generating Unit provided that such reductions do not result in economic detriment to any Participant.

7.4 Operation of any Generating Unit by the Project Manager shall be subject to scheduled outages or curtailments, operating emergencies and unscheduled outages or curtailments of such Generating Unit.

8. <u>DELIVERY AND TRANSMISSION</u>:

8.1 Power and Energy shall be metered and delivered to the transmission systems of the Participants at the Project switchyard and shall be accounted for in accordance with the scheduling of the respective Participants.

8.2 Each Participant shall design, construct, own, operate and maintain the transmission facilities necessary to connect its system to the high voltage bus in the Project switchyard, with the objective of permitting each Participant to transmit under normal operating conditions its Generation Entitlement Share from units of the Project to its system in a manner which will not unreasonably affect the operation of the electric system of the other Participant or the interconnected systems of others.

8.3 Each Participant shall be entitled to the exclusive use of so much of the Plant Site as may be necessary to construct and connect its transmission facilities to the high voltage bus in the Project switchyard as generally shown in Exhibit A hereto, provided the actual location and construction schedule of such transmission facilities shall be subject to approval of the Management Committee.

9. <u>ADMINISTRATION</u>:

9.1 As a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis among the Participants in connection with various administrative and technical problems which may arise from time to time in connection with the terms and conditions of this Participation Agreement or the Project Agreements, the Participants hereby establish the Management Committee.

9.2 The Management Committee shall be composed of two representatives of each Participant and one alternate for each such representative who shall be designated by the Participant represented by written notice to the other Participant.

9.3 The Management Committee shall:

9.3.1 Provide liaison among the Participants at the management level and between them and the Project Manager;

9.3.2 Exercise general supervision over the Committees established pursuant to Section 9.8 hereof;

9.3.3 Consider and act upon matters referred to it by the committees established pursuant to Section 9.8 hereof;

9.3.4 Perform such other functions and duties as may be assigned to it in this Participation Agreement or in the Project Agreements;

9.3.5 Review, discuss and act upon disputes among the Participants arising under this Participation Agreement or the Project Agreements;

9.3.6 Review and act upon the Project Manager's recommendations concerning:

9.3.6.1 Bids and proposals for water supply, water rights and fuel other than coal and the furnishing of engineering services and studies, bids and proposals from vendors for the purchase and procurement of the equipment, apparatus, machinery, materials and supplies and bids and proposals from contractors for the performance and completion of Construction and Station Work if the obligation to be incurred exceeds the sum of $15,000;

9.3.6.2 The Project Insurance to be procured and maintained, including insurance values, limits, deductibles, retentions and other special terms;

9.3.6.3 The annual capital expenditures budget, annual manpower table and budget, and annual operation and maintenance budget, including guidelines for the utilization of Project Manager's employees;

9.3.6.4 The planned outages, schedules for maintenance and the manner of selection of any maintenance contractor for contract maintenance included in the annual operation and maintenance budget;

9.3.6.5 The policies for establishing the inventories for spare parts, materials and supplies;

9.3.6.6 The written statistical and administrative reports, written budgets, and information and other similar records, and the form thereof, to be kept by the Project Manager (excluding accounting records used internally by the Project Manager for the purpose of accumulating financial and statistical data, such as books of original entry, ledgers, work papers, and source documents);

9.3.6.7 The procedures for determining Net Effective Generating Capability, Minimum Net Generation and other Capacities of each Generating Unit and several Generating Units;

9.3.6.8 The procedures for determining capital expenditures;

9.3.6.9 The procedures for performance and efficiency testing;

9.3.6.10 The procedures for maintaining complete and accurate fuel, Power and Energy accounting;

9.3.6.11 The written statement of operating practices and procedures;

9.3.6.12 The list of transportation and motorized equipment to be owned or leased by the Project Manager for Station Work;

9.3.6.13 The establishment of practices and procedures for keeping each Participant advised of the Net Effective Generating Capability and for the delivery of Power and Energy from the Project in accordance with the Participants' schedule (such practices and procedures to provide for modifying said schedules to meet the needs of day-to-day or hour-by-hour operation, including emergencies on a Participant's system);

9.3.6.14 The establishment of procedures for the operation of the Project during periods of curtailed operations which reduce or may reduce the Net Effective Generating Capability;

9.3.6.15 The establishment of criteria for determination of date of Firm Operation;

9.3.7 Either Participant through its representatives on the Management Committee may request a recommendation or report from the Project Manager on any matter relating to the Project. Such recommendation or report shall be furnished within a reasonable time;

9.3.8 Arrange for annual audits of the records maintained by the Project Manager in its performance of Construction Work and Station Work and other company records maintained by the Project Manager in support of its billings to the Participants; and

9.3.9 Arrange for certification by a nationally recognized firm of Independent Certified Public Accountants to the Participants that the Project Manager's accounting methods and records, including any allocations for Construction Work and Station Work, as the case may be, are in accordance with this Participation Agreement, the Project Agreements and sound accounting practice.

9.4 All matters coming under the authority of the Management Committee shall be decided by majority vote of the members of the Committee with each member having equal voting rights. All decisions reached by the Management

Committee on matters concerning the Project and properly before the Management Committee for decision pursuant to the terms of this Participation Agreement or the Project Agreements shall be binding upon all Participants.

9.5 The Management Committee shall designate one of its members as Chairman and another as Vice Chairman, and shall appoint a Secretary and an Assistant Secretary, neither of whom need be a member of the Management Committee, and the Committee shall keep such minutes of its meetings as the Committee shall determine, provided a written record shall be made by the Committee of all of its actions and decisions.

9.6 Neither the Management Committee nor any of its appointed committees shall have any authority to modify any of the terms, covenants or conditions of this Participation Agreement or of the Project Agreements.

9.7 Each Participant shall give prompt written notice to the other Participant of any change in the designation of its representatives on the Management Committee. Any representative appearing at a committee meeting shall be deemed to have authority to act on behalf of the Participant he represents unless the Participant represented has designated another representative as provided in Section 9.2 hereof.

9.8 The Management Committee shall have the right to establish temporary or permanent committees. The authority and duties of any such committee shall be set forth in writing and shall be subject to the provisions of this Participation Agreement and the Project Agreements.

10. PROJECT MANAGER:

10.1 The Project Manager for the Project shall be LCRA.

10.2 Austin hereby appoints the Project Manager as its agent and the Project Manager shall undertake as Austin's agent and as principal on its own behalf the responsibility for the performance and completion of Construction Work and Station Work required by this Participation Agreement.

10.3 Subject to this Participation Agreement, the Project Manager shall:

10.3.1 Provide for and obtain all studies (including environmental impact studies and preliminary safety analyses), permits and licenses necessary for the construction and operation of the Project.

10.3.2 Acquire the Plant Site in accordance with the parameters set forth in Section 31 hereof, such acquisition to be for the initial benefit, and at the cost, of the Participants in the proportions set forth in Section 5.1.

10.3.3 Supply the Participants with copies of all studies made, license and permit applications filed and licenses and permits obtained.

10.3.4 Obtain bids and negotiate proposals for the furnishing of engineering services and studies necessary for the performance and completion of Construction Work.

10.3.5 Obtain bids and negotiate proposals from vendors for the purchase and procurement of the equipment, apparatus, machinery, materials. tools and supplies necessary for the performance and completion of Construction Work.

10.3.6 Obtain bids and negotiate proposals from contractors for the performance and completion of each component of Construction Work.

10.3.7 Review with the Management Committee all bids and proposals obtained under 10.3.4, 10.3.5, and 10.3.6 above and execute such contracts and accept bids and proposals as authorized by the Management Committee in the name of the Project Manager, acting as principal on its own behalf and as agent for Austin, except that Project Manager is authorized to execute contracts and accept bids involving expenditures of less than $15,000 without authorization of the Management Committee, subject to all legal requirements in respect to competitive bidding.

10.3.8 Transmit as received from consultants, contractors or vendors all correspondence, studies, specifications and drawings related to the Project to the Management Committee for review and comment.

10.3.9 Furnish Participants with duplicate original copies of all contracts with the contractors, subcontractors and vendors.

10.3.10 Arrange for the placement of Project Insurance pursuant to Section 25 hereof.

10.3.11 Determine what contractors, if any, shall be required to furnish any portion of Construction Insurance, other insurance and faithful performance and payment bonds.

10.3.12 Investigate, adjust, and settle claims arising out of or attributable to Construction Work or Station Work, the past or future performance or nonperformance of the obligations and duties of either Participant (including the Project Manager) under or pursuant to this Participation Agreement, or the past or future performance or nonperformance of Construction Work and Station Work, including but not limited to any claim resulting from death or injury to persons or damage to property for which payment shall not be made on account of valid and collectible Project Insurance or other valid and collectible insurance carried by either Participant, and present and prosecute claims against any insurer or other party for losses and damages in connection with Construction Work or Station Work. The terms of this Section 10.3.12 shall not include claims involving Willful Action by the Project Manager. The authorization from the Management Committee shall be obtained by the Project Manager before any claim or combination of claims arising out of the same transaction or incident is settled for more than One Hundred Thousand Dollars ($100,000.00), or the amount of any Project Insurance deductible, whichever may be greater.

10.3.13 Assist any insurer in the investigation, adjustment and settlement of any loss or claim.

10.3.14 Administer and enforce contracts in the name of the Project Manager, acting as principal on its own behalf and as agent for Austin.

10.3.15 Comply with (i) any and all laws and regulations applicable to the performance of Construction Work or Station Work, and (ii) the terms and conditions of any contract relating to Construction Work or Station Work.

10.3.16 Expend the funds advanced to the Project Manager in accordance with the terms and conditions of this Participation Agreement.

10.3.17 Keep and maintain records of monies received and expended, obligations incurred, credits accrued, estimates of Construction Costs (excluding ad valorem taxes and interest during construction) and contracts entered into in the performance of Construction Work, and make such records available for inspection by the other Participant at reasonable times and places.

10.3.18 Not suffer any liens in connection with Construction Work or Station Work to remain in effect unsatisfied against the Project (other than liens permitted under the Project Agreements, liens for taxes and assessments not yet delinquent, liens for workmen's compensation awards, and liens for labor and material not yet perfected); provided, however, that the Project Manager shall not be required to pay or discharge any such lien as long as the Project Manager in good faith shall be contesting the same which shall operate during the pendency thereof to prevent the collection or enforcement of such lien so contested.

10.3.19 As soon as practicable after the Date of Firm Operation of Unit 1, provide each Participant with a summary of the estimated construction costs applicable to such unit and the common facilities in a form which will allow each such Participant to classify such Construction Costs to appropriate accounts and by Units of Property.

10.3.20 Provide each Participant with all necessary and required records and information pertaining to the performance of Construction Work, including a monthly progress report.

10.3.21 Keep each Participant fully and promptly informed of any known default under the provisions of this Participation Agreement.

10.3.22 As soon as practicable after the commencement of Construction Work, furnish each Participant with a detailed forecast of total Construction Costs. Said forecast shall be revised and furnished to each Participant every three (3) months thereafter until completion of Construction Work, provided, that any significant changes in said forecast shall be submitted to each Participant as soon as practicable after such changes become evident. In addition, and as soon as practicable after commencement of Construction Work, furnish each Participant a detailed monthly forecast of each Participant's estimated expenditures for the succeeding month for Construction Work, which said forecast shall be furnished each Participant monthly thereafter until completion of Construction Work.

10.3.23 Furnish each Participant any information reasonably available pertaining to Construction Work that will assist said Participant in responding to a request for such information by any federal, state or local authority.

10.3.24 Use its best efforts in the performance of its responsibilities hereunder to effect the completion of Construction Work in accordance with the scheduled Date of Firm Operation.

10.3.25 Keep each Participant fully and promptly advised of the major developments in connection with the performance and completion of Construction Work.

10.3.26 Prepare and distribute the Final Completion Report to each Participant within eighteen months after the date of Firm Operation of Unit 1.

10.3.27 Conduct tests to verify that specified characteristics of equipment items have been achieved and, if necessary, make or arrange for final equipment modifications to meet the specified requirements thereof.

10.3.28 Obtain and enforce any and all customary warranties on equipment, facilities, and materials furnished for the Project.

10.3.29 Perform the Station Work in accordance with generally accepted practices in the electric utility industry as such practices may be affected by the design and operational characteristics of the Generating Unit and the Common Facilities, the quality and quantity of fuel available, the rights and obligations of the Participants under the Project Agreements, and any other special circumstances affecting the Station Work.

10.3.30 Execute, enforce, and comply with all contracts entered into in the name of the Project Manager, acting as principal on its own behalf and as agent for the other Participant, in connection with the performance of Station Work which has been authorized by the Management Committee.

10.3.31 Furnish and train the necessary personnel for performance of Station Work.

10.3.32 Comply with any and all laws and regulations applicable to the performance of Station Work.

10.3.33 Purchase and procure, with the approval of the Management Committee, the equipment, apparatus, machinery, tools, materials and supplies and spare parts necessary for the performance of Station Work, however, the Project Manager shall not need such approval for any purchase costing less than $15,000.

10.3.34 Keep and maintain records of monies received and expended, obligations incurred, credits accrued, and contracts entered into in connection with the performance of Station Work and make such records available for inspection by the other Participant at reasonable times and places.

10.3.35 Keep each Participant fully and promptly advised of major changes in conditions or other major developments which affect the performance of Station Work, and furnish each Participant with copies of any notices given or received pursuant to the Project Agreements.

10.3.36 Determine Net Effective Generating Capabilities, Minimum Net Generation and other capacities for each Generating Unit and several Generating Units.

10.3.37 Upon the request of either Participant, provide such Participant a copy of any report, record, list, budget, manual, accounting or billing summary, classification of accounts or other documents or revisions of any of the aforesaid items, all as prepared in accordance with this Participation Agreement.

10.3.38 Administer and enforce all Project Agreements with Third Parties relating to Station Work.

10.3.39 Accept and supervise deliveries of fuel for the Project in accordance with the applicable agreements.

10.3.40 Keep each Participant fully and promptly informed of any known default of the Project Agreements.

10.3.41 Periodically test or arrange for testing of all meters used to measure Power and Energy. Either Participant may ask for a test of such meters, and it will be the duty of the Project Manager to inform the other Participant in advance so it may have representatives present at such test. Any such test shall be held at a reasonable time and each Participant shall bear its own Costs therefor.

10.3.42 Maintain plant charts and operating records as may be required for reporting to regulatory agencies having jurisdiction.

10.3.43 Establish, periodically review and from time to time, revise and submit to the Management Committee for review and approval the following information:

10.3.43.1 Manning requirements and manning table including administrative, engineering, operating and maintenance personnel.

10.3.43.2 Safety procedures for the protection of personnel, for removing equipment and systems, including clearance procedures for removing equipment from service for inspection, test and maintenance.

10.3.43.3 A book of "Plant Operation Orders" listing all permanent or semipermanent instructions to operating personnel.

10.3.43.4 A book of "Equipment Operating Instructions" outlining standard procedures for equipment and systems startup, operation and shutdown.

10.3.43.5 A book of "Preventative Maintenance Instructions and Schedules" outlining standard procedures, schedules and testing for performing mechanical, electrical, and instrument maintenance.

10.3.43.6 Procedures for training operating and maintenance personnel.

10.3.44 Prepare and submit to the Management Committee recommendations for the acquisition of necessary water supply and water rights.

11. CONSTRUCTION SCHEDULES:

11.1 Construction of the Project has been planned with the objective of having Unit 1 available for Firm Operation by April 1978.

12. CONSTRUCTION COSTS:

12.1 Construction Costs shall consist of payments made and obligations incurred (other than obligations for interest during construction) for the account of Construction Work and shall consist of, but not be limited to, the following:

12.1.1 All costs of labor, services and studies performed in connection with Construction Work, if authorized and approved as provided herein.

12.1.2 Payroll and other expenses of the Project Manager's employees while performing Construction Work, including properly allocated labor loading charges, such as department overhead, time-off allowances, payroll taxes, workmen's compensation insurance, retirement and death benefits and employee benefits.

12.1.3 All components of Construction Costs, including overhead costs associated with construction (including the allowance for the Project Manager's administrative and general expenses described in Section 12.4 hereof), costs of temporary facilities, land and land rights, structures and improvements, and equipment for Unit 1, in accordance with FPC Accounts.

12.1.4 All costs and expenses, including those of outside consultants and attorneys, incurred by the Project Manager for construction and operating certificates, licenses and permits, and with respect to environmental laws, rules and regulations, to land and water rights, to fuel requirements and supply and the acquisition thereof, and to the preparation of agreements relating to Construction Work with entities other than the Participants.

12.1.5 Applicable costs of materials, supplies, tools, machinery, equipment, apparatus, initial Spare Parts, construction power and construction water in connection with Construction Work, including rental charges.

12.1.6 All costs of Construction Insurance, all costs of any loss, damage or liability arising out of or caused by Construction Work which are not satisfied under the coverage of Construction Insurance, and the expenses incurred in settlement of injury and damage claims, including the costs of labor and related supplies and expenses incurred in injury and damage activities (all as referred to in FPC Account 925), because of any claim arising out of or attributable to the construction of Unit 1 and the Common Station Facilities, or the past or future performance or nonperformance of Construction Work, including but not limited to any claim resulting from death or injury to persons or damage to property.

12.1.7 All federal, state or local taxes of any character imposed upon Construction Work, except any tax assessed directly against an individual Participant unless such tax was assessed to such individual Participant on behalf of both Participants.

12.1.8 All costs and expenses of enforcing or attempting to enforce the provisions of Construction Insurance policies, payment and performance bonds, contracts executed as Project Manager and warranties extending to Project Facilities.

12.2 In cases where the allocation of a cost item is made between Construction Work and any other work, such allocation shall be made on a fair and equitable basis in accordance with established accounting procedures.

12.3 The Project Manager shall use the FPC Accounts to account for Construction Costs in the Final Completion Report and any supplement thereto.

12.4 The allowance for the Project Manager's administrative and general expenses to cover the costs of services rendered by it in the performance of Construction Work and Capital Improvement shall be allocated monthly at the rate of one percent (1%) of Construction Costs and Capital Improvement Costs incurred during the preceding month, excluding from such costs:

12.4.1 Any allowance for administrative and general expenses provided for in this Section 12.4.

12.4.2 Expenses described in Sections 12.1.6 and 12.1.7 hereof.

until the end of the Project Manager's fiscal year. After the end of such fiscal year, such allowance shall be subject to review and adjustment as recommended by the Independent Certified Public Accountants selected by the Management Committee under Section 9.3.8 hereof. The rate of such allowance shall be adjusted to actual at the end of each fiscal year and the adjusted rate shall be used in preparation of revised billings to the Participants and as the basis for allocating such administrative and general expense during the next succeeding fiscal year.

13. <u>ADVANCES DURING CONSTRUCTION</u>:

13.1 The Participants shall, during the course of and until the final completion of Construction Work, advance to the Project Manager such funds as shall enable it to pay estimated Construction Costs (including estimated administrative and general expenses) in order that the Project Manager in its capacity as such will not have to advance funds on behalf of the other Participant.

13.2 During the course of Construction Work, each Participant shall advance funds to the Construction Account to cover estimated Construction Costs in proportion to its percentage of ownership in the Construction Work being performed.

13.3 Funds shall be advanced by the Participants to the Project Manager in response to a Request for Funds, within five (5) working days after receipt by such Participant of the Request for Funds. Funds on hand will be invested to the maximum extent possible. Net earnings or losses will be allocated to the Participants on the basis of funds advanced. Funds shall be requested as near to the date such funds are required by the Project Manager as is practical under the circumstances.

13.4 The sum of the advances by the Participants hereunder shall not exceed 100 percent of the total Construction Costs estimated to be expended during the period specified in the Request for Funds.

13.5 Funds not advanced to the Project Manager on or before the due date specified in Section 13.3 hereof shall be payable with interest, if any, accrued as provided in Section 27.3 hereof.

13.6 If a Participant shall dispute any portion of any amount specified in a Request for Funds, the disputant shall make the total payment specified in the Request for Funds under protest as provided in Section 27.4 hereof.

13.7 When the total and final Construction Costs have been incurred and calculated, each Participant shall pay any deficit between total advances made by it and its share of said total and final Construction Costs or shall be reimbursed for any credit between said total advances made by it and its share of said total and final Construction Costs by the other Participant.

14. OPERATION AND MAINTENANCE EXPENSES:

14.1 In determining the expenses of Station Work, the Project Manager shall include the following expenses, to the extent that they are chargeable to the project, in accordance with FPC Accounts:

14.1.1 The operation expenses chargeable to FPC Accounts 500, 502, 503, 504, 505, 506, 507, 556, 557 and 563 and related expenses which shall include overhead expenses, labor loading charges (which shall include, but not be limited to, time off allowance, employee payroll taxes chargeable to FPC Account 408, employee pensions and benefits chargeable to FPC Account 926 and workmen's compensation insurance chargeable to FPC Account 925), and administrative and general expenses. The related expenses as provided for herein shall be charged to the FPC accounts referred to in the manner set out in 14.1.3 hereinbelow.

14.1.2 The maintenance expenses chargeable to FPC Accounts 510 through 514 and 571 and related expenses which shall include overhead expenses, labor loading charges (which shall include, but not be limited to, time off allowance, employee payroll taxes chargeable to FPC Account 408, and employee pensions and benefits chargeable to FPC Account 926 and workmen's compensation insurance chargeable to FPC Account 925). The related expenses as provided for herein shall be charged to the FPC accounts referred to in the manner set out in 14.1.3 hereinbelow.

14.1.3 Overhead expenses, labor loading charges and administrative and general expenses referred to in 14.1.1 and 14.1.2 above shall be charged in the following manner:

14.1.3.1 Unemployment and FICA taxes, costs of pension benefits and workmen's compensation and public liability insurance costs which are directly related to labor costs incurred which are chargeable to the FPC accounts referred to in this Section 14 shall be charged as a part of direct labor costs.

14.1.3.2 Costs of time off pay for holidays, annual and sick leave, military leave, and jury service applicable to individuals whose labor costs are chargeable to the FPC accounts referred to in this Section 14 shall be charged to the above accounts as a percentage of the direct labor costs of such individuals which are chargeable thereto. Not less frequently than once a year a study shall be made of such time off pay costs and a revised percentage basis for such charges shall then be established.

14.1.3.3 Administrative and general expenses shall be calculated and charged monthly as a percentage of costs of Station Work performed by the Project Manager. Such percentage shall be determined annually as of March 31 by an overhead and indirect cost study of the Project Manager's costs for administrative and general expenses for the year then ended, which study shall be subject to review and approval by the firm of Independent Certified Public Accountants as provided in Section 9.3.8 hereof. Appropriate adjustments based on such study and review will be made in the amounts charged each of the Participants for administrative and general expenses prior to the end of the Project Manager's fiscal year in which the amount of the adjustment is determined.

14.2 In the event additional Generating Units are constructed, expenses described in Section 14.1.1 hereof shall be apportioned to each of the units, including Common Station Facilities, in the ratio that the Net Effective Generating Capability of each Unit bears to the Aggregate Net Effective Generating Capability of the Project.

14.3 Expenses described in Section 14.1.2 hereof shall be charged directly to Unit 1 and to each Additional Generating Unit or the Common Station Facilities, as the case may be. The expenses so charged directly to the Common Station Facilities shall be apportioned between Unit 1 and each Additional Generating Unit, if any there be, in the ratio that the Net Effective Generating Capability of Unit 1 and of each Additional Generating Unit bears to the aggregate Net Effective Generating Capability of the Project.

14.4 Either Participant may request that the method used to determine the Project Manager's payroll tax expenses, employee workmen's compensation insurance expenses, employee pensions and benefits expenses, and administrative and general expense be submitted to the Management Committee for review if such Participant believes that such method results in an unreasonable burden on it; provided, that such review may be requested only after one year from the Date of Firm Operation, and thereafter at intervals of not less than two (2) years each. After any such request the Management Committee shall review said method and shall attempt to determine whether or not said unreasonable burden does exist. If after such review the Management Committee determines that the application of said method does result in an unreasonable burden on either of the Participants, the Management Committee shall determine and recommend a modified method to the Project Manager so that such unreasonable burden would be eliminated if such modified method is adopted by the Project Manager. If after such review the Management Committee is unable to agree on whether or not such unreasonable burden does exist or is unable to agree on said modified method for eliminating said unreasonable burden, the Management Committee shall submit the entire matter to a nationally recognized firm of Independent Certified Public Accountants for decision and recommendation of a modified method if one is found to be justified.

14.5 Any modified method adopted by the Management Committee or determined through arbitration shall not be retroactive and shall become effective on the first day of the Project Manager's fiscal year next following such adoption or determination. Said modified method shall stay in effect no less than two years.

15. <u>INITIAL TRAINING EXPENSES</u>:

15.1 The initial training expenses shall consist of labor, material, transportation, services and any other costs applicable to hiring and training, including any relocation of personnel, for Station Work.

15.2 Initial training expenses shall also include departmental overheads, time-off allowances, payroll taxes, employee pensions and benefits, Workmen's Compensation, and administrative and general expenses determined in accordance with Section 14 hereof.

15.3 The Project Manager shall accumulate the initial training expenses up to but not beyond the Date of Firm Operation in a manner to provide identification, but such expenses shall be included in Construction Work billing.

16. <u>ADVANCEMENT OF OPERATING FUNDS</u>:

16.1 Not less than thirty (30) days prior to incurring any operating cost on behalf of the Participants pursuant to this Participation Agreement, the Project Manager shall establish the Operating Account. The Project Manager shall notify the Participants in writing of the establishment of the Operating Account not later than five (5) days following its establishment.

16.2 All Operating Funds required to be advanced by the Participants in accordance with this Participation Agreement shall be paid into the Operating Account, or may be credited to the Operating Account by interbank transfers. All Operating Funds shall be deposited in the Operating Account, and the Project Manager shall, unless otherwise agreed to by both Participants, make disbursements from the Operating Account only for expenditures or obligations incurred by it in the performance of Operating Work.

16.3 Not less than sixty (60) days prior to the establishment of the Operating Account, the Management Committee shall establish a minimum amount for the Operating Account so that the Project Manager will have Operating Funds to pay for expenditures or obligations incurred by the Project Manager pursuant to this Participation Agreement. Such minimum amount may be revised by the Management Committee at any time. The original minimum amount and any increase therein shall be allocated among the Participants in accordance with their Common Station Facilities Ownership Shares and shall be due and payable within fifteen (15) business days following notification of the establishment of the Operating Account or the date on which any increase in such minimum amount shall become effective. In the event the Management Committee authorizes a decrease in such minimum amount, then each Participant shall receive a credit which shall be equal to its Common Station Facilities Ownership Share.

16.4 Each Participant shall advance Operating Funds to the Operating Account on the basis of bills it receives from the Project Manager which reflect such Participant's share of costs and expenses determined in accordance with this Participation Agreement as follows:

16.4.1 Expenses described in Sections 14, 15, and 19 hereof for the current month shall be billed on an estimated basis on or before the first business day of each such month and payment shall be due and payable by the 15th day of such month; provided, that adjustments for actual expenses incurred for such month shall be reflected in the bill for the month which follows the date of determination of such actual expenses.

16.4.2 Expenses described in Sections 20 and 25 (excluding workmen's compensation insurance), hereof shall be billed not less than eight (8) business days prior to their due date and shall be due and payable within three (3) business days following receipt of the invoice. If such expenditures or obligations do not have a specified due date, they shall be billed within a reasonable time following the incurrence of such expenditures or obligations and shall be due and payable within five (5) business days following receipt of the bill.

16.4.3 The expenditures or obligations described in Section 19 hereof, for coal consumed, shall, if necessary, be billed on an estimated basis, to be adjusted in the next monthly billing. Advances to cover billings for coal shall be made as close to the due date of the coal suppliers' billing as practicable.

16.5 Operating Funds not advanced to the Project Manager on or before the due date specified shall be payable with interest, if any, accrued as provided in Section 27 hereof.

16.6 If a Participant shall dispute any portion of any amount specified in a request for Operating Funds, the disputant shall make the total payment specified in the request for Operating Funds under protest as provided in Section 27 hereof.

16.7 Within forty-five (45) days following the end of each calendar year the Project Manager shall submit to each of the Participants a final accounting for such calendar year showing all amounts deposited into and expended from the Operating Account and the apportionment of such expenditures among the Participants. Adjustments shall be made among the Participants, if required, so that all costs incurred in the performance of Station Work shall have been shared by each Participant in accordance with this Participation Agreement.

17. ANNUAL BUDGETS:

17.1 At least one hundred twenty (120) days before the commencement of the initial training period for the personnel that will perform Station Work, the Project Manager shall prepare and submit to the Management Committee for its review and approval a budget (manning and dollars) for training such personnel. The Management Committee shall approve a training budget not less than sixty (60) days prior to the commencement of said initial training period.

17.2 Not less than one hundred sixty (160) days prior to the Date of Firm Operation of Unit 1, and by July 1st of the year preceding each calendar year thereafter, the Project Manager shall prepare and submit to the Management Committee for its review and approval the proposed annual capital expenditures budget, annual manpower budget, and annual operating and maintenance budget for Station Work for the initial year of operation and for each succeeding calendar year, respectively.

17.3 Not less than sixty (60) days prior to the Date of Firm Operation of Unit 1 and by August 1st of the year preceding each calendar year thereafter, the Management

Committee shall approve an annual capital expenditures budget, annual manpower budget, and annual operating and maintenance budget. If these budgets or any one of them are not approved by the Management Committee in final form prior to the beginning of the next calendar year, the Project Manager shall nevertheless continue to perform Station Work in accordance with Section 29 hereof until such time as a budget has been approved or otherwise determined in accordance with the Project Agreements.

17.4 Any information required from the Participants by the Project Manager in preparing the aforesaid proposed budgets shall be supplied by the Participants, if possible, within thirty (30) days following a request by the Project Manager.

17.5 The Management Committee may at any time during the year approve revisions to the annual capital expenditures budget, annual manpower budget, and the annual operating and maintenance budget for Station Work.

18. FUEL SUPPLY AND WATER SUPPLY:

18.1 The Project Manager shall solicit and obtain bids and contract proposals from coal suppliers to supply coal to the Project and shall submit such bids and proposals to the Management Committee for review and approval. Any fuel supply contracts approved by the Management Committee shall be then submitted to the Participants. Both Participants shall execute any fuel contracts.

18.2 Each Participant, in the absence of other agreement, shall have the option to furnish its share of all necessary water supply from independent sources including existing water rights or rights which may be obtained.

19. FUEL COST ALLOCATION:

19.1 The cost of purchasing a stockpile of coal shall be apportioned to the Participants in proportion to their cost responsibility for Common Station Facilities.

19.2 In the event of more than one Generating Unit, it shall be the responsibility of the Project Manager to assure that the coal moving to the bunkers of each Unit shall be weighed and sampled separately. The cost of coal burned in each respective unit in each calendar month as reflected by invoices submitted by the coal suppliers and related costs chargeable to FPC Account 501 shall be in accord with the quantity of coal weighed and sampled during the movement into the bunkers of the respective Units.

19.3 The cost of coal allocated to each respective Unit pursuant to Section 19.2 and the cost of other fuel shall be apportioned to each Participant in the ratio that each Participant's monthly Net Energy Generation scheduled from such Unit bears to the total monthly Net Energy Generation scheduled from such Unit.

19.4 The costs of ash disposal chargeable to FPC Account 501 shall be apportioned to the Participants in the same proportions as the apportionment of monthly coal costs.

20. TAXES:

20.1 To the extent the same may be taxable, each Participant shall render for ad valorem taxation its undivided interest in the jointly owned property comprising the Project and shall otherwise use its best efforts to have any taxing authority imposing any such taxes or assessments on the Project, or any interest or rights therein, assess and levy such taxes or assessments directly against the ownership or beneficial interest of each Participant.

20.2 To the extent of any taxes or assessments collectible against or with respect to each Participant's interest in, or pro rata share of, the purchase, use, ownership or beneficial interest in the Project, the same shall be the sole responsibility of, and shall be paid by, the Participant upon whose purchase, use, ownership or beneficial interest said taxes or assessments are levied.

20.3 If any property taxes or other taxes or assessments are legally and properly levied or assessed other than against each Participant as contemplated in Sections 20.1 and 20.2 hereof (that is, are levied or assessed in such a way as to be disproportionately collected from one or both Participants), such taxes or assessments shall be apportioned between the Participants in accordance with their respective ownership interest or Power or Energy entitlement or take, whichever is appropriate to the incidence of the tax.

20.4 The Participant claiming exemption from any taxes or assessments shall be responsible for and shall pay all expenses in connection with the sustaining or determination of such claims and the other Participant, the Management Committee and the Project Manager shall lend all reasonable cooperation in connection with the filing of tax renditions and reports and in connection with the making of protest and payment under protest as may be requested by each Participant claiming an exemption.

21. WAIVER OF RIGHT TO PARTITION:

21.1 Each Participant hereto agrees to waive any rights which it may have to partition any component of the Project, whether by partition in kind or by sale and division of the proceeds, and further agrees that it will not resort to any action in law or in equity to partition such component, and it waives the benefits of all laws that may now or hereafter authorize such partition for a term (i) which shall be coterminous with the co-tenancy agreement for such component, or (ii) which shall be for such lesser period as may be required under applicable law.

22. MORTGAGE AND TRANSFER OF INTERESTS:

22.1 Each Participant shall have the right at any time and from time to time to mortgage, pledge, create or provide for a security interest in or convey in trust all or a part of its ownership share in the Project, together with an equal interest in this Participation Agreement and the Project Agreements, to a trustee or trustees under deeds of trust, mortgages or indentures, or to secured parties under a security agreement, as security for its present or future bonds or other obligations or securities, and to any successors or assigns thereof, without need for the prior written consent of the other Participant, and without such mortgagee, trustee or secured party assuming or becoming in any respect obligated to perform any of the obligations of the Participant arising prior to such time as such mortgagee, trustee or secured party obtains possession of or assumes the right to exercise such Participant's rights in respect of such ownership share, or after such possession or assumption ceases.

22.2 Any mortgagee, trustee or secured party under present or future deeds of trust, mortgages, indentures or security agreements of either of the Participants and any successor or assign thereof, and any receiver, referee or trustee in bankruptcy or reorganization of either of the Participants, and any successor by action of law or otherwise, and any purchaser, transferee or assignee of any thereof may, without need for the prior written consent of the other Participant, succeed to and acquire all of the rights, titles and interests of such Participant in the Project and in this Participation Agreement and the Project Agreements, and may take over possession of or foreclose upon said property rights, titles and interests of such Participant.

22.3 Each Participant shall have the right to transfer or assign all its ownership share in the Project, together with a proportionate part of its rights under this Participation Agreement and the Project Agreements, to any of the following without the need for prior written consent of the other Participant:

22.3.1 To any entity acquiring all or substantially all of the electric utility properties and business of such Participant; or

22.3.2 To any entity merged or consolidated with such Participant; or

22.3.3 To any entity which is wholly-owned by such Participant.

22.4 Except as otherwise provided in Sections 22.1 and 22.2 hereof, any successor to the rights, titles and interests of a Participant in the Project shall assume and agree in writing to fully perform and discharge all of the obligations hereunder of such Participant, and such successor shall notify the other Participant in writing of such transfer, assignment or merger, and shall furnish to the other Participant evidence of such transfer, assignment or merger.

22.5 No Participant assigning or transferring an interest under this Section 22 or Section 23 shall be relieved of any of its obligations under this Participation Agreement or the Project Agreements but shall remain liable and obligated for the performance of all of the terms and conditions of this Participation Agreement and the Project Agreements, unless otherwise agreed by the remaining Participant.

23. RIGHT OF FIRST REFUSAL:

23.1 Except as provided in Section 22 hereof, should either Participant, prior to the expiration of the period described in Section 21.1 hereof, desire to transfer its ownership in the Project to any person or entity, ready, able and willing to acquire same, the Participant desiring to make such transfer shall obtain a written offer from the prospective transferee, setting forth the consideration and other terms of the offer, and the other Participant shall have the right of first refusal to acquire such interest on the basis of the following consideration:

23.1.1 If the offer is in cash, whether payable in one payment or in installments, the amount of the bona fide written offer from the prospective transferee, payable as specified in the offer; or

23.1.2 If the offer is not in cash but is in securities having a readily ascertainable market value, the fair market value of the securities offered by the prospective transferee; or

23.1.3 If the offer is neither in cash nor in securities having a readily ascertainable market value, the fair market value of the ownership interest to be transferred.

23.2 At least seven (7) months prior to the date on which the intended transfer is to be consummated, the Participant desiring to transfer shall serve written notice of its intention to do so upon the other Participant. Such notice shall contain the proposed date of transfer and the terms and conditions of the transfer.

23.3 The other Participant shall have the option to acquire the interest to be transferred and shall exercise said option by serving written notice of its intention upon the Participant desiring to transfer within three (3) months after service of the written notice of intention to transfer given pursuant to Section 23.2 hereof. Failure of a Participant to exercise said option as provided herein within the time period specified shall be conclusively deemed to be an election not to exercise said option.

23.4 When the option to acquire said ownership has been exercised, the Participants shall thereby incur the following obligations:

23.4.1 The Participant desiring to transfer the ownership interest and the Participant having exercised the option to acquire such ownership interest shall be obligated to proceed in good faith and with due diligence to obtain all required authorizations and approvals of such acquisition.

23.4.2 The Participant desiring to transfer such ownership interest shall be obligated to obtain the release of any lien encumbering the ownership interest which is the subject of the transfer at the earliest practicable date.

23.4.3 The Participant having exercised the option to acquire such ownership interest shall be obligated to perform all of the terms and conditions required of it to complete the acquisition of said ownership interest.

23.5 The acquisition of the ownership interest by the Participant having elected to acquire the same shall be fully consummated within seven (7) months following the date upon which all notices required to be given under this Section 23 have been duly served.

23.6 If the Participant receiving notice of the proposed transfer fails to exercise its option to acquire the ownership interest to be transferred, the Participant desiring to transfer such interest shall be free to transfer such interest, to the party that made the offer referred to in said bona fide written offer. If such transfer is not consummated by the proposed date of transfer referred to in

Section 23.2 hereof, the Participant desiring to transfer said ownership interest must give another complete new right of first refusal to the other Participant pursuant to the provisions of this Section 23 before such Participant shall be free to transfer said ownership interest to another party.

23.7 The Participant who acquires an ownership interest pursuant to this Section 23 shall receive title to and shall own the interest as a tenant in common, subject to the same rights, duties and obligations as are applied by this Participation Agreement and by the Project Agreements to the interest being transferred in the hands of the transferring Participant.

23.8 Any party who may succeed to an ownership interest pursuant to this Section 23 shall specifically agree in writing with the remaining Participant at the time of such transfer that it will not transfer or assign all or any portion of such ownership interest without complying with the terms and conditions of this Section 23.

24. <u>DESTRUCTION OR ABANDONMENT</u>:

24.1 If a Generating Unit should be damaged or destroyed to the extent that the estimated cost of repairs, replacement or reconstruction is not more than one hundred percent (100%) of the aggregate amount of the proceeds from property damage insurance carried and covering the cost of the repairs, replacement or reconstruction of such Generating Unit, the Participants, unless otherwise unanimously agreed, shall repair, replace or reconstruct such Generating Unit to substantially the same general character or use as the original. The Participants shall share the costs of such repairs, replacement or reconstruction in proportion to their Generation Entitlement Shares in the Generating Unit so destroyed.

24.2 If a Generating Unit should be damaged or destroyed to the extent that the estimated cost of repairs, replacement or reconstruction is more than one hundred percent (100%) of the aggregate amount of the proceeds from property damage insurance carried and covering the cost of the repairs, replacement or reconstruction of such Generating Unit, the Participants shall, upon agreement, repair, replace or reconstruct such Generating Unit to substantially the same general character or use as the original; provided, however, that should the Participants not agree to repair, replace or reconstruct such Generating Unit, then any Participant who does not agree to repair, replace or reconstruct shall sell its interest in such Generating Unit together with the corresponding interest in the Common Station Facilities to the Participant desiring to repair, replace or reconstruct such Generating Unit for a price equal to the selling Participant's proportionate interest in the salvage value of such Generating Unit plus such Participant's proportionate cost, less depreciation at the maximum straight line rates then applicable to like properties under the Federal income tax law, in the interest in the Common Station Facilities so sold.

24.3 If any of the Common Station Facilities should be destroyed, the Participants shall, unless otherwise agreed, repair or reconstruct same to substantially the same character or use as the original. The Participants shall share the costs of such repair or reconstruction in proportion to their Plant Ownership Interests.

25. PROJECT INSURANCE:

25.1 The Project Manager shall recommend to the Management Committee, and the Management Committee shall determine, the insurance coverages, including the insurable values, limits, deductibles, retentions and other special terms, and the insurance carriers from which such insurance is to be obtained during the periods covered by and with respect to Construction Work and Station Work or any phases thereof.

25.2 All policies of Project Insurance shall:

25.2.1 Provide insurable values, limits, deductibles, retentions and other special terms as determined by the Management Committee;

25.2.2 List as loss payees or additional insureds (as their interests may appear) such mortgagees, trustees or secured parties as a Participant, by written notice to the Project Manager, may designate;

25.2.3 Contain endorsements providing for positive notice of cancellation to all parties listed as named or additional insureds;

25.2.4 Contain endorsements providing that the insurance is primary insurance for all purposes; and

25.2.5 Contain cross-liability endorsements for comprehensive bodily injury liability and property damage liability coverages.

25.3 The following procedures shall be observed in connection with the procurement of Project Insurance and Changes in Project Insurance:

> 25.3.1 The Project Manager shall give prompt written notice to the Management Committee of the procurement of all insurance binders.
>
> 25.3.2 The Project Manager shall furnish each Participant with either a certified copy of each of the policies of the insurance procured or a certified copy of each of the policy forms therefor, together with a line sheet therefor (and any subsequent amendments) naming the insurers and underwriters and the extent of their participation.
>
> 25.3.3 No policy of Project Insurance obtained pursuant to decision of the Management Committee shall be materially changed without the prior written consent of the Management Committee.
>
> 25.3.4 Any changes in policies of Project Insurance shall be promptly reported to the Management Committee by the Project Manager.

25.4 Each Participant, at its expense, shall have the right to secure such additional or different insurance coverage as may be required under any mortgage or contract provision, and, to the extent practicable, such additional or different insurance coverage may be effected through endorsements on policies of Project Insurance.

26. LIABILITY OF PARTICIPANTS TO EACH OTHER:

26.1 Participants shall have no remedies against the other Participant for tortious conduct arising out of the ownership of the Project, or any portion thereof, or out of Construction Work or Station Work except when the claim results from Willful Action.

26.2 Remedies of a Participant with respect to a claim against the other Participant shall be unimpaired by this Participation Agreement when the claim does not arise out of ownership of the Project or any portion thereof, or out of Construction Work or Station Work.

26.3 Each Participant shall protect, indemnify, and hold the other Participant, and its directors, officers and employees, free and harmless from and against any and all claims, demands, causes of action, suits or other proceedings (including all costs in connection therewith and in connection with the defense thereof, including attorneys' fees) of every kind and character arising in favor of any of that Participant's electric customers (or anyone claiming through that Participant's electric customers) on account of bodily injuries, death, damage to property or economic loss in any way occurring, incident to, arising out of or in connection with the furnishing of, or failure to furnish, electric service to such customers, it being the intention of this Section 26.3 to impose on each Participant the sole responsibility for the defense and discharge of such claims, demands, causes of action, suits or other proceedings brought against one or both Participants by a Participant's customers even when caused by the sole fault of the other Participant. Nothing in this Section 26.3 shall impair the remedies of a Participant against the other Participant preserved by Sections 26.1 and 26.2 hereof.

26.4 The terms "Participant" and "Participants," as used in this Section 26, shall include the Project Manager in its capacity as such.

27. DEFAULTS AND COVENANTS REGARDING OTHER AGREEMENTS:

27.1 Each Participant hereby agrees that it shall pay all monies and carry out all other duties and obligations agreed to be paid or performed by it pursuant to all of the terms and conditions set forth and contained in the Project

Agreements, and a default by either Participant in the covenants and obligations to be by it kept and performed pursuant to the terms and conditions set forth and contained in any of the Project Agreements shall be an act of default under this Participation Agreement.

27.2 In the event of an alleged default by either Participant in any of the terms and conditions of the Project Agreements concerning the advancement of funds, then, within ten (10) days after written notice has been given by the nondefaulting Participant to the defaulting Participant of the existence and nature of the default, the nondefaulting Participant shall remedy such default by advancing the necessary funds or commencing to render the necessary performance.

27.3 In the event of an alleged default by either Participant in any of the terms and conditions of the Project Agreements and the giving of notice as provided in Section 27.2 hereof, the defaulting Participant shall take all steps necessary to cure such default as promptly and completely as possible and shall pay promptly upon demand to the nondefaulting Participant the total amount of money or the reasonable equivalent in money of nonmonetary performance, if any, paid or made by such nondefaulting Participant in order to cure any default by the defaulting Participant, together with interest on such money or the costs of nonmonetary performance at the commercial prime rate then in effect at the First National City Bank in New York, or at the maximum rate of interest legally chargeable, whichever is the lesser, from the date of the expenditure of such money or the date of completion of such nonmonetary performance by such nondefaulting Participant to the date of such reimbursement by the defaulting Participant, or such greater amount as may be otherwise provided in the Project Agreements.

27.4 In the event that either Participant shall dispute an asserted default by it, then such Participant shall pay the disputed payment or perform the disputed obligation, but may do so under protest. The protest shall be in writing, shall accompany the disputed payment or precede the performance of the disputed obligation, and shall specify the reasons upon which the protest is based. A copy of such protest shall be mailed by such Participant to the other Participant. Payments not made under protest shall be deemed to be correct, except to the extent that periodic or annual audits may reveal over or under payments by Participants, necessitating adjustments. In the event it is determined by arbitration, pursuant to the provisions of this Participation Agreement or otherwise, that a protesting Participant is entitled to a refund of all or any portion of a disputed payment or payments or is entitled to the reasonable equivalent in money of nonmonetary performance of a disputed obligation theretofore made, then, upon such determination, the nonprotesting Participant shall pay such amount to the protesting Participant, together with interest thereon at the commercial prime rate of interest then in effect at the First National City Bank in New York or at the maximum legal rate, whichever is the lesser, from the date of payment or of the performance of a disputed obligation to the date of reimbursement.

27.5 Unless otherwise determined by a board of arbitrators, in the event a default by either Participant in the payment or performance of an obligation under the Project

Agreements shall continue for a period of six (6) months or more without having been cured by the defaulting Participant or without such Participant having commenced or continued action in good faith to cure such default, or in the event the question of whether an act of default continues for a period of six (6) months following a final determination by a board of arbitrators or otherwise that an act of default exists and the defaulting Participant has failed to cure such default or to commence such action during said six (6) month period, then, at any time thereafter and while said default is continuing, the nondefaulting Participant may, by written notice to the defaulting Participant, suspend the right of such defaulting Participant to receive all or any part of its proportionate share of the Net Effective Generating Capability, in which event:

27.5.1 During the period that such suspension is in effect, the nondefaulting Participant shall bear all of the operation and maintenance costs, insurance costs and other expenses otherwise payable by the defaulting Participant under the Project Agreements.

27.5.2 The defaulting Participant shall be liable to the nondefaulting Participant for all costs incurred by such nondefaulting Participant together with interest as provided in Section 27.3 hereof.

27.6 In addition to the remedies provided for in Section 27.5 of this Participation Agreement, the nondefaulting Participant may, in submitting a dispute to arbitration in accordance with the provisions of Section 28 hereof, request that the board of arbitrators determine what additional remedies may be reasonably necessary or required under the circumstances which give rise to the dispute. The board of arbitrators may determine what remedies are necessary or required in the premise, including but not limited to the conditions under which the Project may be operated economically and efficiently during periods when the defaulting Participant's right to receive its proportionate share of the Net Effective Generating Capability is suspended.

27.7 The rights and remedies of the Participants set forth in this Participation Agreement shall be in addition to the rights and remedies of the Participants set forth in any other of the Project Agreements.

28. ARBITRATION:

28.1 If a dispute between the Participants should arise under this Participation Agreement or the Project Agreements, which is not resolved by the Management Committee, either Participant may call for submission of the dispute to arbitration, which call shall be binding upon the other Participant. Except as specifically provided in this Participation Agreement or in the Project Agreements, the arbitration shall be governed by the Texas General Arbitration Act of 1965, as same may be amended at the time of the call for arbitration. The costs and expenses of the arbitrators shall be shared equally by the Participants, unless otherwise decided by the arbitrators.

28.2 A Participant calling for arbitration shall make such call by written notice to the other Participant, naming in such notice one arbitrator. Upon receipt of a written demand for arbitration, the other Participant shall appoint one arbitrator. The arbitrators so appointed shall elect one additional arbitrator. The initial meeting of the arbitrators shall be at a place in Texas named by the Participant making the demand for arbitration. Thereafter, the arbitrators shall meet at such place or places in Texas as they deem appropriate. The decision of a majority of the arbitrators so appointed shall be binding on all Participants, and the Participants hereby consent to the entry of a judgment in any court of competent jurisdiction confirming and implementing the decision of the arbitrators.

29. ACTIONS PENDING RESOLUTION OF DISPUTES:

29.1 Pending the resolution of any dispute by arbitration or judicial proceedings, the Project Manager shall proceed with the Construction Work or Station Work in a manner consistent with this Participation Agreement and the Project Agreements and with the best judgment of the Project Manager, and the Participants shall advance the funds required to perform such Construction Work or Station Work in accordance with the applicable provisions of this Participation Agreement or the Project Agreements.

30. RELATIONSHIP OF PARTICIPANTS:

30.1 The covenants, obligations and liabilities of the Participants shall be several and not joint or collective.

Each Participant shall be individually responsible for its own covenants, obligations and liabilities as herein provided and as provided in the Project Agreements. It is not the intention of the parties to create, nor shall this Participation Agreement nor any of the Project Agreements be construed as creating, a partnership, association, joint venture or trust, as imposing a trust or partnership covenant, obligation or liability on or with regard to either of the Participants, or as rendering the Participants liable as partners or trustees. No Participant shall be under the control of or shall be deemed to control the other Participant. A Participant as such shall not be the agent of or have a right or power to bind the other Participant.

31. <u>ACQUISITION OF REAL PROPERTY INTERESTS</u>:

31.1 The Project Manager shall acquire, or cause to be acquired, in its own name, or in the name of the other Participant, or both, the Plant Site by purchase or eminent domain proceedings, for a cash consideration. The tracts of land constituting the Plant Site shall be acquired in fee simple absolute unless a lesser title is approved by the Management Committee. Acquisition of the Plant Site shall be based upon: (i) title opinions by counsel, title insurance, or other title showings or combinations of showings; and (ii) such survey work and title curative work as the Project Manager in its judgment, reasonably exercised, shall deem necessary; provided that title opinions by counsel approved by the Management Committee shall be procured on all of the Plant Site (except any portions as to which title opinions may be waived by the Management Committee) prior to commencement of the Construction Work. The purchase price for all lands acquired for the Plant Site and all costs and expenses incurred in connection with the acquisition of said lands, including, but not by limitation, title insurance premiums, abstracters, attorneys, surveyors, nominees and land agents fees, title curative work, court costs and recording fees, shall be Construction Costs and borne by the Participants as such. The purchase price for all land acquired through voluntary conveyance shall be approved by the Management Committee.

32. FORCE MAJEURE:

32.1 In the event of any Participant being rendered unable, wholly or in part, by force majeure to perform any of its obligations under this Participation Agreement or the Project Agreements (other than obligations to pay costs and expenses due), upon such Participant giving notice and full particulars of such force majeure in writing or by telephone to the other Participant as soon as reasonably possible after the occurrence of the cause relied upon, the obligations of the Participant giving such notice, so far as it is affected by such force majeure, shall be suspended during the continuance of any inability of performance so caused, but for no longer period. Telephone notices given under the provisions of this Section 32.1 shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the force majeure, the time and date when the force majeure occurred and when the force majeure ceased. This Participation Agreement shall not be terminated by reason of any such cause but shall remain in full force and effect. The term "force majeure" shall mean any cause beyond the control of the Participant affected, including, but not restricted to, failure or threat of failure of facilities or fuel supply, flood, earthquake, storm, fire, lightning, epidemic, war, acts of the public enemy, riot, civil disturbance or disobedience, strike, lockout, work stoppages, other industrial disturbance or dispute, labor or material shortage, sabotage, restraint by court order or other public authority and action or non-action by, or failure to obtain the necessary authorizations or approvals from, any governmental agency or authority, which by the exercise of due diligence such Participant could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Participant to settle any strike, lockout, work stoppage or other industrial disturbance or dispute in which it may be involved. A Participant rendered unable to fulfill any of its obligations under this Participation Agreement or any of the Project Agreements by reason of force majeure shall exercise due diligence to remove such inability with all reasonable dispatch. The term "Participant" as used in this Section 32.1 shall include the Project Manager in its capacity as such.

33. GOVERNING LAW:

33.1 This agreement shall be governed by the laws of the State of Texas, except as to matters exclusively controlled by the Constitution and statutes of the United States of America.

34. BINDING OBLIGATIONS:

34.1 All of the respective covenants, undertakings and obligations of each of the Participants set forth in this Participation Agreement and in each of the Project Agreements shall bind and shall be and become the respective covenants and obligations of each such Participant and, to the extent permitted by law and the existing contracts of the applicable Participant, shall apply to and bind:

34.1.1 All mortgagees, trustees and secured parties under all present and future mortgages, indentures and deeds of trust, security agreements and other financing arrangements which are or may become a lien upon any of the properties of such Participant;

34.1.2 All receivers, assignees for the benefit of creditors, bankruptcy trustees and referees of, or having control or jurisdiction over, such Participant;

34.1.3 All other persons, firms, partnerships, corporations or entities claiming by, through or under any of the foregoing; and

34.1.4 Any successors or assigns of any of those mentioned above in this Section 34.1;

and shall be covenants and obligations running with each Participant's respective rights, titles and interests in the Project and with all of the rights and interests of each Participant under this Participation Agreement and the Project Agreements, and shall be for the benefit of the respective rights, titles and interests of the Participants and their respective successors and assigns, in and to the Project. It is the specific intention of this provision that all such covenants and obligations shall be binding upon any party which acquires any of the rights, titles and interests of a Participant in the Project or in, to and under this Participation Agreement or any of the Project

Agreements and that all of the above-described persons and groups shall be obligated to use such Participant's rights, titles and interests in the Project or in, to or under this Participation Agreement or any of the Project Agreements for the purpose of discharging the covenants and obligations under this Participation Agreement and the Project Agreements.

35. PROJECT AGREEMENTS:

35.1 The Participants hereto agree to negotiate in good faith and to proceed with diligence to obtain and agree upon all of the Project Agreements among the Participants and between the Participants and other entities.

35.2 It is acknowledged by the Participants that one or more of the Project Agreements may contain provisions which are in conflict with or contrary to the terms of this Participation Agreement, and any such provision in a Project Agreement executed subsequent to the execution of this Participation Agreement shall be deemed to supersede, amend or modify any conflicting or contrary provision contained herein. The mutual agreement of the Participants to supersede, amend or modify the terms hereof shall constitute the legal consideration to support such change in the legal rights and obligations of the Participants.

36. REMOVAL OF PROJECT MANAGER:

36.1 The Project Manager shall serve during the term of and pursuant to this Participation Agreement or until it resigns by giving written notice to the other Participant at least one (1) year in advance of the date of resignation or until receipt of notice of its removal following a determination that it is in default of this Participation Agreement as provided in Section 36.2 hereof.

36.2 The following provisions shall apply solely in regard to violations or allegations of violations of this Participation Agreement by the Project Manager on the basis of which removal is sought:

36.2.1 In the event the other Participant shall be of the opinion that an action taken or failed to be taken by the Project Manager constitutes a violation of this Participation Agreement, it may give written notice thereof together with a statement of the reasons for its opinion to the other Participant. Thereupon, the Project Manager may prepare a rebutting statement of the reasons justifying its action or failure to take action. In the event that agreement is not reached between it and the Participant which gave such notice, the matter shall be submitted to arbitration in the manner provided in Section 28 hereof. During the continuance of the arbitration proceedings, the Project Manager may continue such action taken or failed to be taken in the manner it deems most advisable and consistent with this Participation Agreement.

36.2.2 If it is determined that the Project Manager is violating this Participation Agreement, it shall act with due diligence to end such violation, and in any event within six (6) months or within such lesser time following the decision as may be prescribed in the decision, shall take action in good faith to terminate such violation. In the event that the Project Manager has either failed to correct or commence action to correct the violation within such allowed period (which itself may be a subject of dispute for determination as above provided) it shall be deemed in default under this Participation Agreement and shall be subject to removal upon receipt of the notice referred to in Section 36.1 hereof signed by the other Participant.

36.2.3 The provisions of Section 27 hereof shall not apply to disputes as to whether or not an action or nonaction of the Project Manager, in its capacity as such, is a violation of or a default under this Participation Agreement.

36.3 Upon the effective date of resignation or removal, as provided in this Section 36, the Project Manager shall vacate said position and prior thereto the other Participant shall become the new Project Manager. Assumption of duties by the new Project Manager shall constitute its agreement to perform the obligations of said position pursuant to this Participation Agreement.

37. ENVIRONMENTAL PROTECTION:

37.1 In recognition of the need to provide for the greatest feasible degree of environmental protection, the Participants hereby covenant with one another that in the construction and operation of the Project they shall install and operate air quality control equipment and water quality control equipment.

37.2 The Participants, in recognition of all applicable Federal, State and local laws, orders and regulations relating to environmental protection with which they intend to and shall fully comply, and the continuing need for the greatest feasible degree of environmental protection, hereby affirm their understanding and further agree as set forth in Sections 37.3 through 37.5 hereof.

37.3 The Participants shall install and diligently operate in Unit 1 and any additional Units facilities or equipment to comply with applicable Federal, State, or local laws, regulations or standards for the removal of particulate, removal of oxides of sulphur, control of oxides of sulphur and nitrogen and the design of such Units will, to the extent practicable, provide for the future installation of any equipment or facilities required to comply with said Federal, State, or local laws, regulations, or standards.

37.4 The Participants shall install and diligently operate as part of the Project such waste water and waste material control, and sewage control and disposal facilities as are necessary to comply with all applicable Federal, State, and local laws, orders and regulations.

37.5 The Participants shall take appropriate measures to minimize the effect of the plant on the environment and shall recognize and consider the ecology of the area in the design of the Project. In developing plans for Unit 1 and any Additional Generating Units, appurtenant buildings, substations, and coal and water handling facilities, due consideration will be given to minimizing adverse effects to the terrain on which they are located.

38. TERM:

38.1 This Participation Agreement shall become effective when it has been duly executed and delivered on behalf of the parties hereto and shall remain in force and effect, subject to prior termination by unanimous agreement by the Participants, until the abandonment of the Project or such later date as may become the termination date of the last one of the Project Agreements to terminate.

39. INTERESTS ACQUIRED IN THE NAME OF AN INDIVIDUAL PARTICIPANT:

39.1 Any Participant which acquires in its name an interest in any real or personal property or a contractual right which is part of the Project shall acquire and hold same subject to this Participation Agreement and any applicable Project Agreement, and shall transfer and assign an undivided interest therein to the other Participant so that the ownership and rights of the Participants in such property or contract shall be as provided in this Participation Agreement or in the applicable Project Agreements.

40. NOTICES:

40.1 Any notice, demand or request provided for in this Participation Agreement or in the Project Agreements shall be deemed properly served, given or made if delivered in person or sent by registered or certified mail, postage prepaid, to the Participants at the addresses specified below:

City of Austin
P. O. Box 1088
Austin, Texas 78767
Attention: City Manager

Lower Colorado River Authority
P. O. Box 220
Austin, Texas 78767
Attention: Office of the General Manager

40.2 A Participant may, at any time, by written notice to the other Participant, designate different or additional persons or different addresses for the giving of notices hereunder.

40.3 The Project Manager shall provide to each Participant a copy of any notice, demand or request given or received by it in connection with this Participation Agreement or any of the Project Agreements.

41. MISCELLANEOUS PROVISIONS:

41.1 Each Participant agrees, upon request by the other Participant, to make, execute and deliver any and all documents and writings of every kind reasonably requested or required to implement this Participation Agreement and the Project Agreements.

41.2 The captions and headings appearing in this Participation Agreement and in the Project Agreements are inserted merely to facilitate reference and shall have no bearing upon the interpretation thereof.

41.3 Each term, covenant and condition of this Participation Agreement and of the Project Agreements is deemed to be an independent term, covenant and condition, and the obligation of any Participant to perform all of the terms, covenants and conditions to be kept and performed by it is not dependent upon the performance by the other Participant of any or all of the terms, covenants and conditions to be kept and performed by it.

41.4 In the event that any of the terms, covenants or conditions of this Participation Agreement or of any of the Project Agreements, or the application of any such term, covenant or condition, shall be held invalid as to any person or circumstance by any court having jurisdiction in the premises, the remainder of such agreement, and the application of its terms, covenants or conditions to such persons or circumstances shall not be affected thereby.

41.5 The Participants do not intend to create rights in or to grant remedies to any third party as a beneficiary of this Participation Agreement or a Project Agreement or of any duty, covenant, obligation or undertaking established therein.

41.6 Any waiver at any time by a Participant of its rights with respect to a default or any other matter arising in connection with this Participation Agreement or any Project Agreement shall not be deemed a wavier with respect to any subsequent default or matter.

IN WITNESS WHEREOF, the parties hereto have caused this Participation Agreement to be executed as of the 19 day of September 1974.

CITY OF AUSTIN

By ____________________
City Manager

ATTEST:

Grace Monroe
City Clerk ~~Secretary~~

LOWER COLORADO RIVER AUTHORITY

By ____________________
General Manager

ATTEST:

____
Secretary

Signatures of Counsel for Purposes of
The Texas General Arbitration Act:

____
City Attorney, Austin, Texas

____
General Counsel, Lower Colorado
River Authority

FAYETTE POWER PROJECT
PARTICIPATION AGREEMENT
BETWEEN CITY OF AUSTIN & LCRA
EXHIBIT "A"

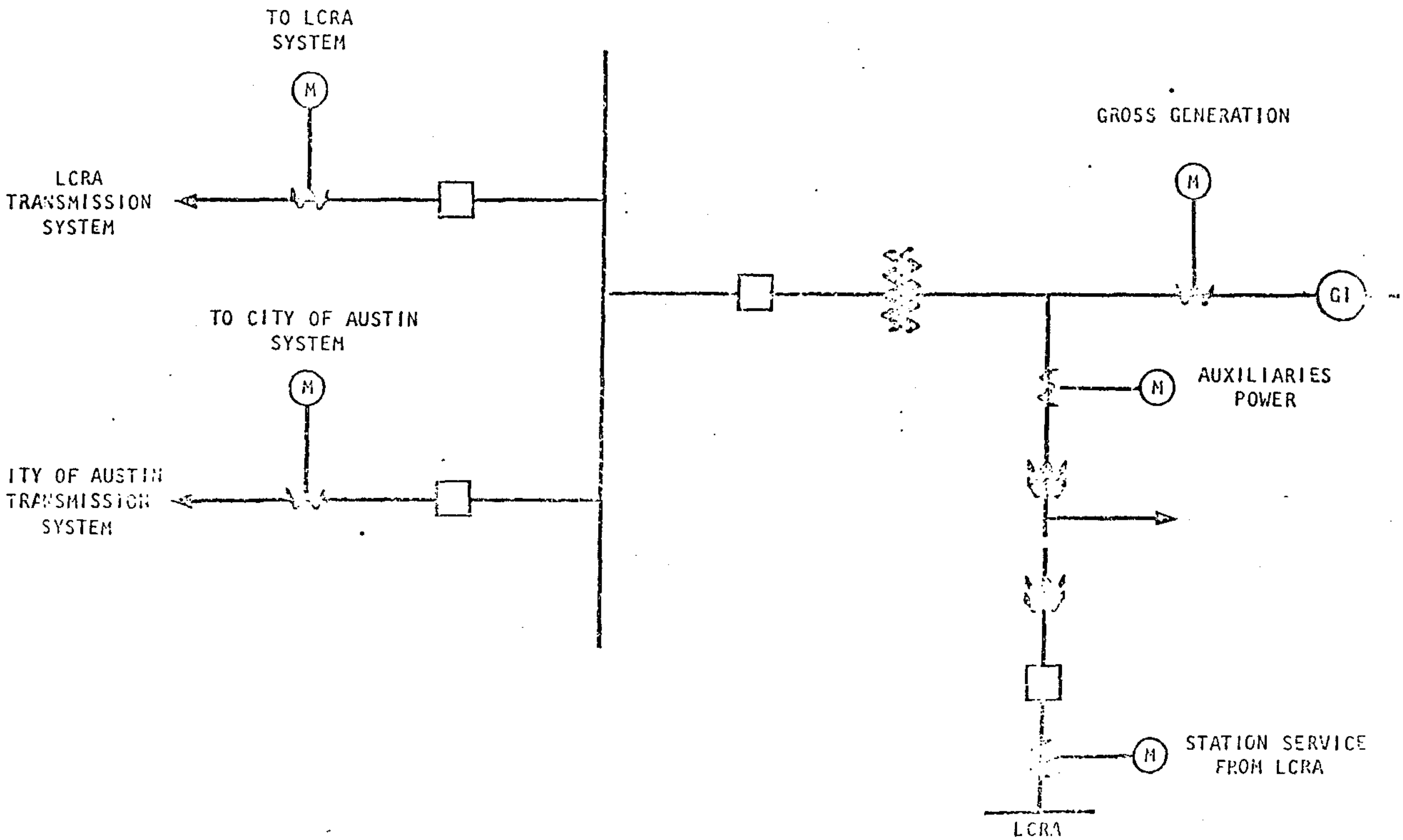


EXHIBIT A

COMMON STATION FACILITIES

The Fayette Power Project will consist of, but not limited to, the following items that will be common to all generating units to be installed at the chosen site:

A. Land for Plant Site and Cooling Lake

The land requirement for the dam, cooling lake, pumping plant, and coal and ash storage is estimated to be 6400 acres. This site will accommodate an ultimate plant capacity of 3000 Mw and will be common for all units.

B. Cooling Lake, Dam and Spillway

The cooling lake is planned to be a staged development in that the initial reservoir will be designed to provide a 2500 acre lake that will accommodate approximately 2200 Mw. The second stage of the development will create approximately 1000 to 1200 acres that will increase the allowable plant capacity to an excess of 3000 Mw.

C. River Pumping Plant and Pipeline

The pumping plant will be constructed on the banks of the Colorado River and a pipeline constructed for a distance of approximately four miles to the plant site and cooling reservoir. This will supply the water for the reservoir and necessary plant use.

D. Railroad Spur

The railroad spur will be constructed from the existing railroad into and out of the plant site for delivery of coal and plant construction material.

E. Coal Handling Facilities

A coal handling system will be provided which will consist of a car dumping facility, underground storage hoppers, stackout tower, a crusher house, and belt conveyor systems. There will also be an area designated for coal storage for the ultimate capacity of the plant.

F. Ash Handling Facilities

Facilities will be constructed consisting of the pump and piping to transport the ash to a disposal area designed to accommodate the total capacity of the plant.

G. Fuel Oil Systems

A fuel oil system will be included consisting of a 20,000 barrel storage tank, burner ignitors and start-up guns using a light "No. 2" fuel oil for start-up of the boiler.

H. Miscellaneous Plant Equipment

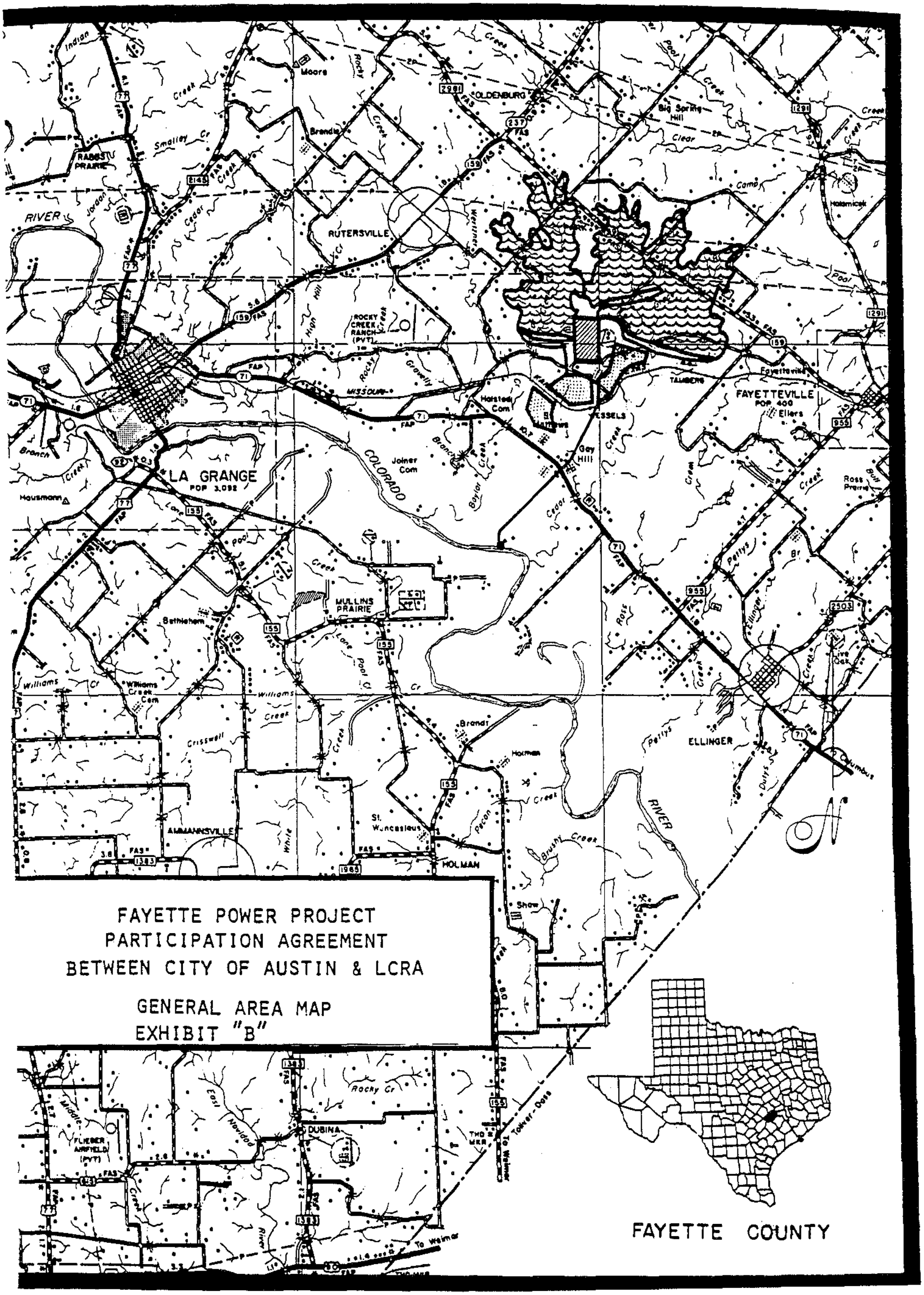
Other common facilities will consist of an administrative building, a machine shop, a warehouse, a maintenance shop, sanitary sewage and waste water treatment, and roadways.

EXHIBIT A

FAYETTE POWER PROJECT UNIT 1

GENERAL DESCRIPTION

Fayette Power Project Unit No. 1 will consist of a 683,700 kva electric generator driven by a 3600 rpm, tandem compound, four-flow reheat, condensing steam turbine having a nameplate rating of 551,922 Kw when supplied with steam at 2400 psig, 1000° F., with reheat to 1000° F., and 3.5" Hg. Abs. exhaust pressure. Steam for the turbine will be supplied from an outdoor western coal/lignite controlled circulation steam-generator having a rating of 4,200,000 pounds per hour. A stacked electrostatic precipitator will allow the unit to meet or exceed all federal and state air pollution regulations while firing sub-bituminous western coal. The plant will be arranged to accommodate future SO_2 removal equipment in the event lignite firing becomes a reality. All associated equipment necessary for an operable coal fired plant will be included as a part of the unit. The turbine generator building and office building will be of rigid frame steel design.


FAYETTE POWER PROJECT
PARTICIPATION AGREEMENT
BETWEEN CITY OF AUSTIN & LCRA
GENERAL AREA MAP
EXHIBIT "B"
FAYETTE COUNTY
LA GRANGE
POP 3,092
FAYETTEVILLE
POP 400
RUTERSVILLE
OLDENBURG
ELLINGER
MULLINS PRAIRIE
AMMANNSVILLE
HOLMAN
DUBINA
COLORADO
RIVER
Moore
Brandle
Bethlehem
Joiner Com
Halsted Com
Gay Hill
Ellers
Ross Prairie
St. Wenceslaus
Shaw
Williams Creek Cem
Hausmann
Rabbs Prairie
FLIEGER AIRFIELD (PVT)
ROCKY CREEK RANCH (PVT)
Big Spring Hill
Halamicek
Columbus
To Weimar

R E S O L U T I O N

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF AUSTIN:

That the City of Austin enter into a participation agreement with Lower Colorado River Authority providing for the construction, operation and maintenance of jointly owned and operated electric generation facilities, to be known as the Fayette Power Project; Lower Colorado River Authority and the City of Austin each owning an undivided fifty percent (50%) interest in said Project, with the Lower Colorado River Authority to act as project manager; and the City Manager is hereby authorized and directed to do such things as may be necessary to effect said participation agreement and to execute same for and on behalf of the City of Austin.

ADOPTED: September 19, 1974. ATTEST: Grace Monroe
City Clerk

19AUG74
DRB:bn

THE STATE OF TEXAS ǁ
COUNTY OF TRAVIS ǁ

I, Grace Monroe, City Clerk of the City of Austin, Texas, do hereby certify that the foregoing instrument is a true and correct copy of a Resolution adopted by the City Council of the City of Austin, Texas, at a regular meeting on the 19th day of September, 19 74, and appears of record in Minute Book 50 of the Minutes of said City Council.

Grace Monroe
City Clerk
City of Austin, Texas

Original

Minute 80-255

1980 AMENDMENT TO FAYETTE POWER PROJECT PARTICIPATION AGREEMENT

This Amendment, made and entered into by and between the City of Austin, a municipal corporation, herein referred to as "Austin," and Lower Colorado River Authority, a public corporation and state agency, herein referred to as "LCRA,"

W I T N E S S E T H:

WHEREAS, on the 19th day of September, 1974, Austin and LCRA entered into the Fayette Power Project Participation Agreement for the construction and operation of electric generating units, herein referred to as "1974 Participation Agreement"; and,

WHEREAS, Austin and LCRA desire to amend the Agreement to reflect refinements in operations;

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth, the parties hereto mutually contract and agree as follows:

I.

Section 4, "Definitions," in the 1974 Participation Agreement is amended by adding the following subsections 4.32, 4.33, 4.34, 4.35, 4.36 and 4.37. These definitions are provided to make more explicit the Texas Interconnected System (TIS) definitions, with which they are intended to be compatible:

4.32 SHORT-TERM FIRM POWER AND ENERGY: Power and Energy that is scheduled to be delivered on demand over a definite period of time less than or equal to twelve (12) months.

4.33 LONG-TERM FIRM POWER AND ENERGY: Power and Energy that is scheduled to be delivered on demand over a definite period of time, said time more than twelve (12) months.

4.34 SPINNING RESERVE: Generating capability reserved to ensure a Participant's system security and/or to meet requirements of the TIS.

4.35 ECONOMY POWER AND ENERGY: Power and Energy producible from previously unscheduled capacity available for sale to third parties on an interruptible basis, usually at a cost less than the third party could produce the same amount of power and energy for itself.

4.36 NON-FIRM POWER AND ENERGY: Power and Energy that is produced either on-peak or off-peak that is specifically agreed to be interruptible under any particular conditions agreed to by the parties involved.

4.37 COST OF FUEL: The cost of coal used to generate power and energy, based on the previous month's cost of coal delivered to the site for the particular generation unit using the last in, first out (LIFO) method of accounting. In the event that actual cost data are not available at a particular billing date, an estimate of the costs will be used as the basis for billing with an appropriate adjustment made to a later month's bill as soon as the actual cost data become available.

II.

Section 7, "Generating Capacity and Entitlements," in the 1974 Participation Agreement is amended by adding the following subsections:

"7.5 In scheduling generating capacity for its account, each Participant shall be entitled to include each of the following to determine its take of generation capacity, it being expressly understood that each Participant shall treat its Entitlement as part of the generation belonging to its own electric power system.

(i) Sufficient capacity to produce the quantity each Participant expects to receive into its own system.

(ii) An allowance for anticipated line loss as provided in the 1977 Fayette Power Project Transmission Agreement.

(iii) Any Spinning Reserve which such Participant desires to carry from its share of the Project Generating Capacity.

(iv) Any short-term or long-term firm Power and Energy sold to a third party.

(v) Any economy, brokerage, or non-firm Power and Energy sold to a third party.

7.6 In the event that a Participant desires to sell Long-Term or Short-Term Firm Power and Energy from its own Entitlement to a third party, such Participant shall obtain a written offer from the prospective purchaser, setting forth the price and terms under which the proposed sale will be made. For Short-Term Firm Power and Energy sales, the selling Participant shall transmit such offer to the other Participant, who shall have two (2) days to elect to purchase such Power and Energy for its own use at the same price and under the same terms as contained in such offer. For Long-Term Firm Power and Energy sales, the selling Participant shall give the other Participant written notice of its intent to sell, including the terms and conditions, and the other Participant shall have thirty (30) days to elect to purchase such Power and Energy for its own use at the same price and under the same terms and conditions. Once this option is exercised, the scheduling shall be made according to Sec. 7.5 (iv) herein. In either case, if the other Participant does not elect to purchase such Power and Energy within the specified time, the selling Participant may proceed with the sale to the third party. This right of first refusal shall apply to each prospective firm sale contract but not to hour-to-hour sales under economy power and energy or to brokerage sales.

7.7 Economy Power and Energy sales by either Participant to third parties shall be made by each Participant individually. The proceeds of any such sale shall be billed and collected independently by each Participant. For the purpose of allocating fuel cost, any Participant's sale of such capacity shall be considered as scheduled capacity for that Participant pursuant to 7.5 above.

7.8 For any period mutually agreed upon that a Participant does not schedule according to Sec. 7.5 its full available Capacity Entitlement, the other Participant may schedule for its account Firm Power and Energy* from such unscheduled capacity, provided that:

(i) The Participant that did not schedule its full available capacity expressly in writing or by such other means as may be agreed upon, authorizes such scheduling for the entire agreed period.

(ii) At the sole option of the Participant giving up a portion of its Capacity Entitlement, that Participant may choose whose fuel will be used in generating that portion of its capacity being used by the other Participant. If the Participant taking the unscheduled capacity uses the other Participant's fuel, then the Participant giving up a portion of its capacity will be reimbursed for the cost of the fuel used by the Participant taking that capacity.

(iii) The Participant taking the unscheduled capacity credits the account of the non-taking Participant on a monthly basis or as otherwise agreed upon, for the amount of operation and maintenance expenses, excluding fuel, corresponding to the MWH

*except during periods of generation loss or other capacity limitations in which Firm Power and Energy schedules are subject to reduction according to 7.8 (iv) herein.

amount of the unscheduled capacity taken. Said credit for operation and maintenance expenses shall be determined by multiplying the annual average cost per megawatthour generated by the plant by the number of megawatthours of the unscheduled capacity taken from the plant for the billing period. The Participant taking unscheduled capacity shall also pay for the same billing periods capitalization costs applicable to the MW amount taken from the other's Entitlement. The capitalization costs for each billing period shall be computed by: the product of the non-taking Participant's embedded cost (revised quarterly) per megawatt of its FPP Entitlement, the capitalization factor (revised quarterly), reflected on the non-taking Participant's books for its FPP Entitlement, and the peak number of megawatts of the unscheduled capacity used during billing period.

(iv) In the event that one or both units or any essential component of the transmission system develop capacity limitations, then a "floating entitlement" shall come into effect in which the reduced capacity is shared equally by each Participant. In such circumstances, each Participant is entitled to receive 50 percent of the reduced plant capacity, and the Participant that had not scheduled its full Capacity Entitlement, shall have the right to reclaim as much of its reduced

Entitlement as is required to meet, or partially meet, its schedule according to Sec. 7.5 herein. Any remaining unscheduled capacity may still be used by the other Participant according to the rules herein.

7.9 For any period mutually agreed upon that a Participant does not schedule according to Sec. 7.5 its full available Capacity Entitlement, the other Participant may schedule for its own use such unscheduled capacity on a non-firm, interruptible basis under the same conditions of 7.8 (i) and 7.8 (ii). The provisions of 7.8 (iii) shall not apply. The Participant giving up a portion of its Entitlement may recall part or all of that Entitlement at any time."

III.

Section 19, "Fuel Cost Allocation," in the 1974 Participant Agreement is amended by amending Sections 19.2, 19.3 and 19.4 to read as follows:

"19.2 In the event of more than one Generating Unit, it shall be the responsibility of the Project Manager to assure that the coal moving to the bunkers of each Unit shall be weighed and sampled separately. In the case of coal provided under joint contracts with all Participants, the Project Manager shall bill each Participant upon delivery based on the proportion of each Participant's respective interest in the coal contract under which the coal is delivered. In the case of coal purchased by any Participant individually, the Project Manager shall bill that Participant for the full cost at delivery.

19.3 The Project Manager shall keep separate records of the coal inventories for each coal contract for each Participant. This record shall include the deliveries and the amount of coal burned by each Participant in meeting each Participant's schedule. The Project Manager shall ensure that each Participant uses only coal from that Participant's own inventory, except for generation pursuant to Sections 7.8 (ii) and the similar provision in Sec. 7.9 where the Participants may otherwise agree to use the other Participant's fuel.

19.4 The costs of ash disposal chargeable to FPC Account 501 shall be apportioned to the Participant in the ratio that each Participant's monthly Net Energy Generation scheduled from such Unit bears to the total monthly Net Energy Generation scheduled from such Unit."

Except as expressly hereinabove amended, all provisions of the 1974 Participant Agreement as heretofore amended are ratified and reconfirmed.

IN WITNESS WHEREOF, the parties have caused this amendment to be executed to be effective as of the 3rd day of February, 1981.

CITY OF AUSTIN

By: [signature]
Deputy City Manager

ATTEST:
[signature: Grace Monroe]
City Clerk

LOWER COLORADO RIVER AUTHORITY

By: [signature]
General Manager

OK
[initials]

ATTEST:
ass't [signature]
Secretary

1984 Amendment

AMENDMENT TO FAYETTE POWER PROJECT
PARTICIPATION AGREEMENT

Whereas, the City of Austin, Texas ("Austin"), a municipal corporation chartered under the Constitution and the laws of the State of Texas, and the Lower Colorado River Authority ("Authority"), a river authority incorporated under the laws of the State of Texas, previously have entered into the Fayette Power Project Participation Agreement dated the 19th day of September 1974 and as since amended (Participation Agreement), and

Whereas, Austin and the Authority desire to amend certain provisions of the Participation Agreement,

Now, therefore, in consideration of the mutual promises contained herein, Austin and the Authority hereby amend the Participation Agreement as follows:

1. Exhibit A entitled "Common Station Facilities" is hereby deleted Section 4.7 - "Common Station Facilities" is hereby deleted and in its stead is inserted the following as a new section 4.7:

> 4.7 - COMMON PROJECT SITE FACILITIES: Those components of the Project that are used in common by all Generating Units at the Plant Site. The question whether any real property or improvement thereto, or any personal property, machinery or equipment is a Common Project Site Facility shall be determined with reference to the operation, rather than the construction of the Generating Units. Without limiting the generality of the foregoing, the Plant Site, the cooling lake (or lakes), dam and spillway, and the river pumping

plant and pipeline, together with any additions or enlargements to the above, shall always be considered to be Common Project Site Facilities.

2. Section 4.8 - "CONSTRUCTION WORK" is hereby amended to read as follows:

4.8 - CONSTRUCTION WORK: All environmental impact studies, site and evaluation, acquisition of the Plant Site, engineering, design, construction, contract preparation, supervision, expediting, inspection, accounting, testing and start-up for Generating Units, Generating Units Common Facilities and Common Project Site Facilities up to the time of firm operation and the decommissioning, dismantling, removal and final disposition of all components of the Project, including, but not by way of limitation, all related engineering, design, contract preparations, purchasing, supervision, expediting, inspection, accounting, testing, management and protection.

3. Section 4.14 - "Generating Unit" is hereby amended to to read as follows:

4.14 - GENERATING UNIT: An electric generating unit, including the components thereof (steam supply system, turbine, and generator including step-up transformers and other associated equipment), located on the Plant Site. A Generating Unit does not include Common Project Site Facilities or Generating Units Common Facilities but does include that portion of the real estate encompassed within the boundaries of the Plant Site on which the Generating Unit sits. In addition, a Generating Unit includes all associated property and equipment used solely in conjunction with that electric generating unit.

4. There shall be inserted a new Section 4.15 to read as follows:

4.15 - GENERATING UNITS COMMON FACILITIES: Those components of the Project that are for the common use of two or more, but less than all Generating Units consisting of, but not limited to, for example, railroad loops, coal dumpers, coal handling facilities, ash handling facilities, ash disposal facilities, ash ponds, coal piles, switchyards and storage buildings and the land associated therewith.

Ownership of Generating Units Common Facilities shall be in the same proportion as ownership of the Generating Units to which the components are common.

5. Sections 4.15, 4.16, 4.17, 4.18, 4.19 will be renumbered and Section 4.20 will be deleted in its entirety. The new Section Numbers and their headings are as follows:

4.16 - MANAGEMENT COMMITTEE
4.17 - MINIMUM NET GENERATION
4.18 - NET EFFECTIVE GENERATING CAPABILITY
4.19 - NET ENERGY GENERATION
4.20 - PARTICIPANT

6. Section 5.1 is hereby deleted and the following paragraph 5.1 is inserted in its stead. In addition, new paragraphs 5.2, 5.3 and 5.4 are added, as follows:

5.1 - Regardless of the Participants' respective expenditures for the construction and operation of the Plant Site and the Common Project Site Facilities, each Participant shall own an undivided fifty percent (50%) interest in the Plant Site and the Common Project Site Facilities as a tenant in common with the other Participant. Except as otherwise provided in this Section 5, the Participants shall not reimburse each other with respect to construction expenditures for Common Project Site Facilities.

5.2 - Either Participant may propose Capital Additions and Capital Betterments to the Common Project Site Facilities not associated with the construction of any particular Generating Unit. Upon approval of the proposed project and its construction budget by the Management Committee, the Project Manager shall undertake the construction of the proposed Capital Additions or Capital Betterments to the Common Project Site Facilities in accordance with the general procedures established for construction pursuant to this Agreement. In the absence of an agreement between themselves to the contrary, the Participants shall pay for the Capital Betterments and Capital Additions in the same proportion that each Participant's aggregate Generation Entitlement Share in each Generating Unit then in commercial operation bears to the sum of the nameplate ratings of each such Generating Unit.

5.3 - Either Participant may propose Capital Additions and Capital Betterments to the Common Project Site Facilities which, though of use to the operation or construction of all Generating Units, are required by the construction or operation of one or more, but less than all generating units in existence or under construction. Upon approval of the proposed project and its construction budget by the Management Committee, the Project Manager shall undertake the construction of the proposed Capital Additions or Capital Betterments to the Common Project Site Facilities in accordance with the general procedures established for construction pursuant to this Agreement. In the absence of an agreement between themselves to the contrary, the Participants shall pay for the project in the same proportion that each Participant's aggregate Generation Entitlement Share in each Generating Unit whose operation or construction requires the construction of the Capital Additions or Capital Betterments bears to the sum of the nameplate ratings of all such Generation Units.

5.4 - Notwithstanding any other provision of this Agreement to the contrary, the Project cooling reservoirs (Cedar Creek Reservoir and the proposed Baylor Creek Reservoir) shall always be characterized as Common Project Site Facilities. If and when the Management Committee decides that the construction of an Additional Generating Unit will require the construction and use of Baylor Creek Reservoir for proper cooling of the existing or proposed Generating Units, the construction of Baylor Creek Reservoir and any associated water use facilities shall be paid for by the Participants in proportion to their respective ownership interests in the Additional Generating Unit which occasioned the construction of Baylor Creek Reservoir. Should any subsequent Additional Generating Units cooled from Baylor Creek Reservoir be built, the Participants shall, within 90 days after the date of commercial operation of any such Additional Generating Unit, make such payments among themselves as may be required so that each Participant's investment (including reimbursements here required) in the Baylor Creek Reservoir and associated water use facilities bears the same proportion to the total of all construction costs for such reservoir and facilities as the sum of each Participant's Generation Entitlement Share in each Generating Unit cooled from Baylor Creek Reservoir bears to the sum of the nameplate ratings of all Generating Units cooled from Baylor Creek Reservoir.

7. Section 6 is hereby amended to read as follows:

6. ADDITION OF GENERATING UNITS:

6.1 - A Participant may propose the construction of an Additional Generating Unit by written notice to the other Participant setting forth:

6.1.1 A general description of the proposed Additional Generating Unit and of proposed Capital Additions and Capital Betterments to the existing Common Project Site Facilities and Generating Units Common Facilities, describing the design features of the Unit, the designed gross and net capacity, and the proposed fuel and fuel source, identifying all Common Project Site Facilities, Generating Units Common Facilities and all associated facilities of existing Generating Units proposed for use in connection with the proposed Addicional Generating Unit or with respect to which Capital Additions or Capital Betterments are proposed.

6.1.2 A plat of the Plant Site depicting the location of the proposed Additional Generating Unit.

6.1.3 An estimate of the respective costs of the proposed Additional Generating Unit, Capital Additions and Capital Betterments, all in reasonable detail.

6.2 - Within forty-five (45) days after service of the written notice given pursuant to Section 6.1 hereof, the Project Manager shall furnish to each Participant a statement, in reasonable detail, of all actual costs (without depreciation) of all Construction Work attributable to the Generating Units Common Facilities and to facilities associated with existing Generating Units identified in Section 6.1.1 hereof, as shown on the books of such Project Manager.

6.3 - The non-proposing Participant may elect to participate in the proposed Additional Generating Unit, Capital Additions and Capital Betterments up to a maximum 50% ownership share by means of a written election served upon the proposing Participant within three (3) months after service of the written notice given pursuant to Section 6.1 hereof. Failure of a Participant to exercise said election as provided in this Section 6.3 within the time period specified shall be conclusively deemed to be an election not to participate.

6.4 - Should the non-proposing Participant elect to participate in the proposed Additional Generating Unit, the proposed Additional Generating Unit, Capital Additions and Capital Betterments shall be constructed, operated and maintained in accordance with the provisions of this Participation Agreement and the Project Agreements, and shall be owned by the Participants (subject to adjustments as provided herein) in the proportion established in the non-proposing Participant's notice of election given pursuant to paragraph 6.3 above, and shall become a part of the Project.

6.5 - Should the non-proposing Participant elect not to participate in the proposed Additional Generating Unit, the proposing Participant shall construct, and shall pay all costs of Construction Work, and the Project Manager shall operate and maintain the Additional Generating Unit, Capital Additions and Capital Betterments proposed pursuant to Section 6.1 hereof. The Additional Generating Unit shall be owned by the proposing Participant, and shall become part of the Project.

6.6 - Within two months after the proposing Participant has determined the actual costs of the Capital Additions and Capital Betterments to the previously existing Common Project Site Facilities, Generating Units Common Facilities, and facilities associated with previously existing Generating Units undertaken in conjunction with the Additional Generating Unit, the Project Manager shall furnish to each Participant a statement showing the following:

6.6.1 each item of all actual costs of all Generating Units Common Facilities incurred to date. This list shall include each item of all actual costs of Common Project Site Facilities and facilities previously associated solely with an individual Generating Unit which, with the operation of the Additional Generating Unit, have become items of Generating Units Common Facilities.

6.6.2 the total of all expenditures for Generating Units Common Facilities identified above incurred by each Participant to date;

6.6.3 a proration among the Participants of the costs of each item of Generating Units Common Facilities identified above according to their respective ownership interests in the Generating Units to which the items of Generating Units Common Facilities are common;

6.6.4 a comparison of each Participant's expenditures for Generating Units Common Facilities identified in 6.6.2 above with the sum of each Participant's prorated costs identified in 6.6.3 above.

If the Participants' actual expenditures and prorated costs of Generating Units Common Facilities are not equal, the Participant whose expenditures are less than its prorated cost shall, within 30 days of receipt of the information called for in this paragraph, pay to the other Participant the difference between its expenditures and its prorated costs. For the purpose of any future calculations to be made with reference to the Participants' expenditures for Generating Units Common Facltiies, the Participants' actual expenditures shall be debited or credited for the amount of any payment made pursuant to this paragraph.

8. Section 9.4 is hereby amended to read as follows:

9.4 - All matters coming under the authority of the Management Committee shall be decided by majority vote of the members of the Committee with each member having equal voting rights; provided, however, that representatives of a Participant with no ownership interest in a particular Generating Unit shall not vote on matters relating solely to the construction or operation of that Generating Unit, and not materially affecting other Generating Units. All decisions reached by the Management Committee on matters concerning the Project and properly before the Management Committee for decision pursuant to the terms of this Participation Agreement or the Project Agreements shall be binding upon all Participants.

9. Section 10.2 is hereby amended to read as follows:

10.2 - Austin hereby appoints the Project Manager as its agent with respect to those Generating Units and Generating Units Common Facilities in which Austin has an ownership interest and for Common Project Site Facilities. The Project Manager shall undertake as Austin's agent for the Generating Units and Generating Units Common Facilities in which Austin has an ownership interest and for Common Project Site Facilities and as principal on its own behalf, the responsibility for the performance and completion of Construction Work and Station Work required by this Participation Agreement.

10. A new Section 10.4 is added, as follows:

10.4 - The books of account and the financial records of the Project Manager and the affairs of the Project as a whole shall be kept and conducted on a fiscal year ending June 30 of each year.

11. Section 12.1.6 is hereby amended to read as follows:

12.1.6 All costs of Construction Insurance, all costs of any loss, damage or liability arising out of or caused by Construction Work which are not satisfied under the coverage of Construction Insurance, and the expenses incurred in settlement of injury and damage claims, including the costs of labor and related supplies and expenses incurred in injury and damage activities (all as referred to in FPC Account 925), because of any claim arising out of or attributable to the past or future performance or nonperformance of Construction Work, including but not limited to any claim resulting from death or injury to persons or damage to property.

12. Section 14.2 is hereby amended to read as follows:

14.2 - The expenses described in paragraph 14.1.1 above relating to Common Project Site Facilities shall be borne by the Participants in the same proportion as the sum of each Participant's Generation Entitlement Share in each Generating Unit bears to the sum of the nameplate rated capacity of all Generating Units. Those expenses associated with the operation of the Generating Units and the Generating Units Common Facilities shall be apportioned to each of the Generating Units and allocated among the Participants according to their respective ownership interests in the Generating Unit to which the cost is attributed, to allow Austin and LCRA, as near as practical and in keeping with sound utility practices, to pay for their proper portion of such costs and expenses.

13. Section 14 3 is hereby amended to read as follows:

14.3 - Expenses described in Section 14.1.2 hereof shall be charged directly to each Generating Unit, Generating Units Common Facilities or the Common Project Site Facilities, as the case may be. The expenses so charged directly to the Common Project Site Facilities shall be allocated to each Generating Unit in the proportion that each Unit's nameplate rated capacity bears to the sum of all Generating Units nameplate rated capacities, so that, in keeping with sound utility practices, the Participants may pay for their proper proportion of such costs and expenses.

14. Sections 16.3 and 16.4 are amended to read as follows:

16.3 - The Management Committee shall establish a minimum amount for the Operating Account so that the Project Manager will have Operating Funds to pay for expenditures or obligations incurred by the Project Manager pursuant to this Participation Agreement. Such minimum amount may be revised by the Management Committee at any time. The original minimum amount and any increase therein shall be allocated among the Participants as described in Section 14.2 and shall be due and payable within fifteen (15) business days following notification of the establishment of the Operating Account or the date on which any increase in such minimum amount shall become effective. In the event the Management Committee authorizes a decrease in such minimum amount, then each Participant shall receive a credit which shall be equal to its proportionate share of the minimum amount.

16.4 - Each Participant shall advance Operating Funds to the Operating Account on the basis of bills it receives from the Project Manager which reflect such Participant's share of costs and expenses determined in accordance with this Participation Agreement as follows:

16.4.1 Costs incurred in the acquisition of fuel (excluding separately billed transportation charges) and Project Insurance shall be billed in a Request for Funds. Such a Request shall be based on invoices or statements from vendors and shall be due prior to the date of payment on invoices.

16.4.2 The Management Committee shall set an amount to be advanced weekly to cover invoices for fuel transportation charges. The advance for the first week of the month shall include an adjustment for the difference between amounts advanced and actual transportation costs incurred in the prior month.

16.4.3 All other costs and expenses incurred in the operation and maintenance of the Common Project Site Facilities, Generating Units Common Facilities and Generating Units, including costs recorded in FERC accounts 107 and 108, shall be billed to the Participants after the close of the books for the month.

16.4.4 To the extent that the minimum amount described in Section 16.3 will not cover monthly costs and expenses billed pursuant to Section 16.4.3, the Project Manager may request payment of additional funds based on actual invoices or estimated amounts. Such an advance shall be due within five business days from the date of submittal of the request and shall be credited to the Participants when calculating costs and expenses billed pursuant to Section 16.4.3.

15. Section 18.1 is hereby amended to read as follows:

18.1 - The Project Manager shall solicit and obtain bids and contract proposals for a proposed supply of fuel for Generating Units in which both LCRA and Austin shall have an interest and shall submit such bids and proposals to the Management Committee for review and approval. With respect to additional Generating Units, such proposed fuel supply arrangements shall be consistent with the fuel and fuel source identified in the notice required by Section 6.1.1. Any fuel supply contracts approved by the Management Committee shall be then submitted to the Participants. Both Participants shall execute fuel contracts pertaining to Generating Units in which LCRA and Austin have a joint participation.

16. Section 19.1 is hereby amended to read as follows:

19.1 - The cost of purchasing a reserve supply of fuel shall be apportioned to the Participants to allow Austin and LCRA, as near as practical and in keeping with sound utility practices, to pay for their proper proportion of such costs and expenses.

17. Section 19.2 is hereby amended to read as follows:

19.2 - In the event of more than one coal-fired Generating Unit, it shall be the responsibility of the Project Manager to assure that the coal moving to the bunkers of each coal-fired Unit shall be weighed and sampled separately. The cost of coal burned in each respective coal-fired unit in each calendar month as reflected by invoices submitted by the fuel suppliers and related costs chargeable to FPC Account 501 shall be in accord with the quantity of coal weighed and sampled during the movement into the bunkers of the respective Units.

18. Section 24 is hereby amended to read as follows:

24.1 - If a Generating Unit or Generating Units Common Facilities should be damaged or destroyed to the extent that the estimated cost of repairs, replacement or reconstruction is not more than one hundred percent (100%) of the aggregate amount of the proceeds from property damage insurance carried and covering the cost of the repairs, replacement or reconstruction of such Generating Unit or Generating Units Common Facilities, the Participants, unless otherwise unanimously agreed, shall repair, replace or reconstruct such Generating Unit or Generating Units Common Facilities to substantially the same general character or use as the original. The Participants shall share the cost of such repairs, replacements or reconstruction in proportion to their respective ownership interest in the Generating Unit or Generating Units Common Facilities so destroyed.

24.2 - If a Generating or Generating Units Common Facilities should be damaged or destroyed to the extent that the estimated cost of repairs, replacement or reconstruction is more than one hundred percent (100%) of the aggregate amount of the proceeds from property damage insurance carried and covering the cost of the repairs, replacement or reconstruction of such Generating Unit or Generating Units Common Facilities, the Participants shall, upon agreement, repair, replace or reconstruct such Generating Unit or Generating Units Common Facilities to substantially the same general character or use as the original; provided, however, that should the Participants not agree to repair, replace or reconstruct such Generating Unit or Generating Units Common Facilities, then any Participant who does not agree to repair, replace or reconstruct shall sell its interest in such Generating Unit or Generating Units Common Facilities to the Participant desiring to repair, replace or reconstruct such Generating Unit or Generating Units Common Facilities for a price equal to the selling Participant's proportionate interest in the salvage value of such Generating Unit plus such Participiant's proportionate cost, less depreciation at the maximum straight line rates then applicable to like properties under the Federal income tax law, in the interest in the Generating Units Common Facilities so sold.

24.3 - If any of the Common Project Site Facilities should be destroyed, the Participants shall, unless otherwise agreed, repair or reconstruct same to substantially the same character or use as the original. The Participants shall share the costs of such repair or reconstruction in proportion to the ownership of the Project as set forth in Section 5 above.

19. Section 26.1 is amended to read as follows:

26.1 - Each Participant shall protect, indemnify, and hold the other Participant, and its directors, officers and employees, free and harmless from Construction Work Liability arising out of construction of an Additional Generating Unit in which the other Participant has no ownership interest. Except as provided in the previous sentence, Participants shall have no remedies against the other Participant for tortious conduct arising out of the ownership of the Project, or any portion thereof, or out of Construction Work or Station Work except when the claim res : from Willful Action.

20. stin and the Authority expressly agree that any term, c :ion, covenant or agreement set forth in this 1984 amendmer ıall control over any term, condition or covenant in the Par pation Agreement that may be in conflict.

IN W ESS WHEREOF, the parties hereto have caused this amendmen o the Participation Agreement to be executed as of the 30 day of March, 1984.

CITY OF AUSTIN

Attest:

James E. Aldridge
City Cl

By: Jorge Carrasco
Jorge Carrasco
Acting City Manager

LOWER COLORADO RIVER AUTHORITY

Attest
Hogan
Secretary

By Elof Soderberg
Elof Soderberg
General Manager

RELEASE AGREEMENT BETWEEN CITY OF AUSTIN AND LOWER COLORADO RIVER AUTHORITY CONCERNING PARTICIPATION IN FAYETTE POWER PROJECT UNITS 3 AND 4

Whereas, the City of Austin, Texas (Austin), a municipal corporation chartered under the constitution and laws of the State of Texas, and the Lower Colorado River Authority (LCRA), a river authority incorporated under the laws of the State of Texas, previously have entered into the Fayette Power Project Participation Agreement dated the 19th day of September, 1974 and as since amended (Participation Agreement) and,

Whereas, Austin and LCRA on January 31, 1984 entered into a Memorandum of Understanding concerning the Fayette Power Project (Fayette) and,

Whereas, Austin has heretofore paid the LCRA $2,775,622.44 in payments for Fayette Unit 3 and,

Whereas, Austin desires to relinquish any rights it may possess under the Participation Agreement concerning participation in Fayette Units 3 and 4 and,

Whereas, the LCRA desires to repay to Austin the sum of $2,775,622.44 previous paid to LCRA, Now, therefore, Austin and LCRA mutually agree as follows:

1. Austin does hereby release, discharge and relinquish any and all rights it may have now or in the future under said Participation Agreement for participation in Fayette Units 3 and 4 and further release the Lower Colorado River Authority from any duty, obligation or notice requirement under said Participation Agreement concerning Fayette Units 3 and 4.

2. The LCRA does hereby release, discharge and relinquish any and all claims, disputes or actions it may have against Austin now or in the future for any payment or any other duty or obligation for any Particiation and ownership in Fayette Unit 3 and 4 arising out of, or in connection with said Participation Agreeent.

3. In consideration of the foregoing, Austin does hereby agree:

a. To Authorize LCRA to utilize Powell Bend lignite in Fayette Units 1 and 2 for the LCRA account provided that the utilization of Powell Bend lignite does not result in exceeding any regulatory requirements or materially affect performance of Fayette

Units 1 and 2 or require Austin to reduce its western coal commitments below Austin's minimum take levels.

b. To provide funding for Austin's pro-rata share of the conversion of Fayette Units 1 and 2 to dry fly ash.

c. To reserve to LCRA that certain portion of land at the Project Site designated for Unit 4 on Exhibit "A" attached hereto; provided, however, that Unit 4 is fueled by Cummings Creek lignite, that Unit 4 utilizes Generating Units Common Facilities with Unit 3, that Unit 4 utilizes the same basic design concepts as Unit 3 and that Unit 4 is the same nominal size as Unit 3.

4. In consideration of the foregoing, LCRA does hereby agree:

a. To sell Austin Powell Bend lignite for Fayette Units 1 and 2 at LCRA's cost, including reasonable compensation for LCRA's risk.

b. To pay Austin the sum of $2,775,622.44, in good and legal tender or to credit Austin's Fayette account for that amount, at Austin's option, said payment to reflect the total refund due Austin for progress payments made toward Fayette Unit No. 3.

In witness whereof the parties hereto have caused this release to be executed as of the 30th day of March, 1984.

City of Austin

By: Jorge Carrasco
Jorge Carrasco
Acting City Manager

Attest: James E. Aldridge
City Clerk

Lower Colorado River Authority

By: Elof Soderberg
Elof Soderberg
General Manager

Attest: Jess Hogan
asst. Secretary

Authority Original

STATE OF TEXAS]
COUNTY OF TRAVIS]

Minute 8212

1975 JOINT TRANSMISSION AGREEMENT BETWEEN
LOWER COLORADO RIVER AUTHORITY AND
CITY OF AUSTIN

THIS AGREEMENT, hereinafter referred to as the "1975 Agreement", between the Lower Colorado River Authority, hereinafter called "Authority", acting pursuant to resolutions of its Board of Directors, and the City of Austin, a municipal corporation, situated in Travis County, Texas, acting pursuant to actions of its City Council, hereinafter called "City";

W I T N E S S E T H:

I.

CONSIDERATION

City desires to construct certain facilities on certain Authority right-of-way, and Authority agrees to allow City to construct said facilities, and to cooperate with City in said construction, as hereinafter set forth. Consideration for this agreement consists of the mutual agreements contained herein and the mutual benefits to accrue to the parties hereto from said agreements.

II.

PRIOR AGREEMENTS

City and Authority, for their mutual benefits, have entered into several mutual agreements prior to this 1975 Agreement, including an agreement entitled "1966 Agreement Between Lower Colorado River Authority and City of Austin", dated December 15, 1966, executed for the City and Authority, respectively, by W. T. Williams, Jr., City Manager, and Sim Gideon, General Manager, which said agreement is referred to hereinafter as "1966 Agreement", and which provided for, among other things, the joint use by the said parties of existing rights-of-way.

The portions of the 1966 Agreement which are most pertinent to this 1975 Agreement are as follows:

(1) Article XI, Subsection E-3, of said 1966 Agreement, which contemplates mutual agreement to construct additional projects.

(2) Paragraph F of said Article XI, which provides for specific authorization by both parties of said additional projects after detail design and cost estimates have been made and prior to construction.

(3) Paragraph G of said Article XI, which provides a method of sharing cost on transmission structures which are to be jointly used.

III.

1975 AGREEMENT TERMS

A. City agrees to construct as soon as City deems it practicable, and bear all right-of-way costs and damages, if any, resulting from such construction, at its own cost, the following described transmission structures on the existing Authority's right-of-way from HiCross Substation in Travis County, Texas, to a junction point, 6.96 miles, more or less, generally east of said substation, and on a right-of-way provided and paid for by the City of Austin from said junction point 11.16 miles, more or less, to the Decker Power Plant, as indicated on the map attached hereto, and incorporated herein, marked Exhibit "A":

(1) On that portion of said right-of-way from HiCross Substation to the above described junction point (6.96 miles generally east of HiCross Substation), excluding that portion described in paragraph (2) below, double circuit structures shall be built and said double circuit structures shall be offset on the right-of-way to provide space thereon for future construction of another line of transmission structures, and said structures shall accommodate 795,000 CMACSR bundled conductor.

(2) On that portion of said right-of-way which is south of Bergstrom Air Force Base and within the height restricted runway approach, provisions will be made for four circuit low profile structures, with an initial installation of only that part required for two circuits. The City will provide and pay for the additional 75 feet wide by 5,130 feet long right-of-way required to accommodate the low profile structures. Said structures shall accommodate 795,000 CMACSR bundled conductor.

(3) On that portion of said right-of-way from the above described junction point to Decker Plant, double circuit structures shall be built and said double circuit structures shall be offset on the right-of-way to provide space theron for future construction of another line of transmission structures, and said structures shall accommodate 795,000 CMACSR bundled conductor.

B. The above described structures shall be used as follows:

(1) The double circuit structures which will be located on the right-of-way provided and paid for by the Authority shall provide one circuit each for City and Authority.

(2) The double circuit structures which will be located on the right-of-way provided and paid for by the City shall provide one circuit for City with provisions for a future circuit for Authority.

IV.

PAYMENT OF COSTS

A. The cost of installation of the structures described under Section III shall be borne by City, and City shall provide Authority upon the completion of the construction of such structures a detailed and complete breakdown of the costs incurred during such construction. City after coordination with Authority shall remove Authoritie's existing structures, and transfer the existing conductors to the new structures, and upon completion of said removal and transfer, City shall reimburse Authority for any cost incurred by the Authority.

B. Should Authority, subsequent to the above described construction, rebuild or replace its existing circuit provided for in Section III, B (1) to increase its capacity, Authority shall, at the time such rebuilding or replacing is completed, pay City one-half of the installed cost of the double circuit structures described in Section III A(1) and A(2).

C. Should Authority, subsequent to the above described construction, build the circuit provided for in Section III, B(2), Authority shall at the time such circuit is completed, pay City one-half of the installed costs of the double circuit structures described in Section III, A(3).

V.

RATIFICATION OF PRIOR
AGREEMENTS

Except as herein expressly modified or changed, each and all of the provisions of all earlier agreements between the City and the Authority, including said 1966 Agreement, are in all things ratified, affirmed and approved.

IN WITNESS WHEREOF the parties hereto have caused this 1975 Agreement to be executed by their duly authorized officers this 4th day of April, 1975.

CITY OF AUSTIN

BY: ______________________
City Manager

ATTEST:

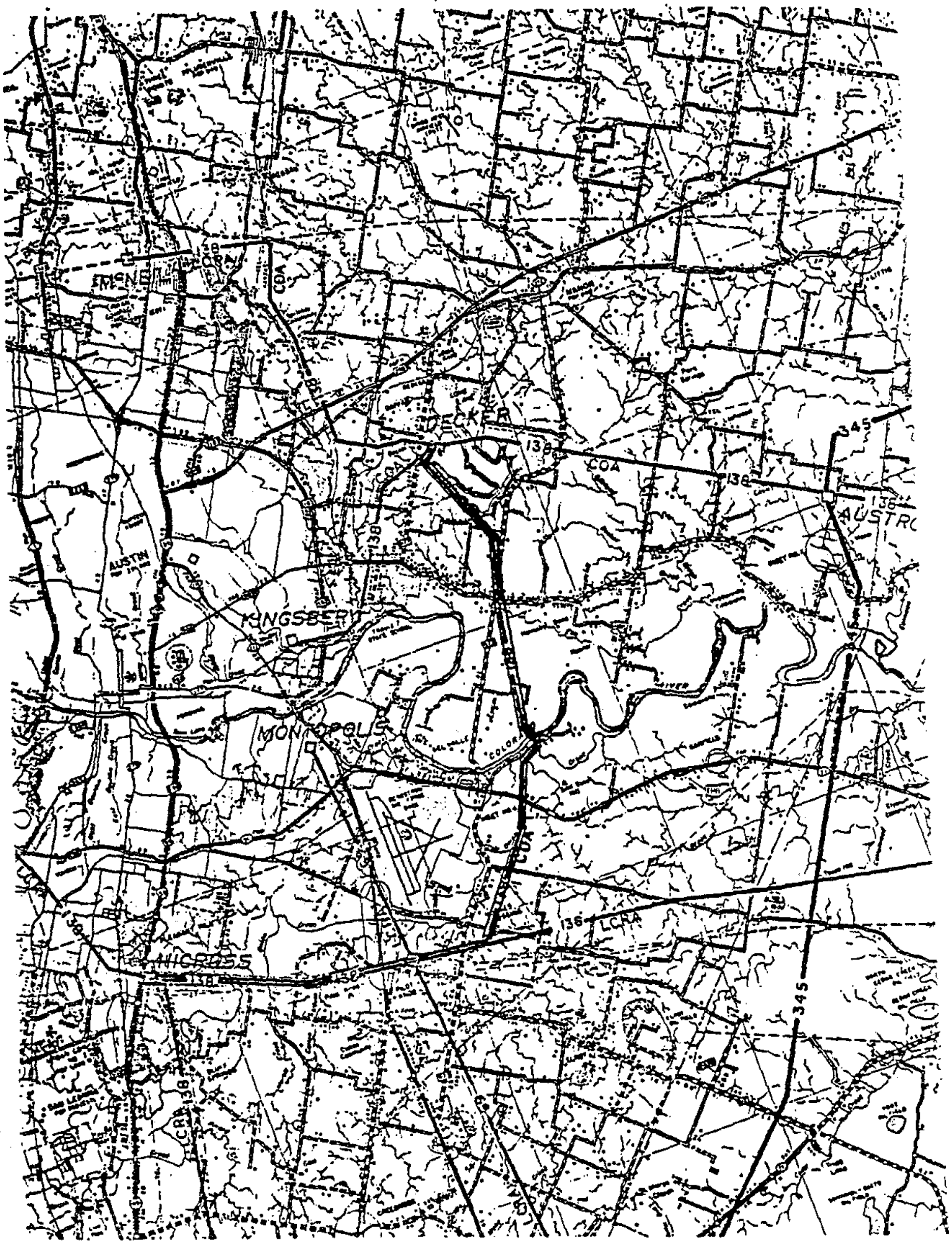
Grace Monroe
City Clerk

LOWER COLORADO RIVER AUTHORITY

BY: ______________________
General Manager

ATTEST:

____
Secretary



CITY OF AUSTIN - L.C.R.A. AGREEMENT

EXHIBIT "A"

ROUTE OF 138 KV TRANSMISSION LINE
DECKER POWER PLANT TO HICROSS SUBSTATION

═══ L.C.R.A Right of Way ═══ City of Austin Right of Way

Approved 7/24/77 Minute # 9082

RECEIVED
APR 18 1977
Planning Dept.

THE FAYETTE POWER PROJECT

TRANSMISSION AGREEMENT

FEB 17 1977

INDEX

THE FAYETTE POWER PROJECT
TRANSMISSION AGREEMENT

1. PARTIES: The parties to this Agreement are: CITY OF AUSTIN, hereinafter referred to as "Austin," and LOWER COLORADO RIVER AUTHORITY, hereinafter referred to as "LCRA."

2. RECITALS:

2.1 The parties have heretofore entered into a Participation Agreement dated September 19, 1974, (the Participation Agreement) providing for the construction, operation, and maintenance of jointly owned and operated electric generation facilities to be known as the Fayette Power Project (the Project), and each will be entitled to equal shares of the power and energy available at the Project Switchyard.

2.2 A coordinated transmission system using both jointly owned transmission facilities and facilities solely owned by each party will provide the most efficient and economical means of transferring the generation entitlement of the parties from the Project to their respective distribution systems and will assist Austin in the transmission of power and energy from the South Texas Nuclear Project to its Electric System.

2.3 The purpose of this agreement is to provide for the timely acquisition, construction, installation, maintenance and operation of such a coordinated transmission system.

3. AGREEMENT: In consideration of the mutual benefits and covenants herein, the parties agree as hereinafter set forth.

4. GENERAL PRINCIPLES AND DEFINITIONS:

4.1 Exhibit "A" attached hereto is a schematic diagram showing transmission facilities and circuitry contemplated by this Agreement.

4.2 Exhibit "B" attached hereto is a schematic diagram showing the communication and control facilities contemplated by this Agreement.

4.3 In all instances when one party hereto has the responsibility of designing, planning, procuring, installing or constructing any facility hereunder and the facility will be jointly owned, the applicable provisions of the Participation Agreement shall be followed as though the performing party were the Project Manager and the facility would be a Project facility.

4.4 If economy or efficiency will be enhanced, the Management Committee of the Project may designate either party to act as agent for the other in acquiring specified equipment or services for any facility contemplated by this agreement, regardless of the final ownership and operating arrangement.

4.5 The scope, quality and frequency of maintenance of all jointly owned equipment and solely owned equipment located on or at jointly owned facilities or on or at solely owned facilities of the other party shall be determined by the Management Committee under applicable provisions of the Participation Agreement.

4.6 This Agreement relates to the Project and shall be considered a Project Agreement with the following specific understandings and conditions:

4.6.1 Except for that jointly owned property covered by this agreement and designated as Project Property, none of the properties, facilities or equipment contemplated by this Agreement, whether solely or jointly owned by the parties, shall be considered part of the Project as such is defined and described in paragraph 4.26 of the Participation Agreement.

4.6.2 Notwithstanding the provisions of 4.6.1 above, the Participation Agreement, where it is not inconsistent with the provisions of this Transmission Agreement, is incorporated herein, made a part hereof and shall bind LCRA and Austin with respect to their individual and collective rights, duties, and obligations in and to all of the jointly owned or maintained properties and facilities contemplated by this agreement.

4.6.3 The provisions for construction, installation and maintenance of equipment and facilities herein shall apply only to the equipment and facilities covered hereby and shall not be construed to cover any future additions by either party.

4.7 Termination of a transmission line includes circuit breakers; two (2) air disconnect switches per circuit breaker; bus from associated circuit breaker to the first contact point of the transmission line on the dead end structures; dead end structures; lightning arresters; wave trap; coupling capacitor potential device; line insulators and hardware; associated foundations and supporting structures; relaying and supervisory control; tie line telemetering when required.

4.8 The term "breaker" as used in this agreement means circuit interruption devices which have the effect of permitting or not permitting the flow of power and energy through the device including air switches which are connected to each individual breaker.

4.9 The term "joint interest breaker" as used in this Agreement means a breaker the operation of which by one party could affect the functional integrity of the other party's electric system.

4.10 The term "operational supervision of a breaker" means the capability of operating the breaker.

4.11 The term "use of house and tower" as used in this Agreement means that the user may install equipment, run cables, use available AC and DC power and use available 19" relay rack space if any exists. The extent of tower use is limited by design strength.

4.12 Common substation facilities include control house and fence; main bus; potential transformation of main bus voltage for relaying and metering; station service; 125 Volt DC control power; grounding grid; control conduit system.

4.13 The term "wheeling of power" for the purposes of this agreement means the transmission of power belonging to one party through the transmission system belonging to another.

5. CONSTRUCTION AND INSTALLATION OF FACILITIES

5.1 PROJECT SWITCHYARD EQUIPMENT

5.1.1 Description

5.1.1.1 all equipment necessary to connect the high voltage terminals of generating units 1 and 2 step-up transformers to the first contact point of incoming 345KV transmission lines from the Fayetteville, Austrop and Holman Substations on the switchyard dead end structure as shown on Exhibit A.

5.1.1.2 single side band power line carrier equipment and protective relaying for the transmission line to Holman Substation including line trap, coupling capacitor, line tuner, four-channel single side band power line carrier and one terminal of protective relaying.

See 5.1.3

5.1.1.3 multiplex and interface equipment for microwave communication between LCRA System Operations Control Center and Lytton Springs Substation, Holman Substation and Fayette Power Project.

5.1.1.4 All equipment necessary to establish a point of interconnection between the parties at this location.

5.1.2 Installation

5.1.2.1 The equipment described in 5.1.1.1, 5.1.1.3 and 5.1.1.4 shall be provided and installed by LCRA.

5.1.2.2 The equipment described in 5.1.1.2 shall be provided and installed by Austin.

5.1.3 Ownership

5.1.3.1 All equipment described in 5.1.1 shall be owned and paid for jointly by the parties and, (except the main microwave carrier system and its accessories which is owned and paid for solely by LCRA) shall be Project Property and part of the Project.

5.1.4 Maintenance: All switchyard equipment shall be maintained by LCRA at joint cost to the parties except the power line carrier, associated equipment and protective relaying for the line to Austrop Substation and the equipment described in 5.1.1.3 which shall be maintained by LCRA at its sole cost. The equipment described in 5.1.1.2 shall be maintained by Austin at its sole cost.

5.1.5 Breaker Operation: LCRA shall have sole control of the breakers terminating its 345 KV double circuit line to Fayetteville Substation and, as Project Manager, control of the breakers terminating Project generators 1 and 2 into the 345 KV buses. The breakers terminating the 345 KV lines to Austrop and Holman Substations shall be joint interest breakers under the operational supervision of LCRA.

5.2 TRANSMISSION CORRIDOR

5.2.1 Description: A transmission line right-of-way of sufficient width to accommodate two (2) 345 KV double circuit transmission structures from the Project Switchyard to LCRA's existing 138 KV transmission line from Winchester to Fayetteville a distance of approximately five (5) miles.

5.2.2 Acquisition and Ownership: This right-of-way shall be acquired by LCRA for the joint ownership of the parties and shall be used for the Project to Fayetteville and Project to Austrop transmission lines.

5.2.3 Maintenance: This right-of-way shall be maintained by LCRA for the joint account of both parties.

5.3 TRANSMISSION LINE TO AND SUBSTATION EQUIPMENT AT FAYETTEVILLE SUBSTATION

5.3.1 Description: A new 345 KV bundled 795 MCM, ACSR transmission line with double circuit structures from the Project Switchyard to LCRA's Fayetteville Substation a distance of approximately seven and one-half (7-1/2) miles to be constructed on the jointly owned transmission corridor and on new right-of-way to be acquired and owned by LCRA; the equipment necessary to terminate such transmission line at such substation and a 600 MVA 345/138 KV auto-transformer and associated equipment.

5.3.2 Construction, Installation, Ownership and Maintenance: The transmission line and all substation equipment shall be constructed, installed, operated and maintained by LCRA at its cost and owned by it.

5.3.3 Control of Substation Equipment: All substation equipment shall be under the sole control of LCRA.

5.4 TRANSMISSION LINE TO AND SUBSTATION EQUIPMENT AT AUSTROP SUBSTATION

5.4.1 Description:

5.4.1.1 A new single circuit 345 KV bundled 795 MCM, ACSR transmission line from the Project Switch-yard to the existing jointly owned Austrop Substation to be constructed on the jointly owned transmission corridor and on new right-of-way to be acquired and owned by Austin and which where practical will be parallel to and partially overlap existing LCRA right-of-way.

5.4.1.2 Equipment including power line carrier, associated equipment and protective relaying to terminate such transmission line on the Austrop Substation 345 KV bus according to plans furnished by Austin and approved by LCRA's Chief Engineer prior to construction.

5.4.2 Construction, Installation, and Ownership: The transmission line shall be constructed and all termination equipment shall be installed by Austin at its cost and be owned by it.

5.4.3 Breaker Operation: The breakers for this transmission line shall be joint interest breakers under the operational supervision of LCRA. Austin shall have the right to install supervisory control equipment for these breakers and in such event, the parties shall have joint operational supervision of them.

5.4.4 Maintenance: Austin shall maintain at its cost all the substation equipment except the power line carrier, associated equipment and protective relaying which shall be maintained by LCRA at its cost. Austin shall maintain at its own cost the transmission line and its right-of-way except as provided for under 5.2.3.

5.4.5 Additional Agreement of LCRA: LCRA consents to the use of the common substation facilities required for installation and operation of the termination equipment at Austrop Substation.

5.5 TRANSMISSION LINE TO HOLMAN SUBSTATION THENCE TO LYTTON SPRINGS SUBSTATION

5.5.1 Description: A new bundled 795 MCM, ACSR 345 KV transmission line with double circuit structures from the Project Switchyard to Holman Substation located approximately nine (9) miles south of the Project and from Holman Substation to Lytton Springs Substation, a distance of approximately fifty-five (55) miles. Only one circuit shall be installed initially.

5.5.2 Construction: The right-of-way for this line and the line itself shall be acquired and constructed by LCRA for the joint account of the parties.

5.5.3 Ownership: The structures and right-of-way shall be owned jointly by the parties and, until the installation of a second circuit, the initial circuit shall be jointly owned.

5.5.4 Maintenance: LCRA shall maintain the structures, conductors and right-of-way for the joint account of the parties.

5.6 SECOND CIRCUIT FROM THE PROJECT TO LYTTON SPRINGS SUBSTATION

Either party may elect to add a second 345 KV circuit to the transmission line structures from the Project to Lytton Springs including any necessary changes at Lytton Springs Substation at its own cost. This second circuit shall bypass Holman Substation. If Austin elects to add such second circuit, LCRA shall elect either (i) to take over and own the entire second circuit by paying Austin one-half (1/2) the actual direct materials and labor costs of the initial circuit excluding structures and right-of-way in which event Austin would own the initial circuit and remain one-half owner of the structures and right-of-way; or (ii) to take only a one-half (1/2) interest in the second circuit at no cost and give up its interest in the initial circuit and remain one-half owner of the structures and right-of-way. If LCRA elects to add the second circuit, Austin shall pay LCRA one-half (1/2) of the cost of the initial circuit specified above excluding structures and right-of-way and take over and own the initial circuit but have no further interest in the second circuit. In any event after the installation of the second circuit, LCRA would have no further interest in Holman Substation.

5.7 SOUTH TEXAS NUCLEAR PLANT TO HOLMAN SUBSTATION TRANSMISSION LINE

5.7.1 Description: A single circuit bundled 795 MCM ACSR 345 KV transmission line from the South Texas Nuclear Plant to Holman Substation.

5.7.2 Installation, Ownership and Maintenance: This transmission line including right-of-way shall be procured, installed, paid for, owned, maintained and under the control of Austin solely.

5.8 HOLMAN SUBSTATION

5.8.1 Description:

5.8.1.1 A new substation including site and all equipment and facilities required to terminate and connect the 345 KV transmission line from the Project to Lytton Springs Substation and the 345 KV transmission line from the South Texas Nuclear Plant.

5.8.1.2 Single side band power line carrier equipment and protective relaying at this substation for the transmission line from Project to Lytton Springs Substation including line traps, coupling capacitors, line tuners, four-channel, single side band power line carrier with base band repeaters and local drop and two terminals of protective relaying.

5.8.2 Construction, Installation and Ownership: Austin shall acquire the site for and shall construct the substation and install all equipment for its own account.

5.8.3 Breaker Operation: The breakers for the 345 KV line from the Project to Lytton Springs installed for the first circuit shall be joint interest breakers under the operational supervision of Austin until the second circuit which will bypass this substation is installed on such line; thereafter the breakers installed for the first circuit shall be under the sole control of Austin.

5.9 LYTTON SPRINGS SUBSTATION

5.9.1 Description:

5.9.1.1 A new substation to be located near the town of Lytton Springs on or near the right-of-way of LCRA's double circuit 345 KV transmission line between Austrop Substation and Zorn Substation, the purpose of which installation will be to terminate and connect one circuit of LCRA's 345 KV transmission lines from Austrop Substation and Zorn Substation (three circuit breakers), the jointly owned transmission line from Holman Substation (two circuit breakers) and Austin's 138 KV transmission line from Pilot Knob Substation. The substation will be arranged to have two main buses connected by tie buses for operation at 345 KV and two main buses connected by tie buses for operation at 138 KV. Each tie bus will have 2 or 3 circuit breakers connected in series along its length. The section of a tie bus between two circuit breakers will provide a circuit connection point. This substation arrangement is commonly known as a "breaker-and-a-half" arrangement. The 138 KV buses will be initially connected to the 345 KV buses through a single auto-transformer.

5.9.1.2 Single side band power line carrier equipment and protective relaying for the transmission line from Lytton Springs to Holman Substation including line trap, coupling capacitors, line tuner, four-channel single side band power line carrier and one terminal of protective relaying.

5.9.2 Construction, Installation, Allocation of Costs: Austin shall acquire the site for, construct

Pg. 1 Mgr.

this substation and install all equipment at its cost except the costs associated with the termination of one circuit of LCRA's 345 KV transmission lines from Zorn and Austrop Substations; one-half of the cost associated with the termination of the jointly owned 345 KV transmission line from Holman Substation and one-half the cost associated with the communication and tie line telemetering equipment, ~~all of which~~ shall be paid by LCRA.

5.9.3 Ownership: Austin shall own the substation and all equipment except the termination facilities for LCRA's 345 KV transmission lines which will be owned by LCRA; the termination facilities for the initial circuit on the 345 KV line from Holman Substation which will be jointly owned until the second circuit is installed. When the second circuit is installed, an adjustment in the ownership of the termination facilities for the two circuits on the 345 KV line from Holman Substation including relaying and communication equipment shall be made so that LCRA will own the terminations associated with the second circuit and those associated with the initial circuit shall belong to Austin.

5.9.4 Additional Installations: LCRA may elect at its cost to terminate the second circuit on its 345 KV transmission line between Zorn and Austrop Substations at this substation with prior engineering approval of Austin. If LCRA has not elected to make this termination, then Austin may do so at its cost.

5.9.5 Breaker Operations:

5.9.5.1 The breakers terminating LCRA's 345 KV Austrop and Zorn lines and the jointly owned 345 KV line from the Project shall be joint interest breakers under the operational supervision of Austin. LCRA shall have the right to install supervisory control equipment for these breakers and in such event, the parties shall have joint operational supervision of them.

5.9.5.2 The breakers terminating the 345/138 KV 480 MVA auto transformer and all 138 KV breakers shall be under the sole control of Austin.

5.9.5.3 In the event the second circuit is installed on the 345 KV line from the Project the breakers on the initial circuit shall be under the sole control of Austin. The parties shall exchange breaker ownership on this termination to the extent necessary to maintain metering and control integrity including telemetering, relaying communications and other termination equipment.

5.9.5.4 In the event the second circuit on the Zorn to Austrop 345 KV line is terminated at this substation by either party the breakers will be joint interest breakers under the operational supervision of Austin unless LCRA installs supervisory control equipment in which event the breakers will be under joint operational supervision.

5.9.6 Maintenance: Austin shall maintain at its cost all equipment at this substation except that the termination equipment of the transmission line from Holman Substation shall be maintained by Austin for the joint account of the parties and the switchyard equipment for the termination of the transmission lines from Lytton Springs Substation to Austrop and Zorn Substations shall be maintained by LCRA for its own account.

5.10 TRANSMISSION LINE FROM LYTTON SPRINGS SUBSTATION TO MONTOPOLIS SWITCHING STATION

5.10.1 Description: A new 138 KV transmission line with double circuit structures from Lytton Springs

Substation via Austin's proposed Pilot Knob Substation to Austin's Montopolis Switching Station to be built on an existing right-of-way of LCRA a distance of approximately fifteen (15) miles. One side of the structures will carry Austin's 138 KV bundled 795 MCM, ACSR circuit and the other side to carry LCRA's existing 69 KV line. The existing structures on such right-of-way shall be removed and LCRA's present conductors transferred to the new structures.

5.10.2 Installation and Allocation of Cost: The removal of existing structures, installation of new structures and transfer of existing conductors shall be done by Austin at its cost initially. After the new structures and foundations therefor are designed, Austin agrees to supply LCRA with those figures which represent the estimated cost of the design, construction and installation of the new structures. Further, Austin will supply LCRA with the actual cost figures for the design and installation of the new structures when installation of such structures is complete.

5.10.3 Subsequent Capacity Increase by LCRA: If subsequent to the installation of the new structures LCRA desires to increase the capacity of its present conductors, it may do so at its cost and shall pay Austin a sum equal to one-half of the installed cost of the double circuit structures.

5.10.4 Ownership and Maintenance:

5.10.4.1 Right-of-way: The right-of-way shall be jointly owned and LCRA shall execute such transfer of interest as may be required to establish such ownership of record. Maintenance of the right-of-way shall be by Austin for the joint account of the parties.

5.10.4.2 Conductors: Each party shall own and maintain their respective conductors.

5.10.4.3 Structures: The structures shall be owned and maintained by Austin for its account until LCRA increases the capacity of its conductors; thereafter the structures shall be jointly owned and Austin shall execute such transfer of interest as may be required to establish such ownership of record. Maintenance thereafter shall be by Austin for the joint account of the parties.

5.10.5 Salvage and Additional Right-of-way Expense: LCRA shall be entitled to all salvage resulting from the dismantling of its existing structures, and Austin shall reimburse LCRA for any right-of-way costs or damages it may be required to pay as a result of Austin's removal of the existing structures and installation of the new structures.

6. COMMUNICATION FACILITIES AGREEMENT

6.1 LCRA'S MICROWAVE SYSTEM

6.1.1 Austin grants LCRA for a period of thirty years or so long as LCRA maintains a microwave system, whichever is the lesser time, the right to use without cost one-half of Austin's Control House and use of existing microwave tower at Tom Miller Dam for LCRA's microwave system equipment. Austin will also install and maintain air conditioning equipment at the control house at its expense.

6.1.2 LCRA shall provide Austin, at no cost, channel space in its microwave system between its SOCC and the Project so that Austin may communicate with Lytton Springs and Holman Substations and the Project from LCRA's SOCC. LCRA shall provide and install for the joint account of the parties all multiplex and interface equipment necessary to perform this function.

6.1.3 Austin shall have access at LCRA's SOCC to all Project tie-line and generation quantities necessary for reliable operation of Austin's Electric system and to all telemetering and supervisory control channels for Lytton Springs and Holman Substations via the Project Switchyard. Such quantities shall be applied to leased pairs or a microwave radio link or both to Austin's Energy Control Center. Such pairs or microwave radio link are to be purchased, installed, operated and maintained by Austin at its cost. Austin shall have access to LCRA's microwave tower for installation of Austin's radio antenna to the extent design loading permits.

6.1.4 Austin shall reimburse LCRA for any future interface equipment at Austrop Substation necessary for connection of any future Austin microwave systems to LCRA's microwave system at base band frequencies. If Austin installs its own microwave system, LCRA will permit Austin the use of LCRA's house and tower at Austrop Substation at no charge to Austin.

6.1.5 Austin shall purchase and install the necessary equipment to provide Automatic Generation Control of its electric system as soon as practical but in no case later than the commercial operating date of Fayette Power Project Unit No. 1.

7. OPERATING AGREEMENTS

7.1 LINE LOSS DETERMINATION

Under the terms of the Participation Agreement the Net Energy Generation of the Project's Units 1 and 2 will be available to LCRA and Austin in equal amounts at the Project Switchyard. Power and energy scheduled to be taken by each party for its account will be measured at the high voltage terminals of the generators' step-up transformers. Under the transmission system contemplated hereby a portion of the power and energy scheduled for Austin's account from the Project will flow through LCRA's transmission system and enter Austin's system at existing tie points between the two systems (Decker, Hi-Cross, McNeil and Austin Dam Substations) and at any future tie points such as Marshall Ford, Project Switchyard and Lytton Springs Substation and a portion of the power and energy scheduled for LCRA's account will flow through Austin's transmission system from the Project Switchyard to Lytton Springs Substation and enter LCRA's system there. Since the power will flow along diverse routes in accordance with the voltages and impedances existing at any given time and subject to constant change of these quantities as a function of time an exact calculation of line losses attributable to the scheduled quantities which flow in the respective systems is difficult, if not impossible, to precisely measure; consequently, the parties agree upon the following procedure to arrive at a practical and realistic determination and allocation of such line losses and the sharing thereof:

7.1.1 Definition of Circuits and Assumed Flow:

7.1.1.1 All power scheduled from the Project for Austin's account will be assumed to flow on the circuits from the Project to Austrop Substation, thence through Austin's 345/138 KV auto transformer and thence on Austin's 138 KV transmission line to Austin's Decker Plant (the North Circuit) and from the Project on the joint 345 KV transmission line to Lytton Springs Substation (the South Circuit).

7.1.1.2 Fifty percent (50%) of all power scheduled from the Project for LCRA's account will be assumed to flow on the North and South circuits and shall be designated as KA.

7.1.1.3 The sum of 7.1.1.1 and 7.1.1.2 shall be the combined power flow on the North and South circuits.

7.1.2 Assumptions as to Load Level of the Two Circuits: The percentage of the combined power flow which is assumed to flow on the North Circuit (KN) is 60 and the percentage of the combined power flow which is assumed to flow on the South Circuit (KS) is 40. These values are based on the circuit configuration shown on Exhibit A and will be modified in accordance with 7.1.3.4 below in case of prolonged circuit outage. If significant changes are made in the circuit configuration from that shown on Exhibit "A" these values may require modification since they are derived solely from circuit configurations.

7.1.3 Calculation of Loss

7.1.3.1 The loss attributable to Austin because of power flow on the North Circuit shall be calculated at least hourly with the following formula:

$$CL = \frac{(AN+CN) \times CN \times LN}{100 \times 100}$$

$$AN = \frac{KN \times KA \times AT}{100 \times 100}$$

$$CN = \frac{KN \times CT}{100}$$

WHERE:

CL = the calculated losses in KILOWATTS attributable to Austin for the period;

AN = LCRA's calculated power flow in MW on the North circuit;

AT = LCRA's share of the total power in MW scheduled from the Project;

CN = Austin's calculated power flow in MW on the North circuit;

CT = Austin's share of the total power in MW scheduled from the Project;

LN = the base losses in Kilowatts on the North Circuit calculated for a power flow of 100 MW at a power factor of 0.85;

KA = 50

KN = 60

7.1.3.2 The loss attributable to LCRA because of power flow on the South Circuit shall be calculated at least hourly with the following formula:

$$AL = \frac{(AS + CS) \times AS \times LS}{100 \times 100}$$

$$AS = \frac{KS \times KA \times AT}{100 \times 100}$$

$$CS = \frac{KS \times CT}{100}$$

WHERE:

AL = the calculated losses in KILOWATTS attributable to LCRA for the period;

AS = LCRA's calculated power flow in MW on the South circuit;

CS = Austin's calculated power flow in MW on the South circuit;

LS = the base losses in Kilowatts on the South circuit calculated for a power flow of 100 MW at a power factor of 0.85;

KS = 40; and

AT, CT, KA, and KN have the values expressed in 7.1.3.1

7.1.3.3 The base losses on the North Circuit (LN) and on the South Circuit (LS) will be calculated when the design and routing of the transmission facilities are available in sufficient detail to allow accurate computation using techniques in general use by the electric utility industry.

7.1.3.4 Prolonged Outage Adjustment - In the case of prolonged outage lasting 72 hours or more, or

3/24/77

construction delay, the following values will be used for KA, KN and KS:

7.1.3.4.1 <u>Contingency A</u>: Unavailability of the circuit from the Fayette Power Project 345KV bus to the Authority's Fayetteville Substation 138KV bus. KA = 100 KN = 60 KS = 40

7.1.3.4.2 <u>Contingency B</u>: Unavailability of the South circuit. KN = 100 KS = 0 KA = 50

7.1.3.4.3 <u>Contingency C</u>: Unavailability of the North circuit. KA = 50 KN = 60 KS = 40

7.1.3.4.4 <u>Contingency B and C</u>: The constants are: KA = 0 KN = 250 KS = 0

7.1.3.4.5 <u>Contingency A and C</u>: The constants are: KS = 100 KA = 100 KN = 0

7.1.3.4.6 <u>Contingency A and B</u>: The constants are: KA = 100 KN = 100 KS = 0

The change in constants used for the loss calculations will be made only after 72 hours of operation with the new circuit configuration.

7.1.4 In scheduling power and energy from the Project under Section 7 of the Participation Agreement, each party shall include in addition to the quantity such party expects to receive into its electric system an allowance for anticipated line loss attributable to it under the foregoing provisions. This total shall not exceed the generating capacity and energy entitlement of such party when the other party is scheduling its maximum entitlement. As calculations of losses are made periodically as above provided, the quantity scheduled from the Project by such party shall be adjusted to reflect the calculated loss attributable to it so that the net generation scheduled for the account of such party shall include the aggregate line loss attributable to such party.

7.2 OPERATION OF JOINT INTEREST BREAKERS

Except in the event of an emergency where injury to persons or serious damage to facilities is anticipated, no action with respect to a joint interest breaker shall be taken by a party having operational supervision of such breaker without giving at least two hours prior notice to the dispatcher of the other party so that such dispatcher shall have time to take any precautionary actions necessary to protect the security of his system.

7.3 OPERATION OF SOLE CONTROL BREAKERS

The operation of breakers under the sole control of a party shall be operated at the complete discretion of such party.

7.4 LINE CLEARANCES

Line clearances (other than emergencies as defined above) on the 345 KV lines between the Project and Austrop, Fayetteville and Holman Substations and between Holman and

Lytton Springs Substations shall be coordinated by the Management Committee.

7.5 COMPLETION PRIORITIES

7.5.1 The Project to Austrop Substation transmission line and terminations and the Project to Fayetteville Substation transmission line, terminations and autotransformer shall be completed in conjunction with Project Unit No. 1.

7.5.2 The Project to Holman Substation transmission line and terminations and the Holman to Lytton Springs transmission line and terminations shall be completed in conjunction with Project Unit No. 2.

7.5.3 The completion of the transmission line from the South Texas Nuclear Project to Holman Substation and the 138 KV double circuit transmission line from Lytton Springs Substation to Montopolis Switching Station shall be as soon as deemed practicable by Austin.

7.6 WHEELING CHARGES

No wheeling charges are to be assessed by either party for energy and power transfers from the Project to the other party under this agreement. This shall in no way limit separate agreements pertaining to mutually agreed upon wheeling and loss charges for either purchase or sales of power and energy by either party to or from a third party or transmission of power from the South Texas Nuclear Project.

The parties recognize that the problems of wheeling power are associated with the Texas Interconnected System and should be covered by guidelines adopted by the members of that system. Until such guidelines are developed and agreed to, interim problems shall be settled by mutual negotiation between the utility systems involved.

7.7 START-UP TRANSFORMER AND PUMPING POWER

The power and energy for the 138 KV start-up transformer to supply start-up power and energy to Project Units 1 and 2 and for pumping water for the Project shall be metered on the 138 KV side of the start-up transformer. The cost of such power and energy will be an operating cost of the Project and shall, in the absence of a formal agreement between the parties thereto, be provided in accordance with the standard rate tariffs of LCRA applicable to such loads.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the _____ day of __________________ 1977.

CITY OF AUSTIN

ATTEST:

Grace Monroe

City Clerk ~~Secretary~~

By Homer D. Reed
City Manager

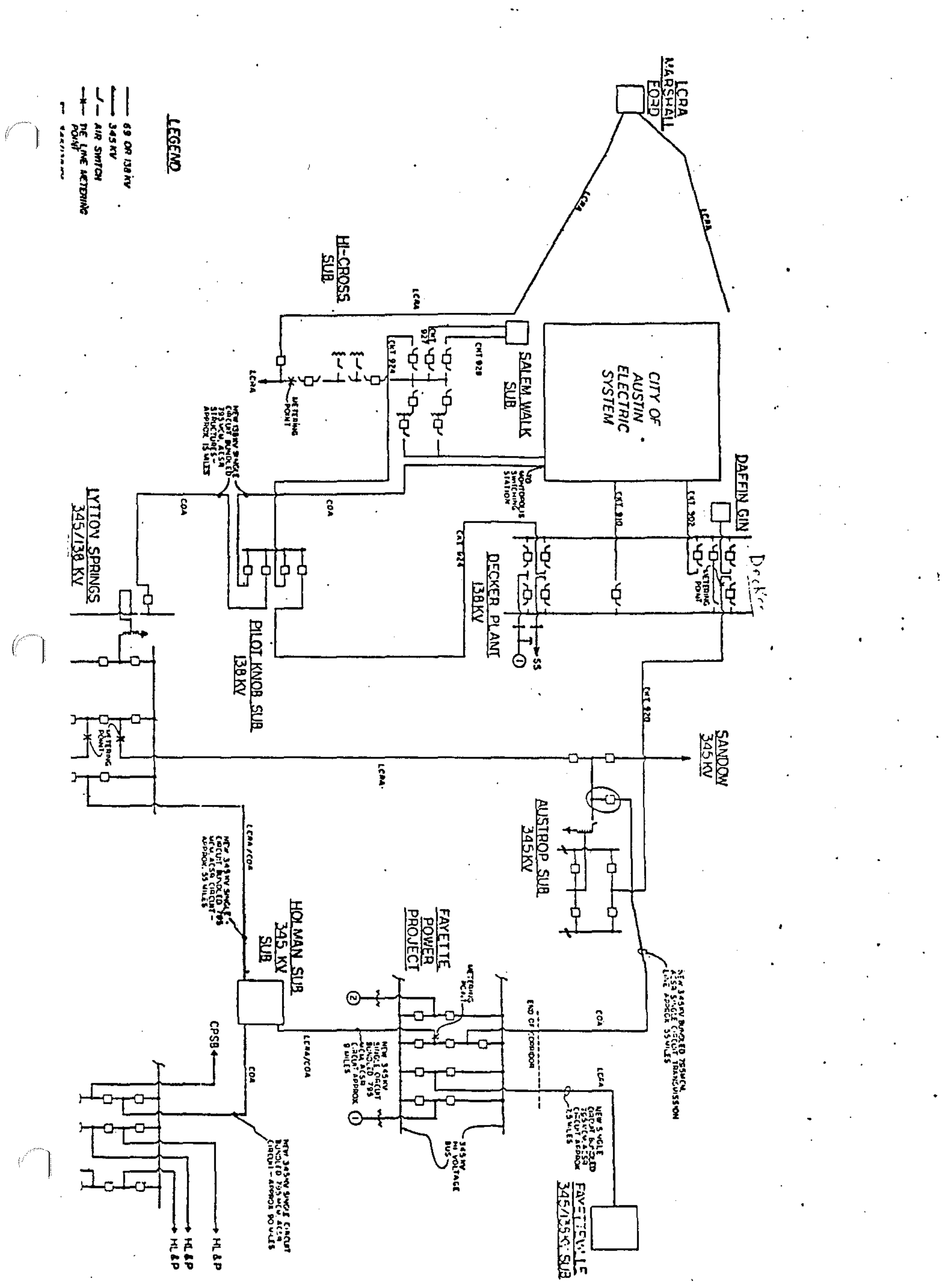
LOWER COLORADO RIVER AUTHORITY

ATTEST:

W. W. Conway

Asst. Secretary

By Charles Herring
General Manager


LEGEND
69 OR 138 KV
345 KV
AIR SWITCH
TIE LINE METERING POINT
LCRA MARSHALL FORD
LCRA
HI-CROSS SUB
SALEM WALK SUB
CITY OF AUSTIN ELECTRIC SYSTEM
DAFFIN GIN
CKT 928
CKT 924
CKT 910
CKT 902
METERING POINT
COA
LYTTON SPRINGS 345/138 KV
PILOT KNOB SUB 138 KV
DECKER PLANT 138 KV
SANDOW 345 KV
AUSTROP SUB 345 KV
CKT 920
LCRA/COA
HOLMAN SUB 345 KV SUB
FAYETTE POWER PROJECT
END OF CORRIDOR
FAYETTEVILLE 345/138 KV SUB
345 KV HI VOLTAGE BUS
CPSB
HL&P

Board Min. 81-213
1 Trans LWA 12720

State of Texas §
County of Travis §

1981 TRANSMISSION AGREEMENT BETWEEN LOWER COLORADO RIVER AUTHORITY AND CITY OF AUSTIN

This Agreement, hereinafter referred to as the "1981 Transmission Agreement", between the Lower Colorado River Authority, hereinafter called "Authority" acting pursuant to a resolution by its Board of Directors, and the City of Austin, a municipal corporation, situated in Travis County, Texas, acting pursuant to a resolution of its City Council, hereinafter called "City"; WITNESSETH:

I.
CONSIDERATION

City desires to construct certain facilities on certain Authority right-of-way, and Authority agrees to allow City to acquire and construct said facilities, and to cooperate with City in said construction, as hereinafter set forth. Consideration for this agreement consists of the mutual agreements contained herein and the mutual benefits to accrue to both parties.

II.
PRIOR AGREEMENTS

A. City and Authority, for their mutual benefits, have entered into several agreements prior to this 1981 Agreement.

1. The "1966 Agreement" dated December 15, 1966 provided for joint use by both parties of existing rights-of-way. The portions of the 1966 Agreement which are most pertinent to this 1981 Agreement are as follows:

(a) Article XI, Subsection E-3, of said 1966 Agreement, which contemplates mutual agreement to construct additional projects.

(b) Paragraph F of said Article XI, which provides for specific authorization by both parties of said additional projects after detail design and cost estimates have been made and prior to construction.

(c) Paragraph G of said Article XI, which provides a method of sharing cost on transmission structures which are to be jointly used.

2. The "1975 Agreement" dated April 4, 1975, provided for certain joint use agreements on the Hi-Cross to Decker line. The portions of the 1975 Agreement which are most pertinent to this 1981 Agreement are as follows:

(a) Article III, Subsections A(1) and A(2), which provide for joint use of the existing Authority rights-of-way from Hi-Cross Substation to a point approximately 6.96 miles east of said substation.

(b) Article IV, Subsections A and B, which provides for the payment of cost for the jointly used facilities identified in subsection (a) above.

3. The "1978 Agreement" dated December 7, 1978 provided for certain joint use of facilities between City's proposed Commons Ford Substation to City's Jett Substation, and from Hi-Cross Substation to a point 6.96 miles east of Hi-Cross Substation all of which is shown on Exhibit A attached to the "1978 Agreement".

III.

1981 AGREEMENT TERMS

A. City agrees to acquire ownership of Authority's existing 69 Kv transmission line including all rights-of-way from the point where it first contacts the Marshall Ford Substation dead-end structure to the point where it first contacts Authority's 69 Kv double circuit structure located three spans from the Austin Dam Substation. From this latter point, Authority shall retain ownership of the three double circuit structures into Austin Dam Substation, but will transfer ownership to City of the conductors, insulators, and hardware on one side of these towers along with the right to occupy said position henceforth. City has the right to make modifications to these double circuit towers at City's own expense. Between the Austin Dam Substation and Texas Highway Loop 360 modifications and uprating of the 69 Kv transmission line shall not exceed one (1) 138 Kv transmission line; the transmission line shall be placed on single pole steel structures minimizing right-of-way requirements; and, the line shall be strung so as not to require any right-of-way clearing except where single pole steel structures are placed. In consideration for said transfer, City shall pay to Authority a sum of money equal to $75,000. The location of this line is shown on Exhibit "A".

B. City will provide at no cost to Authority, wheeling privileges through City's Electric System into Authority's Electric System for the power and energy generated at Authority's Austin Dam hydroelectric facilities. In addition, there shall be no charge to Authority for losses incurred in City's system as a consequence of this power and energy flow through City's system into Authority's system. This provision will not be valid if this power and energy is used directly or indirectly to serve any Authority customer loads within City's certificated service area, unless said Customer is served by Authority at the request of City.

C. Article III, Subsection A(1) and A(2) and Article IV of the "1975 Agreement", as well as the "1978 Agreement", shall be amended such that Authority shall uprate the Hi-Cross to Gideon 138 Kv line when Authority deems it necessary without reimbursing City for 50% of the existing structure costs between Hi-Cross Substation and the junction point 6.96 miles east of Hi-Cross Substation, as stipulated by the said provisions contained in the 1975 and 1978 Agreements as shown on attached Exhibit "A".

IV.

RATIFICATION OF PRIOR AGREEMENTS

With the exception of the specific amendments addressed in this 1981 Agreement, all other portions of the prior agreements are hereby ratified, affirmed, and approved.

IN WITNESS WHEREOF the parties hereto have caused this 1981 Agreement to be executed by their duly authorized officers this 3rd day of November, 1981.

ATTEST:

Grace Monroe

City Clerk

CITY OF AUSTIN

By Thomas H. Mueller

City Manager

ATTEST:

Thomas W. Fawcett

Assistant Secretary

LOWER COLORADO RIVER AUTHORITY

By Elof H. Soderberg

Interim General Manager

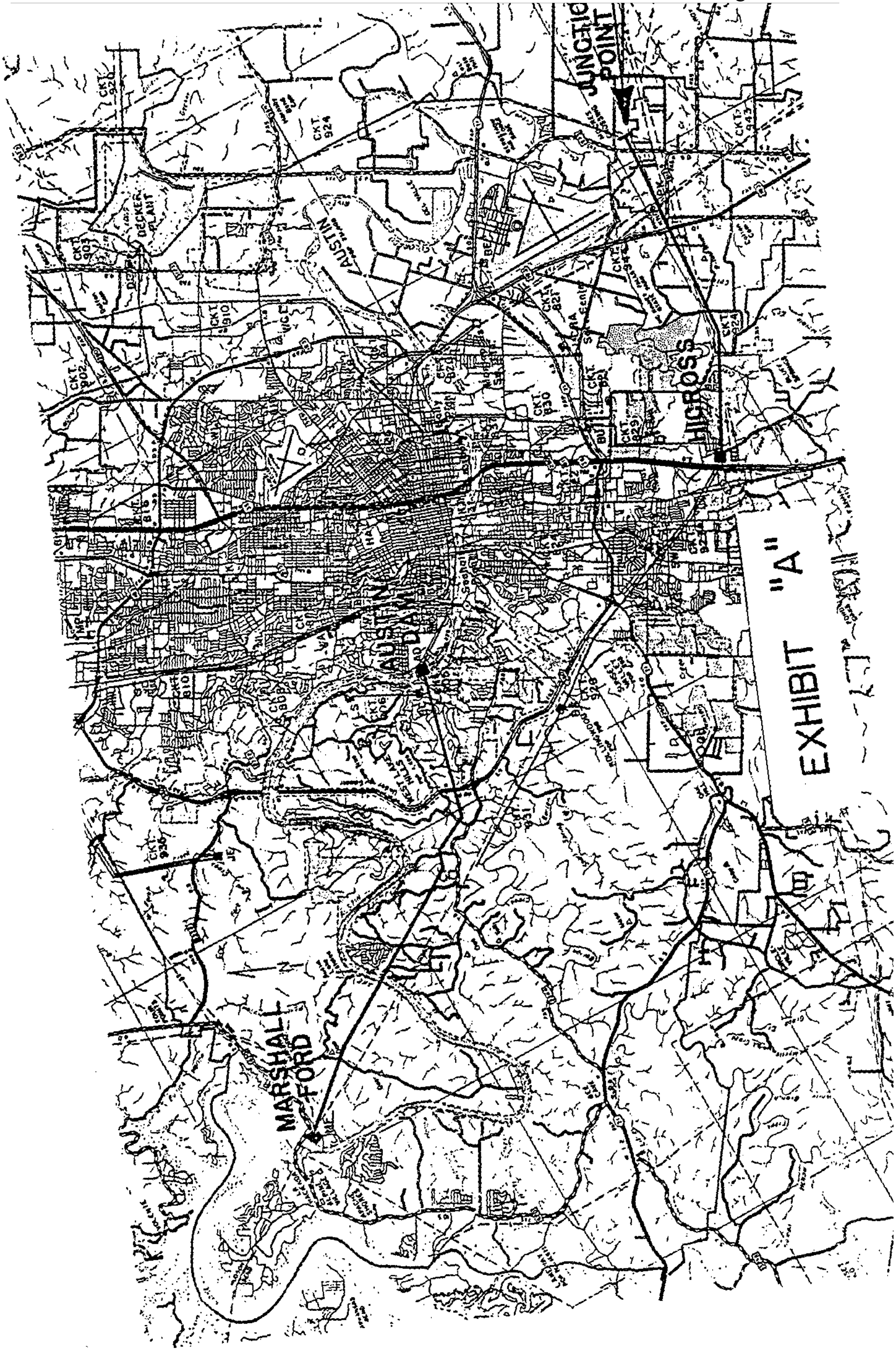


EXHIBIT "A"
JUNCTION POINT
HICROSS
AUSTIN DAM
MARSHALL FORD
DECKER PLANT
AUSTIN

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

1983 TRANSMISSION AGREEMENT BETWEEN LOWER COLORADO RIVER AUTHORITY AND CITY OF AUSTIN

This Agreement, hereinafter referred to as the "1983 Transmission Agreement", between the Lower Colorado River Authority, hereinafter called "Authority", acting pursuant to a resolution by its Board of Directors and the City of Austin, a municipal corporation, situated in Travis County, Texas, acting pursuant to a resolution of its City Council, hereinafter called "City";

W I T N E S S E T H:

I.
CONSIDERATION

City desires to acquire and construct facilities on right-of-way and property now owned by Authority, and Authority agrees to allow City to acquire and construct said facilities, and to cooperate with City in said construction, as hereinafter set forth. Consideration for this agreement consists of the mutual agreements contained herein and the mutual benefits to accrue to both parties.

II.
PRIOR AGREEMENTS

A. City and Authority, for their mutual benefits, have entered into two agreements prior to this 1983 Agreement, which relate to this 1983 Agreement as follows:

1. The FAYETTE POWER PROJECT TRANSMISSION AGREEMENT dated March 17, 1977, hereinafter termed "The 1977 Agreement".

Section 5.10 of the 1977 Agreement provides for joint construction of a double-circuit line from Lytton Springs Substation to Montopolis Switching Station. This 1983 Agreement supercedes Section 5.10, but leaves all other sections of the 1977 Agreement in full force and effect.

2. The 1981 TRANSMISSION AGREEMENT, dated November 3, 1981. Section III-A of the 1981 Agreement provides for the acquisition by City of a portion of existing Authority's 69 Kv transmission lines and identifies portions of the double-circuit structures and conductors comprising the first three spans which cross the Colorado River out of Austin Dam Substation. Section III-B, provides wheeling privileges for the power from Authority's Austin Dam hydroelectric generators through City's system. This 1983 Agreement modifies Section III-A to include in the transfer the double-circuit portion (first 3 structures) as hereinbelow described, and supercedes III-B of the 1981 Agreement, but leaves all other sections of the 1981 Agreement in full force and effect.

III.
1983 AGREEMENT TERMS

A. Authority hereby sells and conveys to City ownership of Authority's existing 69 Kv transmission line as is including all rights-of-way from the point where it first contacts the Colton Substation deadend structure to Montopolis Switching Station, a distance of approximately 6.24 miles, as shown on the attached map, called Exhibit I. Transfer of right-of-way easements shall be accomplished by a separate document.

B. Authority hereby sells and conveys to City ownership of Authority's existing 69 Kv transmission line as is, including all rights-of-way from the Austin Dam Substation to its termination at Montopolis Switching Station, a distance of approximately 10.4 miles, as shown on Exhibit I. This ownership includes the first three spans of conductors comprising two circuits and their double circuit structures which cross the Colorado River in a south-westerly direction from Austin Dam Substation. Transfer of right-of-way easements shall be accomplished by a separate document.

C. Authority hereby sells and conveys to City ownership of the Montopolis Switching Station including all equipment and structures. The real property is owned by City.

D. Authority shall continue to operate and maintain the facilities described in Paragraphs A, B, and C above and the Austin Dam to Marshall Ford line described in the 1981 Transmission Agreement until City requires the use of any part of these circuits which interrupts the transmission continuity from Austin Dam Substation to Colton Substation or the transmission continuity from Austin Dam Substation to Marshall Ford Substation. At such time as City interrupts the transmission continuity on either of these circuits, City shall electrically disconnect the appropriate circuit from the Austin Dam Substation in order to minimize the fault exposure of the Austin Dam hydroelectric plant. At such times, Authority may remove Authority's corresponding 69 Kv breakers, Nos 660 and 670.

E. City shall provide at no cost to Authority wheeling rights through City's Electric System into Authority's Electric System for the power and energy generated at Authority's Austin Dam hydroelectric facilities. There shall be no charge to Authority for losses, if any, incurred in City's system as a consequence of this power and energy flow through City's system into Authority's system. Authority shall continue to operate the Austin Dam and hydroelectric generation facilities under existing agreements. This paragraph shall not be construed in any way to prevent the flow of power and energy from the Austin Dam hydroelectric plant. City agrees that routine maintenance to City's part of Austin Dam Substation which limits or curtails the ability to deliver power and energy from the Austin Dam hydroelectric plant shall be coordinated with Authority in order not to cause unnecessary outages at the plant. City, however, shall not be liable for loss of power and energy sales from the plant due to a Force Majeure condition which limits or curtails generation.

F. City shall provide at Authority's cost 12 Kv feeders connected to Authoritv's administration building, environmental building, and shops. City shall provide billing metering equipment for these feeders, and the power and energy metered at Authority's 12 Kv delivery points shall be summed at the same utility interchange rate prevailing at the other Authority/City tie points.

G. In consideration of the value received by virtue of this 1983 Transmission Agreement, as described above, City agrees to pay to Authority $125,000.

RATIFICATION OF PRIOR AGREEMENTS

With the exception of the specific changes addressed in this 1983 Agreement, all other portions of the prior agreements listed herein are ratified, affirmed, and approved.

IN WITNESS WHEREOF, the parties hereto have caused this 1983 Agreement to be executed by their duly authorized officers this 1st day of November, 1983.

ATTEST:

James E. Aldridge
~~Secretary~~ Acting City Clerk

CITY OF AUSTIN

By: Jorge Carrasco
for City Manager

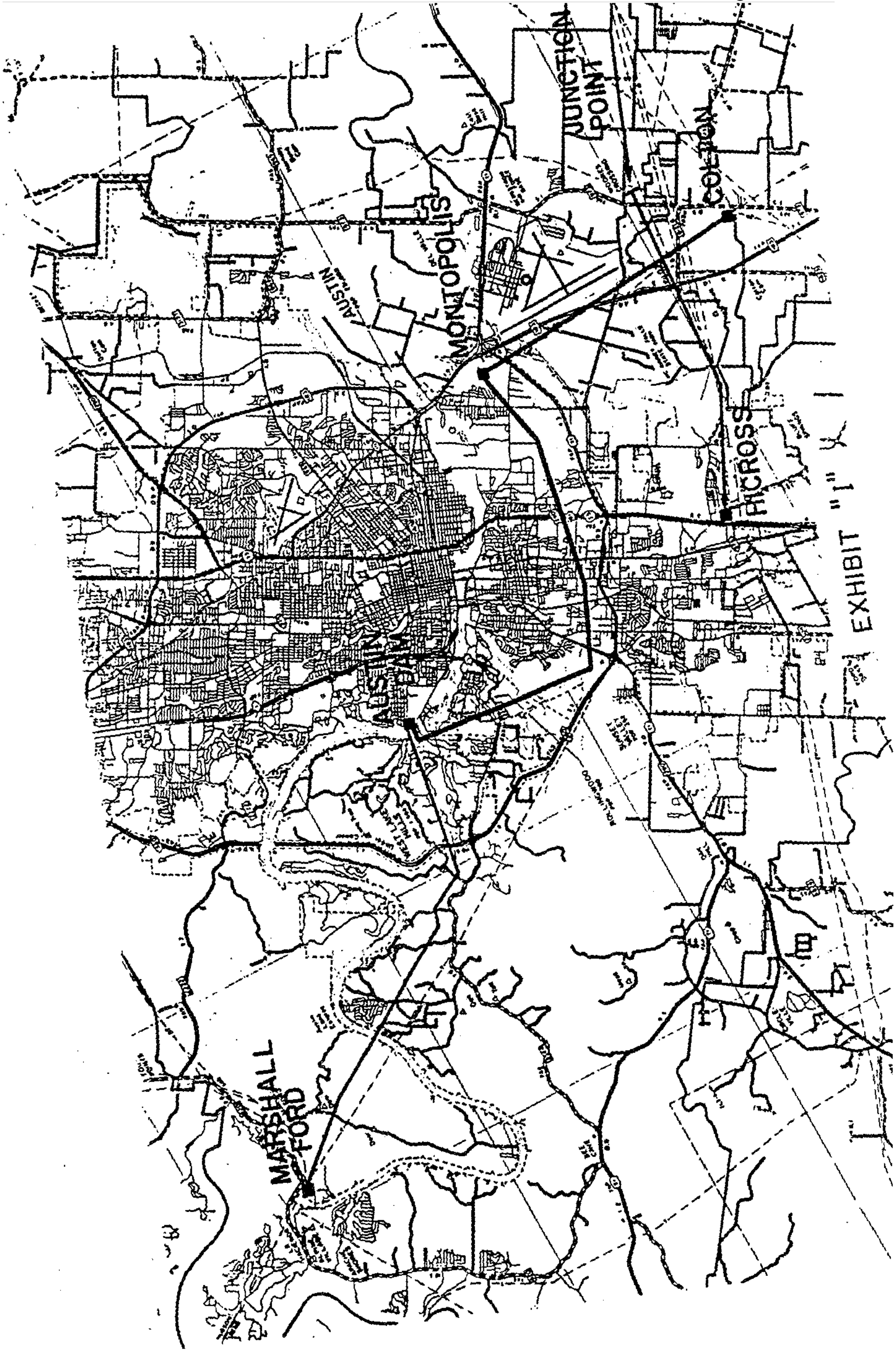
CJS

ATTEST:

Jesse F. Logan
~~Assistant~~ Secretary
Jesse F. Logan

LOWER COLORADO RIVER AUTHORITY

By: Elof H. Soderberg
Elof H. Soderberg
General Manager


JUNCTION POINT
COLTON
MONTOPOLIS
AUSTIN
HICROSS
EXHIBIT "1"
AUSTIN DAM
MARSHALL FORD

City of Austin
Founded by Congress, Republic of Texas, 1839
Municipal Building, Eighth at Colorado, P.O. Box 1088, Austin, Texas 78767 Telephone 512/477-6511

February 5, 1986

Lower Colorado River Authority

Attention: Mr. R. L. Hancock, Executive Director
Engineering and Operations

Subject: 1985 Transmission Agreement

Dear Mr. Hancock:

Attached herewith is your copy of the signed 1985 Transmission Agreement between the Lower Colorado River Authority and the City of Austin. Subject agreement was approved by the City Council on January 9, 1986.

Sincerely,

Gilbert W. Smith, Manager
Transmission and Distribution Engineering
Electric Utility

GWS:glh

Attachment

THE STATE OF TEXAS §
COUNTY OF TRAVIS §

1985 TRANSMISSION AGREEMENT BETWEEN THE LOWER COLORADO RIVER AUTHORITY AND THE CITY OF AUSTIN

This Agreement, hereinafter referred to as the "1985 Transmission Agreement", is entered into by and between the Lower Colorado River Authority, hereinafter referred to as "LCRA", acting pursuant to a resolution by its Board of Directors, and the City of Austin, a municipal corporation in Travis County, Texas, acting pursuant to a resolution of its City Council, hereinafter referred to as "City";

W I T N E S S E T H:

I.

CONSIDERATION

It is the intent and desire of both parties, as to the present Agreement as well as to previous transmission agreements, that shared easements, interconnections, and joint substation properties and other facilities shall ultimately benefit the rate-payers of both parties. City desires to acquire certain LCRA right-of-way easements for the purpose of constructing electric transmission, substation, and distribution facilities. LCRA desires to acquire certain rights to the use of facilities installed by City to improve its transmission system capability. Consideration for the terms of this agreement consists of the mutual benefits and rights to accrue to the parties hereto.

II.

PRIOR AGREEMENTS

City and LCRA for their mutual benefit have entered into several transmission agreements.

A. The Fayette Power Transmission Agreement dated March 17, 1977 provides, inter alia, for joint construction work and operations at Austrop Substation. Sections IIIE and IVE of this 1985 Transmission Agreement supplement existing provisions of said 1977 Transmission Agreement.

B. The 1983 Transmission Agreement dated November 1, 1983 provides in Section III F for the supply of electrical power and energy to LCRA's offices and shops near Austin Dam. One provision of this 1985 Transmission Agreement modifies said Section III F.

C. Various lease agreements are in existence pertaining to the lease from City of the land on which the LCRA offices and shops are situated. One provision of this Agreement clarifies certain of these leases.

III.

1985 TRANSMISSION AGREEMENT TERMS

NEW PROJECTS

A. McNeil to Howard Lane 138 KV Line

City desires to construct and operate a 138 KV transmission line from the existing LCRA/City McNeil Substation to a new City substation site on or near Howard Lane to be called Howard Lane Substation. To facilitate construction and operation of said transmission line, City desires to acquire ownership of a portion of an existing LCRA-owned transmission easement between McNeil Substation and Howard Lane; the location and description of said easement are shown on Exhibit I. Said easement is approximately 2.7 miles in length and is a portion of certain easements owned by LCRA along this general route. LCRA hereby agrees to transfer to City ownership of the described portion of said easements between McNeil Substation and a mutually agreeable location near Howard Lane. Transfer of right-of-way easements shall be accomplished by a separate document.

City agrees to construct and operate a 138 KV transmission line in said easements. The structures supporting this line shall be capable of supporting two 138 KV three-phase circuits, with each circuit consisting of two-per-phase 795 kcmil ACSR conductors. Design and construction of these structures and the transmission line shall be coordinated with and be agreeable with LCRA's engineering department. City shall utilize the western circuit position of the proposed transmission line. City shall bear the cost of all structures and foundations for said transmission line and the cost of the conductor, insulators, and hardware for its western circuit.

LCRA shall have the right at no cost to utilize the eastern circuit position for installation and operation of its own 138 KV circuit for as long as the McNeil Substation and lines emanating therefrom are integral to LCRA's transmission system. LCRA shall bear the cost of the insulators, hardware, and conductor for its eastern circuit. Design, construction, and operation of LCRA's circuit shall be coordinated with and be agreeable with City. Material procurement and construction work of the eastern circuit shall be performed by LCRA, or by City under separate agreement.

B. <u>345 KV Transmission Loop</u>

City desires to construct and operate a double circuit 345 KV transmission line from the LCRA/City Austrop Substation to the LCRA/City McNeil Substation, then from the LCRA/City McNeil Substation to the Marshall Ford area.

City intends to continue the double-circuit 345 KV transmission loop from the Marshall Ford area to a City substation to be located near Bee Caves, to be called City Trading Post Substation, and to continue the 345 KV transmission loop around City's service area to the LCRA/City Lytton Springs Substation. City's 345 KV transmission loop shall be constructed initially with one circuit, the second circuit to be constructed as the load requires it.

LCRA presently owns and operates a 69 KV line which extends a distance of approximately 14.5 miles between McNeil Substation and Marshall Ford Substation, this line being adjacent to and north of an existing City-owned 138 KV line between McNeil Substation and the Marshall Ford area. The location and description of these lines and easments are shown on Exhibit I. City desires to obtain ownership of this 69 KV line and the easement rights on which to construct and operate part of the aforementioned 345 KV transmission loop.

LCRA hereby agrees to transfer ownership to City of the aforementioned 69 KV line, including all right-of-way easements. Transfer of right-of-way easements shall be accomplished by a separate document. The foregoing notwithstanding, as a condition precedent to such transfer of right-of way easements, City agrees to conduct public hearings on the proposed transmission line on the LCRA rights-of-way from Marshall Ford to McNeil and to notify adjacent landowners of the proposed project. City shall remove existing facilities at its own expense before constructing the 345 KV line. All line materials removed shall become the property of City. LCRA shall retain ownership of the 69 KV breakers and related appurtenances at McNeil and Marshall Ford Substations and they shall remain in place for LCRA's removal.

As part of the consideration for the line and right-of-way easement transfer, LCRA shall have the right, for as long as transmission facilities in the area described in this Section are integral to LCRA's transmission system, to exercise any of the following options:

(1) to interconnect at no further cost to LCRA with City's 345 KV

facilities in the initial circuit at any points between and including Austrop Substation, McNeil Substation, and around the loop to Lytton Springs Substation or at points within any completed segments of this loop;

(2) to participate with City in the construction of the second circuit, or a mutually agreed upon portion of it;

(3) to construct, own, and operate at LCRA expense the second circuit on all or a mutually agreed upon portion of City's 345 KV structures;

(4) to purchase from City at original installed cost a mutually agreed upon portion of the transmission capacity of all or a part of the second circuit, in the event that City should have previously constructed said second circuit.

If either Option (2) or (4) is exercised, LCRA shall pay to City a prorated share of the original installed cost of right-of-way, structures, conductor, insulators, and hardware which shall correspond to LCRA's proportionate ownership of the 345 KV line.

If Option (3) is exercised, LCRA shall pay to City a prorated share of the original installed cost of right-of-way and structures which shall correspond to LCRA's proportionate ownership of the 345 KV line. In such a case, City shall have the right to purchase from LCRA at original installed cost a mutually agreed upon portion of the transmission capacity of all or a part of the second circuit; and City shall then repay to LCRA the appropriate share of the right-of-way and structure cost to reflect each party's proportionate ownership of the 345 KV line.

At such time as either party determines that the second circuit will be beneficial to its transmission system, that party shall notify the other party of its intention to construct and operate said circuit, and the party so notified shall indicate its intention to participate and shall execute a separate participation agreement within two years following notification if it desires to participate in the original construction.

LCRA agrees that all of its interconnections and new construction on this 345 KV loop shall be coordinated with and be agreeable with City so that all planning and operating criteria are met. Neither City nor LCRA shall be liable for any lease or wheeling charges for its connection to, use of, or participation in said 345 KV transmission facilities. This provision is not intended to exclude these circuits from loss assessments as provided for in other agreements.

C. Lakeway Cut-in

City shall have the right to interconnect a new substation into LCRA's 138 KV transmission line between LCRA Marshall Ford and LCRA Paleface Substations. Power and energy delivered at this location shall be summed for billing purposes in accordance with City's and LCRA's interchange agreement. This new substation shall be called City's Lakeway Substation and shall be limited to a load not exceeding 30 MVA. The interconnection is on a temporary basis, and it shall be removed at such time as City is able to construct its own transmission facilities into the area, but in any event no later than 1991. Design and construction of the 138 KV Substation including metering equipment required to account for the interchange shall be paid for by City and coordinated with and be subject to approval by LCRA's engineering department, because these facilities will be integral to LCRA's transmission system. The cut-in shall consist of, at minimum, a 3-way tap to allow LCRA to maintain either resulting segment of the Marshall Ford to Paleface line without causing a customer outage at City's facilities. City shall design and install, in coordination with LCRA's engineering department, sufficient protective devices at its substation to preserve the integrity of the transmission system. Upon disconnection of this temporary substation from LCRA's transmission system City shall pay for all removal costs required to restore LCRA's system to its original state.

D. Balcones Cut-in

LCRA shall have the right to interconnect the LCRA Balcones Substation into City's 138 KV transmission line between City Summit Substation and Hamilton Substation if such a project would be economically justified. Power and energy delivered at this location shall be summed for billing purposes in accordance with City's and LCRA's interchange agreement. The double circuit portion of line from City's 138kV line breakoff to Balcones Substation shall be re-conductored at LCRA expense with two-per-phase 795 kcmil ACSR to match City's Summit to Hamilton circuit capacity. Design, construction, and operation of the 138 KV breakers, buswork, and relaying at Balcones Substation including metering equipment required to account for the interchange shall be paid for by LCRA and coordinated with and be agreeable with City, because these facilities will be integral to City's transmission system.

E. Modifications at Austrop Substation

City desires to connect the new 345 KV transmission loop into Austrop Substation. LCRA and City agree that a conversion of the Austrop 345 KV Substation to a ring bus is necessary to accommodate the new 345 KV loop and to provide improved reliability for both utilities. LCRA shall be responsible for engineering, purchasing materials, and constructing the substation conversion. The final substation design shall be agreeable to both parties. Assessment of costs for the conversion of the 345 kV substation shall be consistent with ownership of the facilities, the specifics of which shall be agreed upon in a separate document. Upon completion of the work, City will have three terminations and LCRA four terminations. City agrees to pay LCRA for half the engineering costs (including administrative expenses) and 50% of the total cost of reconfiguring the buses as required for the conversion. City agrees to pay for all expenses incurred by LCRA associated with the City terminations such as structures, breakers, switches, potential transformers, protective equipment, etc.

Future 345 KV modifications at the Austrop Substation shall be agreeable with both LCRA and City and paid for by the party requiring the modification. Ownership of the 345 KV substation facilities shall correspond to ownership of line terminations.

F. Austrop to FPP 345 KV Transmission Line

City presently owns and operates a 345 KV transmission line on double-circuit structures with one circuit installed from the Fayette Power Project Switchyard to the Austrop Substation. Part of this line is constructed within the FPP Transmission Corridor which is jointly owned by City and LCRA. As part of the consideration for the line and right-of-way easement transfer described in Sec. B herein, LCRA shall have the right, for as long as transmission facilities in the area described in this Section are integral to LCRA's transmission system, to exercise any of the following options:

(1) to construct, own, and operate at LCRA's expense the second circuit on all or a mutually agreed upon portion of City's FPP to Austrop 345 KV structures;

(2) to participate with City in the construction of the second circuit, or a mutually agreed upon portion of it;

(3) to purchase from City at original installed cost a mutually agreed upon portion of the transmission capacity of all or a part of the second circuit, in the event that City should have previously constructed said second circuit.

If either Option (2) or (3) is exercised, LCRA shall pay to City a prorated share of the original installed cost of right-of-way, structures, conductor, insulators, and hardware which shall correspond to LCRA's proportionate ownership of the 345 KV line.

If Option (1) is exercised, LCRA shall pay to City a prorated share of the original installed cost of the right-of-way and structures which shall correspond to LCRA's ownership of the line. In such a case City shall have the right to purchase from LCRA at original installed cost a mutually agreed upon portion of the transmission capacity of all or a part of the second circuit, and City shall repay to LCRA the appropriate share of the right-of-way and structure cost to reflect each party's proportionate ownership of the 345 KV line.

At such time as either party determines that the second circuit will be beneficial to its transmission system, that party shall notify the other party of its intention to construct and operate said circuit, and the party so notified shall indicate its intention to participate and shall execute the appropriate participation agreement within two years following notification if it desires to participate in the original construction.

LCRA agrees that all of its interconnections and new construction on this 345 KV line shall be coordinated with and be agreeable with City so that all planning and operating criteria are met. Neither City nor LCRA shall be liable for any lease or wheeling charges for its connection to, use of, or participation in said 345 KV transmission facilities. This provision is not intended to exclude these circuits from loss assessments as provided for in other agreements.

G. 69 KV Tie at McNeil Substation

The 69 KV tie between City and LCRA at McNeil Substation (OCB2320) shall be operated normally open in order to avoid overloading LCRA's 69 KV system in the event of contingencies (outages of lines or substation components) in City's system. The tie shall remain available for emergency use and maintenance, and it shall be operated in coordination between City's ECC dispatcher and LCRA's SOCC dispatcher, until such time as either party removes its respective 69 KV facilities.

H. Distribution Facilities at LCRA Offices and Service Center

LCRA shall install a 69/12.5 KV power transformer in its Austin Dam Substation to serve its offices, shops, and environmental buildings. All distribution ductwork and circuits, including the ductwork located under Lake Austin Boulevard to serve the Shapiro Building, will be furnished, operated, and maintained by LCRA. The present 12.5 KV service to the Shapiro Building on City's distribution system shall remain in place for standby. Power and energy from City's system which is consumed by LCRA's buildings shall be summed for billing purposes in accordance with City's and LCRA's interchange agreement.

City shall supply 12.5 KV service to LCRA's Dalchau Service Center at locations to be determined in consultation with City. LCRA shall pay all costs incurred by City in providing additional service locations. The present standby service to the LCRA SOCC and the 69 KV tap to LCRA's Service Center Substation shall remain in place. Power and energy consumed at these locations shall be summed for billing purposes in accordance with City's and LCRA's interchange agreement.

I. Property Leases at Austin Dam

There are a number of existing lease documents and correspondence in the files of both parties pertaining to the land occupied by LCRA's office buildings, shops, and substation at Austin Dam. It is the intent of both parties that LCRA has a lease to all the property presently occupied by its facilities except that part occupied by City's section of the Austin Dam Substation and its control house.

IV.

1985 TRANSMISSION AGREEMENT TERMS

OPERATION AND MAINTENANCE

A. McNeil to Howard Lane 138 KV Transmission Line

City shall perform and pay for all maintenance on the new 138 KV double-circuit line described in Sec.IIIA, including the right-of-way, double-circuit structures, and initial transmission circuit installed on the structures. At such time as LCRA installs its circuit on the vacant position, then LCRA shall pay half the total maintenance cost of this shared right-of-way and of the double-circuit transmission structures. Each party shall pay for the maintenance of its own circuit, including conductors and insulators.

B. 345 KV Transmission Loop

City shall perform and pay for all maintenance of right-of-way, structures, and the initial transmission circuit. The cost of maintenance of these facilities upon exercise of Options 2, 3, or 4 as described in Section IIIB herein shall be prorated by mutual agreement according to each party's ownership of the facilities.

C. Lakeway Cut-in

LCRA shall maintain at its cost all rights-of-way associated with its Marshall Ford to Paleface transmission line. LCRA shall operate and maintain at City expense the 138 KV switches associated with this substation, which are integral to LCRA's transmission system. Maintenance of the 138 KV buswork, relaying, and all other facilities at this substation shall be performed and paid for by City.

D. Balcones Cut-in

LCRA shall maintain at its expense the Balcones Substation and the double-circuit line from the breakoff to the substation. City shall operate the 138 KV breakers and switches in this substation, which are integral to City's transmission system.

Maintenance of the 138 KV breakers, buswork, and relaying shall be performed by City or LCRA as mutually agreed to, coordinated with City, and paid for by LCRA.

E. Austrop Substation

All 345 KV breakers at Austrop Substation shall be capable of being operated by either City or LCRA. Operation shall be by mutual agreement of the two systems' control centers. Maintenance of the 345 KV facilities at Austrop shall be performed by City or LCRA, as mutually agreed to, and coordinated between the parties. Maintenance shall be paid for based on ownership of equipment. Maintenance of other items will be as provided for under previous agreements or as mutually agreed to by the parties.

F. Austrop to FPP 345 KV Transmission Line

City shall pay for all maintenance of right-of-way, structures, and the existing transmission circuit. At such time as LCRA installs its circuit on all or part of the vacant position, then LCRA shall pay a prorated share of the total maintenance cost of the portion of shared right-of-way and double circuit transmission structures. Each party shall pay for the maintenance of its own circuit, including conductor and insulators.

City shall perform maintenance of the shared facilities as required and shall invoice LCRA for its portion of the expenses in accordance with the above agreement terms.

IN WITNESS WHEREOF, the parties hereto have caused this 1985 Agreement to be executed by their duly authorized officers this 5th day of February, 1985.

ATTEST:

CITY OF AUSTIN

By:
~~City~~ Asst City Manager

ATTEST:

LOWER COLORADO RIVER AUTHORITY

Assistant Secretary

By
Elof H. Soderberg
General Manager


CKT. 3127
TRADING POST
MARSHALL FORD
HOWARD L
McNEIL
CK
CKT. 3125
AUSTIN
CKT 3126
AUSTR
LYTTON SPRINGS
CKT. 3120
TO FAYETTE
1985 LCRA - CITY OF AUSTIN
TRANSMISSION AGREEMENT
EXHIBIT I

City of Austin
Founded by Congress, Republic of Texas, 1839
Municipal Building, Eighth at Colorado, P.O. Box 1088, Austin, Texas 78767 Telephone 512/499-2(

February 5, 1986

R. L. Hancock, Executive Director
Engineering & Operations
Lower Colorado River Authority
P. O. Box 220
Austin, Texas 78767

Subject: Relocation of LCRA Transmission Facilities at McNeil Substation

Dear R. L.:

In connection with Austin's 345/138 KV autotransformer installation at McNeil Substation, certain LCRA transmission facilities require relocation in order to clear the proposed new substation construction. The Electric Utility requests that LCRA undertake the necessary relocations and that the actual cost incurred for the work be shared by Austin and the LCRA on an equal basis.

It is appropriate that this request be approved by LCRA. A similar agreement has been entered into by the parties with regard to the proposed bus revision at Austrop Substation, wherein Austin will pay for one-half of the actual cost of necessary transmission line modifications. In both cases, the proposed work will result in mutual benefits. Further, the substation property was originally purchased by Austin, and without the requested line relocations, cannot be used for the intended purpose.

Your favorable response to this request will be appreciated. Because of planned schedules for the substation construction, it is critical that this issue be resolved promptly. Please call if you have need for further information.

Sincerely,

H. L. Peterson
Deputy Director
Electric Utility

S1/24/14

LIGNITE MINING AGREEMENT

On the 31st day of January, 1984, the City of Austin (Austin) and Lower Colorado River Authority (LCRA) executed a MEMORANDUM OF UNDERSTANDING which inter alia stated generally in Section II 3 thereof, that Austin as a part of an overall agreement concerning Units 3 and 4 of the Fayette Power Project would authorize LCRA to develop and mine Austin's present and future mineral interests in LCRA's proposed Cummins Creek Mine for Fayette Project Units 3 and 4 as generally shown on the attached plat Exhibit A (the Mine). The parties now desire to enter into a definitive agreement to express specifically the terms and conditions governing the mining by LCRA of Austin's mineral interest.

1. Austin's Mineral Interest: Within the Mine area, Austin presently holds the following mineral interests:

(1) the Rohde Lease - an undivided one-half of the mineral leasehold working interest created by that certain mineral lease from James E. Rohde and wife Rose Marie Rohde to Lower Colorado River Authority and City of Austin dated Aug 22, 1983, recorded Vol. 643, page 684, Deed Records, Fayette County, Texas, covering 52.186 acres out of the R. G. Baugh 1/4 League A-12 in Fayette County, Texas (the Rohde Lease); and

(2) the Valero Leases - an undivided 18.007581% interest in the mineral leasehold working interest created by those

THIS CONTRACT IS SUBJECT TO ARBITRATION
UNDER THE TEXAS ARBITRATION ACT

certain leases covering lands lying in Fayette County, Texas, which were assigned by Valero Lignite Company to Central Power & Light Company, et al by assignment dated December 28, 1981, recorded in Vol. 594, page 415, Deed Records of Fayette County, Texas, subject to certain overriding royalties and other encumbrances. The balance of the working interest in the Valero Leases is owned in undivided interests by Central Power & Light Company, City Public Service Board of San Antonio and LCRA. The Valero Leases will, in the near future be partitioned so that each owner will have the full working interest in segregated portions of the Valero Leases. The parties recognize that in the event of such a partition, this agreement shall neither enhance or diminish either party's right to claim the full working interest in the Valero Leases encompassed by the Mine under a final partition, or be used by either party as the basis of a claim that either party should retain its undivided interest in the Valero Leases in the Mine area under such partition.

2. Authorization of Mining: Austin does hereby grant to LCRA the exclusive and irrevocable right to mine and produce any lignite interest of Austin in and under the above described leaseholds insofar as said leaseholds are included in the Mine. LCRA shall have exclusive control over the mining operations and Austin's rights shall be limited solely to the delivery to it of mined lignite as set forth herein.

3. Delivery of Austin's Share - When production of lignite from a lease in which Austin has an interest commences, LCRA shall credit to Austin's account all such lignite mined attributable to Austin's interest. At the time that such mining has reached a continuous and sustained rate, LCRA shall commence delivery to Austin or to its order and Austin agrees to receive and dispose of an annual volume of lignite equal to the lesser of the total tons actually mined during the preceding twelve (12) calendar months attributable to Austin's leasehold interest or one hundred thousand (100,000) tons. Tonnage attributable to Austin's interest over one hundred thousand (100,000) tons annually shall carry over into subsequent years. Delivery shall be made by LCRA into transportation or other receiving facilities provided by Austin at the point at which lignite from the Mine is delivered to the Fayette Power Project or such other point as the parties may agree to, at a quarterly rate of twenty-five thousand (25,000) tons, until Austin has received an amount of lignite equal to its percentage interest in the total volume of lignite that has been produced and saved from the leases in which it has as interest.

If additional production capacity is available after satisfaction of the volume of lignite required for Units 3 and 4 then the annual rate of delivery to Austin may be increased by mutual agreement.

4. Lease Expenses and Mining Costs -

(a) Austin shall be responsible for and arrange to pay all amounts required under the terms of the leases or the assignments under which Austin derives its interest in the Valero Leases necessary in the absence of mining operations, to maintain such leases and its interest therein in force, such as delay rentals or advance royalties attributable to its interest in the leaseholds;

(b) LCRA shall, for Austin's account, pay as the same becomes payable, all delay rentals or advance royalty required to maintain the Rohde Lease in force and to pay all production royalty and overriding royalty (net of Austin's share of any recoupable advance royalty), surface damages, and other amounts due to lessors or surface owners under the terms of any of the leases arising because of mining operations thereon attributable to Austin's interest in the leaseholds;

(c) Austin shall pay LCRA for each ton of lignite delivered to it hereunder a sum equal to LCRA's per ton mining cost at the time of delivery as hereinafter defined.

5. Billing and Payment - LCRA shall bill Austin for all amounts paid for Austin's account under 4(b) above promptly after payment and shall bill Austin quarterly for its per ton mining costs for each ton of lignite delivered during the preceeding quarter month. Payment of all invoices shall be made

within fifteen (15) days of their receipt. In the event payments are not made within the fifteen (15) day period, interest at the rate of twelve percent (12%) per annum shall be due and owing. In the event Austin is not satisfied with the computation of the per ton mining costs billed to it on any invoice rendered by LCRA, Austin shall promptly notify LCRA in writing of those portions of the computations with which it is not in agreement. The parties shall meet within ten (10) days of such notification in an effort to arrive at a mutually satisfactory computation. If the meeting does not resolve the matter, they shall immediately refer same to a mutually acceptable national independent accounting firm for the purpose of arriving at the correct computation. LCRA agrees to provide said firm with all necessary information requested to enable it to arrive at the computation. The findings made by the firm shall be final. Payment for the services rendered by the firm shall be made by Austin in the event said firm upholds the computation provided by LCRA or requires an adjustment downward of less than five percent (5%) of the amount in controversy, otherwise, LCRA shall be responsible for payment of such services. During the period of verification of the computation, Austin shall pay all invoices as rendered provided, however, that when the matter is finally determined by the parties or the independent accounting firm, LCRA shall pay Austin the amount of all overcharges, if

Appendix D:
Austin Energy System Loss Study for Fiscal Year 2018

For Preparation of a 2019 Rate Study

Final Report – Version 1.0

Prepared by
Austin Energy

May 2, 2019

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TABLE OF CONTENTS

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1 INTRODUCTION

This report presents the Austin Energy's fiscal year 2018 transmission and distribution system loss study for the preparation of a rate study. It provides a summary of the basis of loss calculations, methodologies used and the results.

The electric system, for the purposes of this study, is defined as the transmission and distribution system equipment required to distribute electrical power to each Austin Energy customer. Information about the Austin Energy power system configuration, equipment types and ratings, primary and secondary circuit types and lengths, historical data, and transformer loads was gathered to perform this analysis. The Austin Energy power system evaluated can be characterized by the following statistics and principal types of equipment as of Fiscal Year 2018:

Type	Quantity	Location of Loss Calculations
System Peak Demand	2,878 MW (1)	
Annual Net Energy for Load	13,936,605 MWh (2)	
Annual Energy Sales	13,409,802 MWh (2)	
Annual Losses	3.78 %	Exhibit A
Circuit-miles of Transmission		Exhibit B
345 kV	276.2 mi.	
138 kV	321.5 mi.	
69 kV	26.1 mi.	
Transmission Transformers	19	Exhibit C
Substation Transformers	168	Exhibit D
Circuit-miles of Distribution Operating at 12.5 kV	5,803 mi.	Exhibit E
Distribution Transformers	84,377	Exhibit F
Circuit-miles of Secondary Operating at 1.0 kV & below	7,522 mi.	Exhibit H
Street & Security Lights	65,042	Exhibit I

Notes:
(1) Peak Demand on July 23, 2018
(2) Based on Fiscal Year 2018

2 ANALYSIS SUMMARY

The calculated transmission and distribution system losses for fiscal year 2018 are summarized in the table below. Additional details of the loss calculations are included in Exhibits A through J. Charts illustrating the calculated losses by voltage level are given in Figure 1 and Figure 2.

Type	Annual Energy Losses (MWh)	Demand Losses at Peak (MW)
Transmission 345 kV	18,155	6.37
Transmission 138 kV	125,534	44.06
Transmission 69 kV	5,534	1.53
Distribution	155,986	49.08
Secondary	222,375	41.85
Non-Technical	(772)	0
TOTALS	526,803	142.89

Note: Lights were assumed to be off during the 2018 system peak.

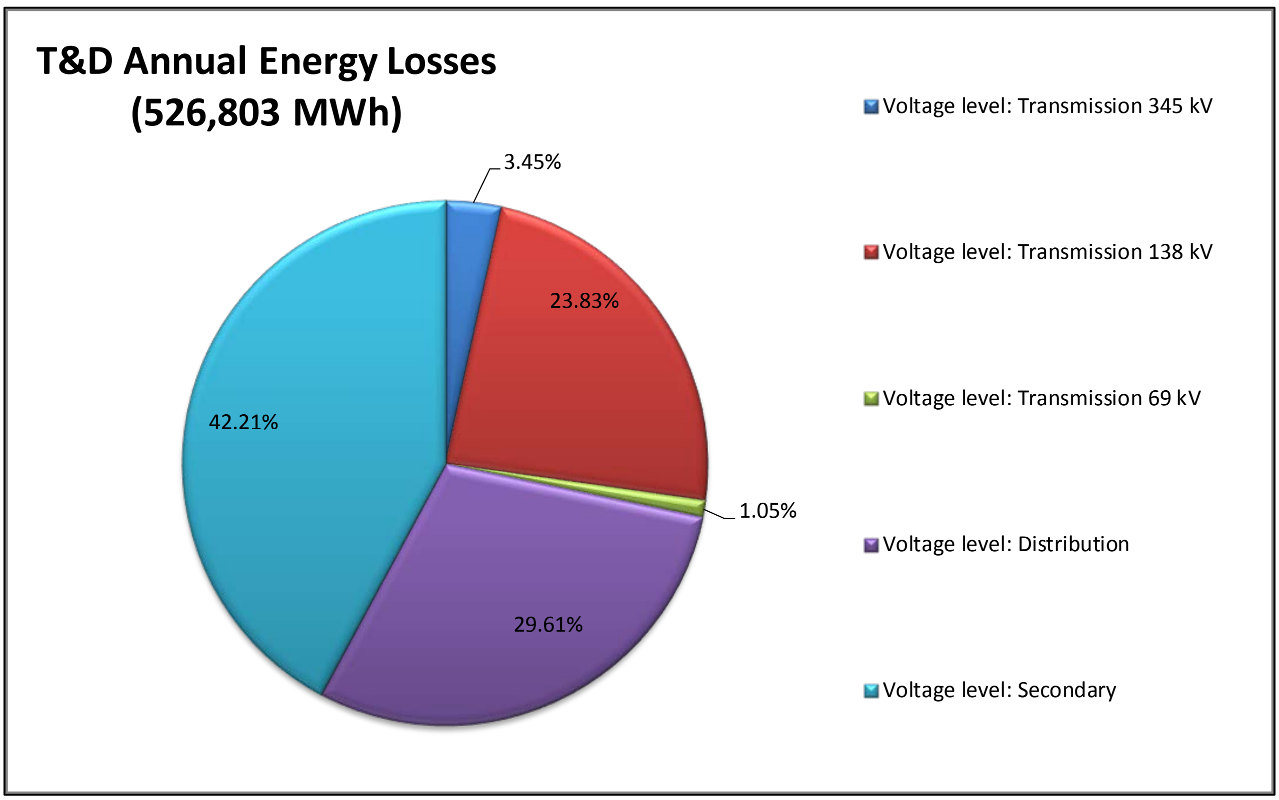


Figure 1. Calculated Annual Energy Losses by Voltage Level

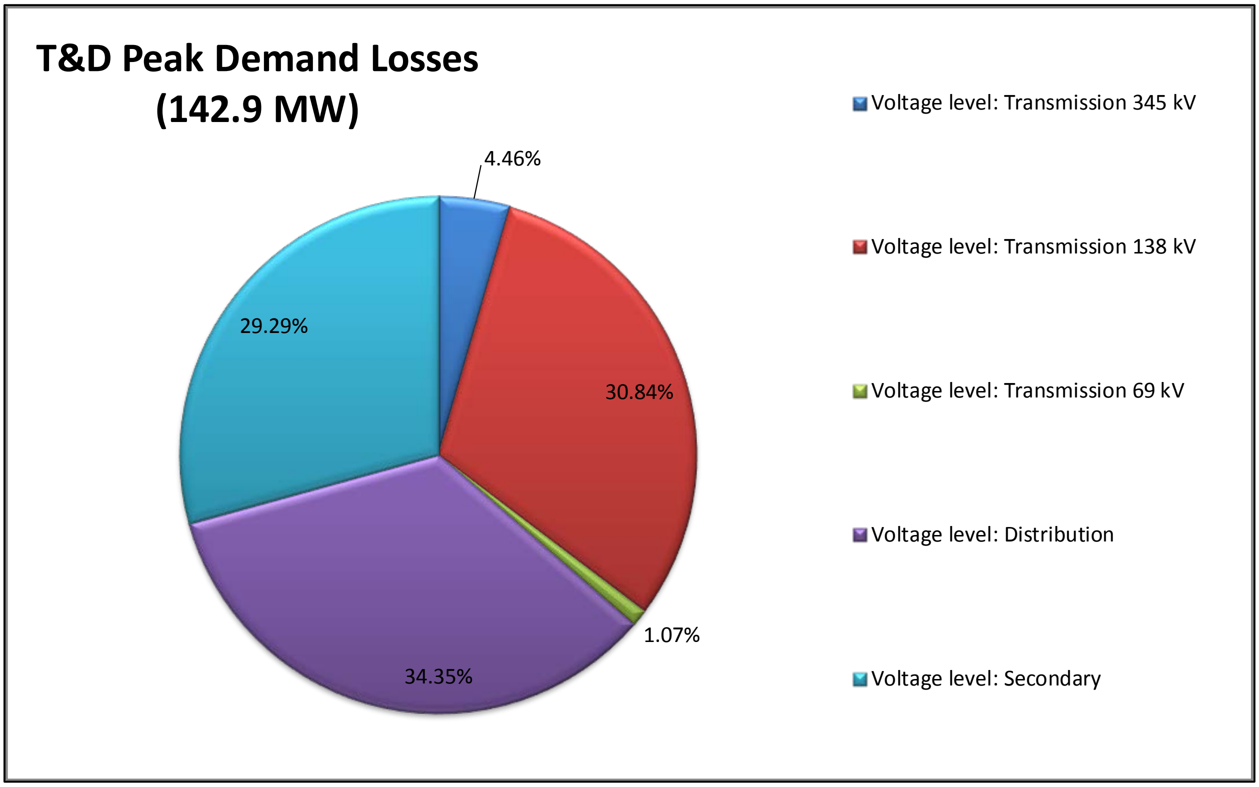


Figure 2. Calculated Demand Losses at Peak by Voltage Level

3 BASIS OF ANALYSIS

System losses are an unavoidable result of delivering power to electric utility customers, due to the physics of power flow and voltage transformation. In addition, losses can be broken into two groups: 1) constant losses, which are independent of the system loading; and 2) variable losses, which are dependent on system loading.

Constant losses consist primarily of transformer core losses, or no-load losses. The constant system losses included in this study were based on the name plate losses and the assumed time period of one year.
Variable losses include transmission and distribution line losses for the primary and secondary systems, and transformer winding, or load losses. The variable losses included in this study were based on the calculated losses at peak, the assumed time period of one year, and the Loss Factor.

The equation for the Loss Factor is as follows:

$Loss\ Factor = k * Load\ Factor + (1 - k) * Load\ Factor^2$

A value of 0.08 was assumed for the constant coefficient "k" for the Loss Factor calculations based on research published in IEEE Transactions on Power Systems on November 1988 using American and

Canadian utilities. The average annual Load Factor for the fiscal year 2018 of 55.28% was calculated based on the Austin Energy monthly system peak and energy purchases.

4 TRANSMISSION & DISTRIBUTION SYSTEM

Losses for the transmission and distribution systems were taken from the load flow results from the existing engineering models. The load flow results were based on the 2018 system peak, recorded in July. The transmission system is modeled in PTI Interactive Power System Simulator (PSSE™). The distribution system is modeled in FeederALL®.

The load flow results at the 2018 system peak provided data for transmission and distribution line losses, and substation transformer load losses. Substation transformer no-load losses were obtained from Austin Energy manufacturer test report summaries. If test reports were not available for a given transformer, impedances and no-load loss values were assumed based on similar sized transformers. The transmission and distribution line losses are presented in Exhibit B and Exhibit E, respectively. Transmission substation transformer load and no-load losses are presented in Exhibit C, while the distribution substation transformer losses are presented in Exhibit D.

5 DISTRIBUTION TRANSFORMERS

Inventory of the installed distribution transformer capacities and configurations was obtained from the existing GIS system. Distribution transformer specifications were based on a number of manufacturer test reports. If test reports were not available for a given transformer, impedances and no-load loss values were assumed based on similar sized transformers. A summary of the distribution transformer specifications used in the loss calculations is given in Exhibit G.

Loading for the distribution transformers was estimated using the total installed distribution transformer capacity and the estimated customer demand at the 2018 peak. Distribution transformer no-load and load losses are listed in Exhibit F.

6 SECONDARY SYSTEM

The ADMS database and GIS system together provided information related to the installed secondary conductor types and lengths for each of the following categories: service, secondary, and street lights. Losses in the secondary system were estimated based on the service category, average lengths, conductor types, and the estimated conductor loading.

The conductor loading was estimated based on the total service conductor capacity and the estimated customer demand at the 2018 peak. Secondary lines were assumed to be sized similar to service lines. Conductor loading for the secondary serving security and street lights was calculated based on the estimated lighting load, as provided by Austin Energy, and the total conductor capacity. Secondary line losses are presented in Exhibit H.

7 SECURITY AND STREET LIGHTS

Consumption estimates for security and street lights were provided by Austin Energy, which accounted for the light, the ballast, and other miscellaneous losses associated with each lamp size. The quantity of lights by size and type were also provided by Austin Energy based on information included in the existing GIS system. However, the total number of lights in the GIS system was greater than the number of lights billed for fiscal year 2009. As a result, the losses for security and street light losses were calculated based on the difference in the estimated annual energy consumption derived from the GIS data less the total lighting sales for fiscal year 2009. Security and street light losses are presented in Exhibit I.

EXHIBIT A: SYSTEM LOSS SUMMARY

AUSTIN ENERGY

Evaluation of T&D System Losses

Summary of T&D System Losses

SYSTEM LOSSES

	Austin Energy
2018 Annual Net Available for Sale (MWh)	13,936,605
2018 Annual Energy Sales (MWh)	13,409,802
ANNUAL SYSTEM LOSSES (MWh)	**526,803**
PERCENT SYSTEM LOSSES	**3.78%**

TYPE	ANNUAL ENERGY LOSSES (MWh)[2]	PERCENT OF AE ENERGY AVAILABLE	PERCENT OF TOTAL AE LOSSES	DEMAND LOSSES AT PEAK (MW)	PERCENT OF DEMAND AE LOSSES AT PEAK
Voltage Level: Transmission 345 kV	18,155	**0.13%**	3.45%	6.37	4.46%
Transmission Line Losses	18,155	**0.13%**	3.45%	6.37	4.46%
Transmission Substation Transformer Losses					
Core	0	**0.00%**	0.00%	0.00	0.00%
Winding	0	**0.00%**	0.00%	0.00	0.00%
Voltage Level: Transmission 138 kV	125,524	**0.90%**	23.83%	44.06	30.84%
Transmission Line Losses	111,582	**0.80%**	21.18%	39.15	27.40%
Transmission Substation Transformer Losses					
Core	8,798	**0.06%**	1.67%	1.55	1.08%
Winding	5,145	**0.04%**	0.98%	3.36	2.35%
Voltage Level: Transmission 69 kV	5,534	**0.04%**	1.05%	1.53	1.07%
Transmission Line Losses	3,278	**0.02%**	0.62%	1.15	0.80%
Transmission Substation Transformer Losses					
Core	1,743	**0.01%**	0.33%	0.20	0.14%
Winding	513	**0.00%**	0.10%	0.18	0.13%
Voltage Level: Distribution	155,986	**1.12%**	29.61%	49.08	34.35%
Distribution Line Losses	102,094	**0.73%**	19.38%	35.82	25.07%
Distribution Substation Transformer Losses					
Core	23,882	**0.17%**	4.53%	2.73	1.91%
Winding	30,010	**0.22%**	5.70%	10.53	7.37%
Voltage Level: Secondary	222,375	**1.60%**	42.21%	41.85	29.29%
Distribution Transformer Losses					
Core	149,958	**1.08%**	28.47%	17.12	11.98%
Winding	22,127	**0.16%**	4.20%	7.76	5.43%
Service and Secondary Line Losses	48,360	**0.35%**	9.18%	16.97	11.88%
Street & Security Lights[(1)(3)]	1,931	**0.01%**	0.37%	0.00	0.00%
Metering Inaccuracies	(772)	**-0.01%**	-0.15%	0.00	0.00%
TOTALS	526,803	**3.78%**	100.00%	142.89	100.00%

Notes:
(1) Street and Security Light losses are the difference in billed kWh and total kWh for all lights
(2) Annual Energy Losses were determined using the following equations:
Annual Energy Losses = Peak Demand (kW) * Time (hrs) * Loss Factor
Loss Factor = k * Load Factor + (1 - k) * (Load Factor)^2
"k" constant 0.08
Load Factor 55.28%
(3) Street and Security Light were off at the recorded peak
(4) GSU's results are categorized by the high side voltage, all other transformer results are categorized by low side voltage

EXHIBIT B: TRANSMISSION LINE LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Transmission Line Losses

TRANSMISSION VOLTAGE (kV)	MILES OF LINE [1]	DEMAND LOSSES AT 2018 PEAK (MW)[2]	ANNUAL ENERGY LOSSES (MWh)
69	26.1	1,150	3,277,642
138	321.5	39,150	111,582,322
345	276.2	6,370	18,155,285
TOTALS	623.8	46,670	133,015,248

Notes:
(1) Transmission line length from AE Transmission Line Database
(2) Peak losses extracted from PSS/E system model

EXHIBIT C: TRANSMISSION TRANSFORMER LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Transmission Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER VOTLAGE	TRANSFORMER BASE RATING (MVA)	TRANSFORMER NO-LOAD LOSSES (kW) (1)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
NL AT1	138/69 kV	220	35.6	311,462	30	85,504
KB AT1	138/69 kV	220	51.8	453,768	80	228,010
SP-AT1 (McNeil)	138/69 kV	220	61.6	539,861	40	114,005
PE-AT1	138/69 kV	220	50.0	437,912	30	85,504
DL AT1	345/138 kV	672	146.7	1,285,092	380	1,083,047
GF AT1	345/138 kV	480	90.0	788,400	150	427,518
GF AT2	345/138 kV	480	91.7	803,292	180	513,022
LY AT1	345/138 kV	480	124.9	1,093,861	320	912,039
LY AT2	345/138 kV	480	98.1	859,356	170	484,521
AU AT1	345/138 kV	480	118.0	1,033,855	150	427,518
AU AT2	345/138 kV	480	121.2	1,061,975	130	370,516
DP MT1	22.8/138 kV	420	219.5	680,326	540	544,647
DP MT2	22.8/138 kV	470	232.6	599,333	780	653,986
DP MPT1(5)	13.8/138 kV	139	51.0	79,560	70	35,529
DP MPT2(5)	13.8/138 kV	139	51.0	62,220	70	27,785
SA MPT1(6)	13.8/138 kV	130	52.0	95,784	280	167,806
SA MPT3(7)	13.8/138 kV	130	50.0	93,300	280	169,992
SA MPT6(8)	13.8/138 kV	150	50.8	93,116	90	53,674
SA AT1(9)	18.0/138 kV	480	199.2	1,453,164	150	356,021
345 kV TOTALS		0	0.0	0	0	0
138 kV TOTALS(10), (11)		4,938	1,550.0	8,797,542	3,360	5,144,576
69 kV TOTALS(10)		880	199.0	1,743,003	180	513,022
TOTALS		6,490	1,895.6	11,825,638	3,920	6,740,645

Notes:
(1) From Austin Energy test reports
(2) Annual No-Load Energy Losses is based on calculated demand losses times 8760 hours.
(3) Calculated in PSS/E model with 2018 peak load flows
(4) Annual Load Energy Losses is based on transformer load losses, 8760 hours, and a loss factor calculated from the annual load factor
(5) No-Load Demand Losses are estimated to be the same as Sandhill Transformers of similar size
(6) Losses for SANDH_G1 and SANDH_G2
(7) Losses for SANDH_G3 and SANDH_G4
(8) Losses for SANDH_G6 and SANDH_G7
(9) Losses for SANDHG5A and SANDHG5C
(10) GSU's results are categorized by the high side voltage, all other transformer results are categorized by low side voltage
(11) GSU's losses scaled by % runtime in 2018

EXHIBIT D: SUBSTATION TRANSFORMER LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2018 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
AD123	30	11,052	16.0	140,160	24.0	68,460
AD456	30	13,802	16.0	140,072	38.1	108,704
AG123	30	14,251	14.1	123,866	24.4	69,629
AG456	30	22,130	14.0	122,465	97.5	277,916
BAL TX1 (5)(6)	25	17	14.0	122,640	13.4	38,163
BAL TX2 (5)(6)	25	9,623	14.0	122,640	13.4	38,163
BA012	30	19,789	13.0	113,530	86.6	246,906
BA123	30	15,117	9.4	82,344	55.1	157,070
BA456	30	18,464	32.6	285,576	77.9	222,053
BA789	30	11,645	15.4	134,816	24.0	68,317
BC123	30	11,365	26.3	230,476	38.8	110,613
BC456	30	11,365	18.9	165,914	23.2	66,237
BC789	30	13,323	12.3	107,923	37.2	106,139
BE123	30	10,341	13.8	120,976	18.1	51,530
BE456	30	12,767	10.7	93,382	36.6	104,201
BL123	30	26,539	13.9	121,764	141.5	403,150
BL456	30	16,673	16.3	142,788	49.0	139,628
BL789	30	23,995	12.6	110,551	120.7	343,953
BR123	70	19,298	49.6	434,496	34.1	97,132
BR456	70	18,465	50.7	444,307	56.8	161,858
BR789	70	19,588	26.5	232,140	28.2	80,373
BU123	30	22,293	13.4	117,209	111.4	317,618
BU456	30	15,192	13.2	115,282	48.5	138,316
BU789	30	25,725	29.0	254,040	298.3	850,249
BW123	50	2,329	20.6	180,456	0.5	1,454
BW456	50	1,166	21.1	184,836	0.1	285
CC123	30	22,405	14.4	126,144	96.5	275,122
CC456	30	8,256	10.1	88,301	15.9	45,374
CC789	30	5,716	12.3	107,836	5.3	14,963
CA123	30	19,178	13.1	114,668	71.2	202,929
CA456	30	24,965	13.0	113,705	121.8	347,088
CF123	30	20,310	15.9	138,846	82.1	233,938
CF456	30	22,232	12.0	105,120	96.4	274,752
CF789	30	15,561	12.8	111,690	50.2	143,019
CL012	30	20,203	13.6	119,311	46.9	133,585
CL123	30	20,490	14.3	124,918	50.4	143,561
CL456	30	25,077	13.9	121,764	123.9	353,102
CL789	30	15,582	13.6	118,698	30.2	86,102
CM123	30	17,541	9.2	80,942	69.2	197,257
CM456	30	6,113	10.5	91,892	8.1	23,000
CM789	30	18,263	13.3	116,070	66.9	190,559
CM101112	30	7,822	13.8	120,538	7.4	21,205
DE123	30	9,870	13.6	119,048	27.6	78,521
DE456	50	24,045	18.5	162,060	74.4	212,078
DE789	50	24,144	18.6	162,848	59.5	169,468
DE101112	50	17,554	19.6	171,433	22.5	64,042
DE131415	50	17,504	19.0	166,002	31.3	89,123
DE161718	67	22,572	25.9	226,534	28.3	80,516
DE192021	67	22,503	25.6	223,818	32.0	91,147
DE222324	30	26,627	14.4	125,881	96.2	274,239
DE2526	30	15,176	14.4	125,881	30.2	85,931

EXHIBIT D: SUBSTATION TRANSFORMER LOSSES (PAGE 2)

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2018 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
DG123	30	9,219	14.2	124,742	10.2	29,157
DG456	30	17,420	13.4	117,734	61.2	174,542
DL123	30	10,896	17.9	156,716	21.8	62,104
EB012	50	4,861	20.7	181,157	5.7	16,331
EB123	50	(41)	23.0	201,830	0.0	0
EB456	50	4,788	22.0	192,720	5.8	16,388
EB789	50	24,792	22.0	192,720	133.2	379,665
ER123	30	1,924	12.2	106,609	0.5	1,311
FI123	30	22,435	12.9	112,654	95.0	270,648
FI456	30	15,751	13.9	121,764	48.3	137,718
FV123	30	20,374	14.2	124,042	73.7	210,083
FV456	30	18,802	18.0	157,417	58.3	166,276
GR123	30	5,074	15.2	133,327	3.4	9,662
GR456	30	3,757	12.5	109,325	2.7	7,553
GR789	30	25,891	36.1	316,236	146.7	418,028
HC012	30	25,453	12.1	106,259	144.7	412,327
HC123	30	28,272	32.5	284,350	197.3	562,443
HC456	30	23,745	28.8	252,288	118.8	338,452
HC789	30	25,512	11.5	100,740	139.0	396,025
HL123	30	21,273	16.1	140,861	82.0	233,710
HL456	30	24,687	14.2	124,392	121.1	345,064
HM012	30	17,031	13.7	120,100	28.5	81,286
HM123	30	18,561	28.9	253,339	68.3	194,606
HM456	30	23,350	25.5	223,643	162.8	463,972
HM789	30	14,621	13.3	116,420	39.2	111,839
HV123	30	21,757	13.1	114,668	102.6	292,337
HV456	30	27,606	9.1	79,804	161.2	459,354
JE123	30	21,825	28.7	251,412	116.8	332,866
JE456	30	16,779	13.4	117,034	51.8	147,608
JV123	30	25,822	15.3	133,678	135.4	385,935
JV456	30	17,939	9.4	82,256	71.5	203,727
JV789	30	18,370	13.0	114,230	70.8	201,817
JL123	30	17,607	16.9	147,956	40.3	114,860
JL456	30	6,416	17.0	149,095	5.0	14,251
KB123	30	16,478	16.6	144,978	52.1	148,491
KB456	30	22,108	13.8	120,888	101.3	288,575
KL1234	30	18,650	17.3	151,636	53.9	153,536
KL5678	30	19,591	17.4	152,774	50.9	145,014
LS123	30	19,144	14.1	123,516	78.5	223,849
LS456	30	15,580	15.0	131,400	54.2	154,363
LW123	30	18,877	15.3	133,678	61.8	176,223
LW456	30	23,266	9.4	82,432	120.5	343,554
MC012	30	8,198	13.6	118,698	13.9	39,588
MC123	30	15,980	12.4	108,361	33.2	94,710
MC456	30	17,664	28.8	251,850	72.2	205,893
MC789	30	15,166	15.6	136,919	47.4	135,210
MP123	30	18,724	15.0	131,400	76.2	217,037
MP456	30	20,944	13.0	113,880	89.3	254,402
MP789	30	17,533	11.5	100,390	52.4	149,403
MT123	30	7,625	16.0	140,072	11.2	31,978
MT012	30	10,648	10.9	95,572	23.0	65,524

EXHIBIT D: SUBSTATION TRANSFORMER LOSSES (PAGE 3)

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2018 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
MU123	30	7,980	14.4	126,056	7.6	21,746
MU456	30	8,494	12.3	108,098	9.1	25,993
NL012	30	19,464	11.3	98,988	66.8	190,360
NL123	20	9,673	15.9	138,934	27.2	77,523
NL345	30	24,123	9.9	86,461	119.6	340,989
NL789	20	6,024	16.3	142,438	24.3	69,315
NW123	30	22,569	14.2	123,954	109.0	310,549
NW456	30	4,223	16.7	146,642	3.3	9,263
OC123	30	4,396	13.0	113,968	4.1	11,657
OC456	30	0	11.6	101,266	0.0	0
OH123	30	15,116	12.1	105,996	52.0	148,121
OH456	30	19,059	11.8	103,368	79.3	225,872
OH789	30	21,594	13.4	117,734	96.2	274,096
PE1234	30	23,433	14.0	122,903	118.9	338,737
PE5678	30	25,747	14.0	122,903	145.5	414,579
PL123	30	26,716	14.1	123,253	128.6	366,469
PL789	50	20,161	20.9	183,084	56.6	161,374
PL101112	30	21,491	16.2	141,912	79.2	225,844
PL131415	30	4,250	14.1	123,428	2.2	6,128
RP123	20	396	14.8	129,998	0.1	228
RP789	30	17,417	14.8	129,560	36.3	103,573
SK123	30	9,236	28.6	250,448	19.9	56,632
SK456	30	23,276	12.6	110,551	116.3	331,384
SL123	30	25,975	14.4	125,706	126.5	360,455
SL456	30	24,754	28.5	249,222	146.3	416,831
SL789	30	23,484	14.8	129,560	110.1	313,884
SP123	30	18,073	13.2	115,369	44.0	125,462
SP789	30	21,930	13.4	117,647	107.9	307,443
SP012	30	22,445	13.9	121,676	108.2	308,241
SP345	70	28,121	20.1	175,726	74.1	211,308
SP678	70	28,004	20.0	175,200	62.7	178,646
SN-NT1	50	0	15.0	131,400	0.0	0
SN-NT2	50	23,056	15.0	131,400	47.8	136,207
SR123	30	17,538	12.5	109,325	41.9	119,449
ST123	30	16,411	14.2	124,742	48.4	137,974
ST456	30	12,624	10.5	91,630	27.6	78,749
ST789	30	18,677	14.7	129,035	75.0	213,731
SU123	30	20,083	11.6	101,791	80.6	229,805
SU456	30	19,448	12.1	105,558	73.4	209,171
SU789	30	9,652	14.0	122,815	12.1	34,486
SU012	30	7,853	14.7	128,684	7.4	21,034
SU345	30	23,868	13.1	115,019	120.8	344,152
SW123	30	24,113	16.0	140,160	109.9	313,286
SW456	30	23,448	17.3	151,548	100.1	285,155
SW789	30	21,416	12.6	110,376	90.5	258,050
TP123	30	20,630	9.9	86,724	82.6	235,392
TP456	30	17,075	10.8	94,170	58.5	166,818
TP789	30	20,066	15.8	138,671	74.7	212,933
TR123	30	25,964	13.1	114,581	176.3	502,363
TR456	30	11,468	13.4	117,734	30.8	87,641
TR789	30	19,891	12.9	113,004	86.4	246,194

EXHIBIT D: SUBSTATION TRANSFORMER LOSSES (PAGE 4)

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2018 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
VE123	50	0	15.5	135,430	0.0	0
WA123	30	16,702	25.6	224,431	84.3	240,351
WA456	30	7,675	25.5	223,292	17.0	48,452
WA789	30	6,974	16.1	140,773	9.2	26,335
WB123	50	3,233	15.0	131,312	0.8	2,252
WB456	50	3,221	21.0	183,522	0.8	2,309
WC012	30	15,324	11.6	101,966	44.3	126,175
WC789	30	14,429	9.9	86,286	55.7	158,695
WI012	30	14,869	11.5	100,565	39.1	111,440
WI123	40	22,578	13.6	119,136	100.9	287,634
WI456	40	28,787	15.4	135,079	156.4	445,873
WI789	30	17,333	15.4	135,079	54.8	156,073
WL123	30	13,387	21.6	189,216	38.0	108,305
WL456	30	23,343	12.8	111,778	69.7	198,568
WL789	30	18,502	13.1	114,756	75.2	214,244
TOTALS	530	206,359	243.5	2,132,622	746.2	2,126,705

Notes:
(1) From Austin Energy test reports
(2) Annual No-Load Energy Losses is based on calculated demand losses times 8760 hours.
(3) Calculated in Feederall model with 2018 peak load flows
(4) Annual Load Energy Losses is based on transformer load losses, 8760 hours, and a loss factor calculated from the annual load factor
(5) No-Load Loss values were estimated based on the average No-Load Loss of th 30 MVA Transformers
(6) Load Loss values were estimated based on 30 MVA Transformers of simlar loading
(7) Units with no No-Load Losses are de-energized or out of service

EXHIBIT E: DISTRIBUTION LINE LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Primary Distribution Line Losses

DISTRIBUTION VOLTAGE (kV)	LENGTH OF LINE (Miles)	DEMAND LOSSES [1] AT 2018 PEAK (kW)	ANNUAL ENERGY LOSSES (kWh)
12.5[2]	5,803.0	35,821.0	102,094,262
TOTALS	5,803.0	35,821.0	102,094,262

Notes:
(1) Peak losses extracted from Feederall model

EXHIBIT F: DISTRIBUTION TRANSFORMER LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Transformer Losses

LOCATION	TOTAL NO-LOAD LOSSES (kW)	TOTAL LOAD LOSSES (kW)	NUMBER OF XFMRS	TOTAL XFMR kVA	TOTAL ANNUAL ENERGY NO-LOAD LOSS (kWh)	TOTAL ANNUAL ENERGY LOAD LOSS (kWh)
Distribution Transformers	17,118	7,763	84,377	7,485,681	149,957,879	22,126,624
TOTALS	17,118	7,763	84,377	7,485,681	149,957,879	22,126,624

Notes:

(1) Losses were estimated for each distribution transformer size based on the manufacturer test reports for similar sized transformers
(2) Transformer loading based on customer sales and total transformer capacity
(3) Results excludes primary metered transformers
(4) Calculated Transformer Loading Percentage 36.86%

EXHIBIT G: DISTRIBUTION TRANSFORMER SPECIFICATIONS

Phasing	VOLTAGE (kV)	Transformer KVA	Test Report NLL (KW)	Test Report %R
1ph	12.5	1.5	0.008	1.52%
1ph	12.5	3	0.017	1.52%
1ph	12.5	3.5	0.020	1.52%
1ph	12.5	5	0.030	1.52%
1ph	12.5	10	0.045	1.26%
1ph	12.5	15	0.059	1.13%
3ph	12.5	15	0.069	0.78%
1ph	12.5	25	0.086	0.99%
3ph	12.5	25	0.106	0.75%
1ph	12.5	37.5	0.120	0.93%
3ph	12.5	37.5	0.109	0.55%
1ph	12.5	50	0.148	0.86%
3ph	12.5	50	0.156	0.59%
1ph	12.5	75	0.210	0.83%
3ph	12.5	75	0.210	0.52%
1ph	12.5	100	0.261	0.36%
3ph	12.5	100	0.243	0.32%
3ph	12.5	112.5	0.280	0.33%
1ph	12.5	125	0.282	0.30%
3ph	12.5	150	0.345	0.31%
1ph	12.5	150	0.345	0.31%
1ph	12.5	167	0.305	0.19%
3ph	12.5	167	0.303	0.20%
1ph	12.5	175	0.321	0.19%
1ph	12.5	200	0.373	0.20%
3ph	12.5	225	0.428	0.20%
1ph	12.5	225	0.428	0.20%
1ph	12.5	250	0.547	0.14%
3ph	12.5	250	0.501	0.16%
3ph	12.5	300	0.570	0.15%
1ph	12.5	300	0.570	0.15%
3ph	12.5	333	0.572	0.07%
1ph	12.5	333	0.664	0.07%
3ph	12.5	500	0.850	0.07%
1ph	12.5	500	0.850	0.07%
3ph	12.5	750	1.200	0.05%
1ph	12.5	750	1.200	0.05%
3ph	12.5	1000	1.300	0.03%
3ph	12.5	1500	2.100	0.02%
1ph	12.5	1500	2.100	0.02%
3ph	12.5	2000	2.600	0.02%
3ph	12.5	2500	2.500	0.01%
3ph	12.5	5000	5.000	0.01%

EXHIBIT H: SECONDARY LINE LOSSES

AUSTIN ENERGY

Evaluation of System Losses

Estimated Service Line Losses

Type	MILES OF CONDUCTOR	PERCENT CONDUCTOR PEAK LOADING/CAPACITY [1]	PEAK DEMAND LOSS (kW)	ANNUAL ENERGY LOSSES (kWh)
Secondary Conductor	5,896	31.9%	16,964	48,350,649
Streetlight Conductor	1,626	1.5%	6.8	9,749
TOTAL	7,522		16,971	48,360,398

Notes

(1) Conductor loading percentage is as follows:

Secondary Conductor = (Annual Energy Sales (kWh)-Streetlight Annual Energy Sales (kWh)) / (Time * Load Factor) / Conductor Capacity (kVA)

Streetlight Conductor = (Streetlight Annual Energy Sales (kWh) / (Time * Load Factor)) / Conductor Capacity (kVA)

EXHIBIT I: SECURITY AND STREETLIGHT LOSSES

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Street & Security Light Losses

SECURITY & STREET LIGHT SIZES	ASSUMED USAGE (WATTS)	NUMBER OF LIGHTS FROM GIS	ASSUMED DEMAND (kW)	ANNUAL ENERGY CONSUMPTION (kWh)
30 Watt	33	1	0.0	145
51 Watt	56	17	1.0	4,177
70 Watt	77	64	4.9	21,585
75 Watt	83	8,829	728.4	3,190,359
80 Watt	88	26	2.3	10,021
100 Watt	110	30,194	3,321.3	14,547,469
150 Watt	165	521	86.0	376,527
175 Watt	193	2,197	422.9	1,852,401
250 Watt	275	18,157	4,993.2	21,870,107
400 Watt	440	4,937	2,172.3	9,514,586
1000 Watt	1,100	87	95.7	419,166
1500 Watt	1,650	12	19.8	86,724
TOTALS		65,042	11,847.8	51,893,266
TOTAL BILLED kWh				49,962,729
UNACCOUNTED FOR LIGHT CONSUMPTION				1,930,537

Notes:
(1) Estimated 12 hours of operation per day

EXHIBIT J: SYSTEM LOSSES PIE CHARTS

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Energy Losses by Voltage

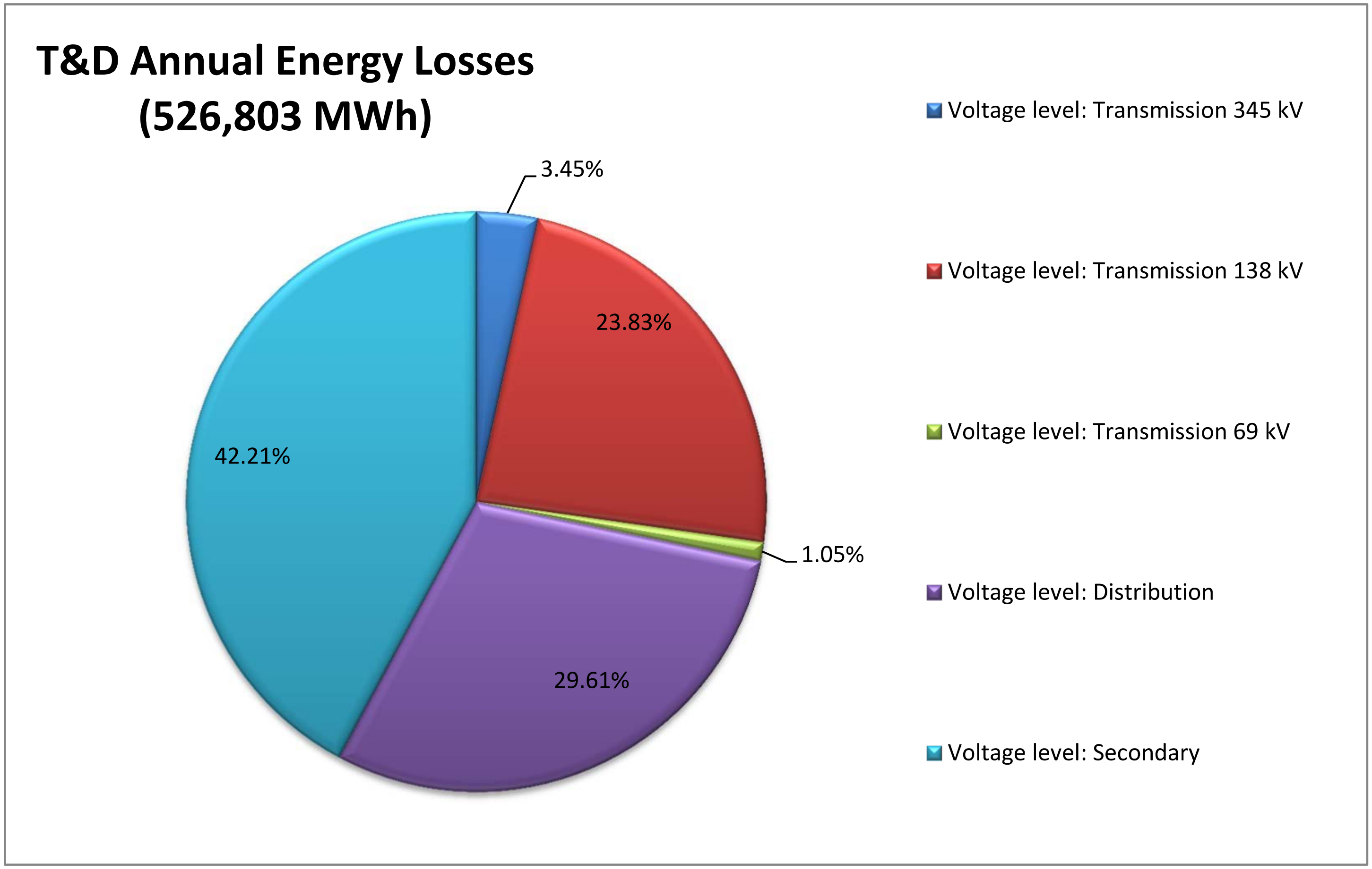


EXHIBIT J: SYSTEM LOSSES PIE CHARTS (page 2)

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Energy Losses by Equipment Type

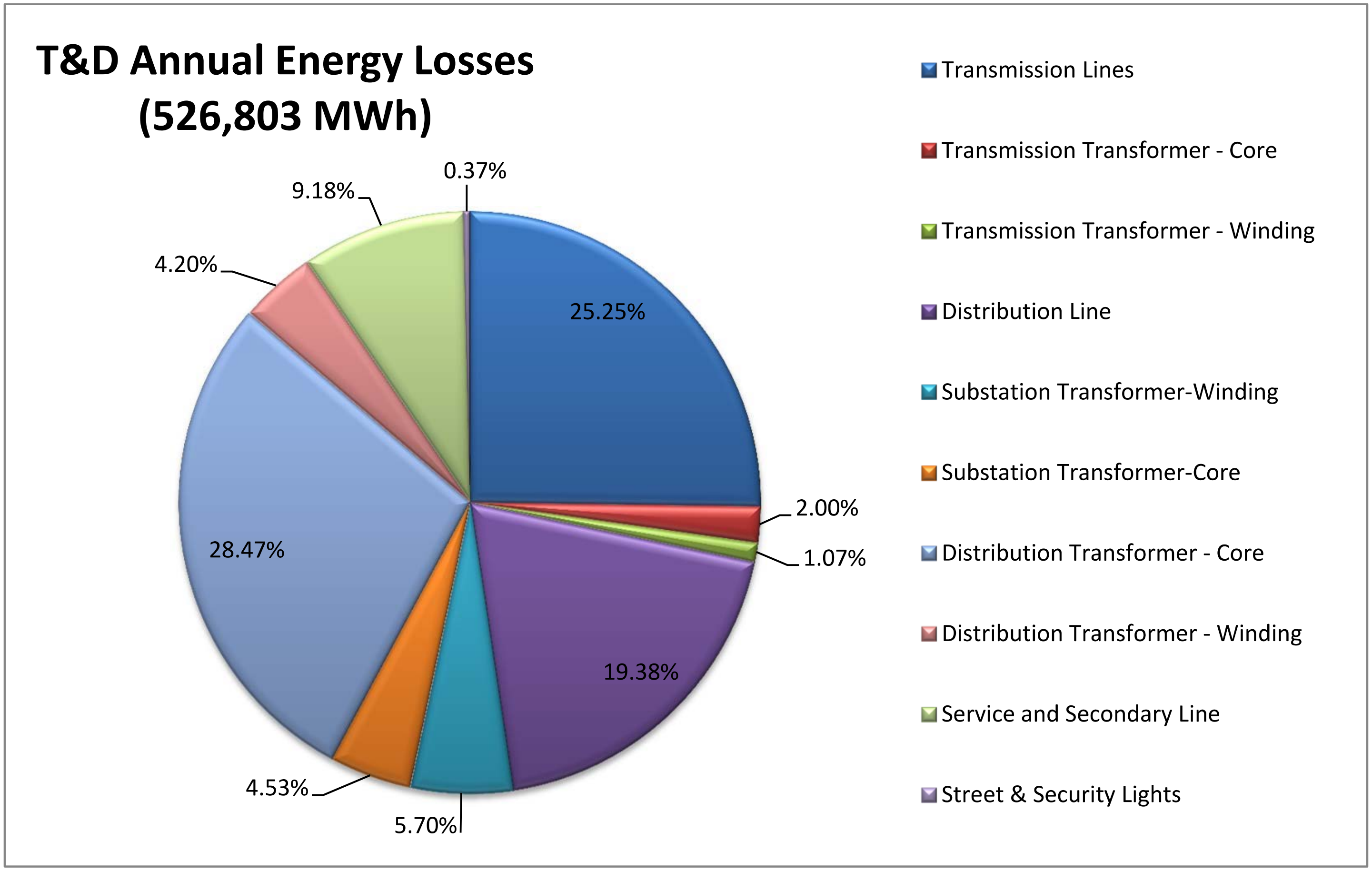


EXHIBIT J: SYSTEM LOSSES PIE CHARTS (PAGE 3)

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Demand Losses by Voltage

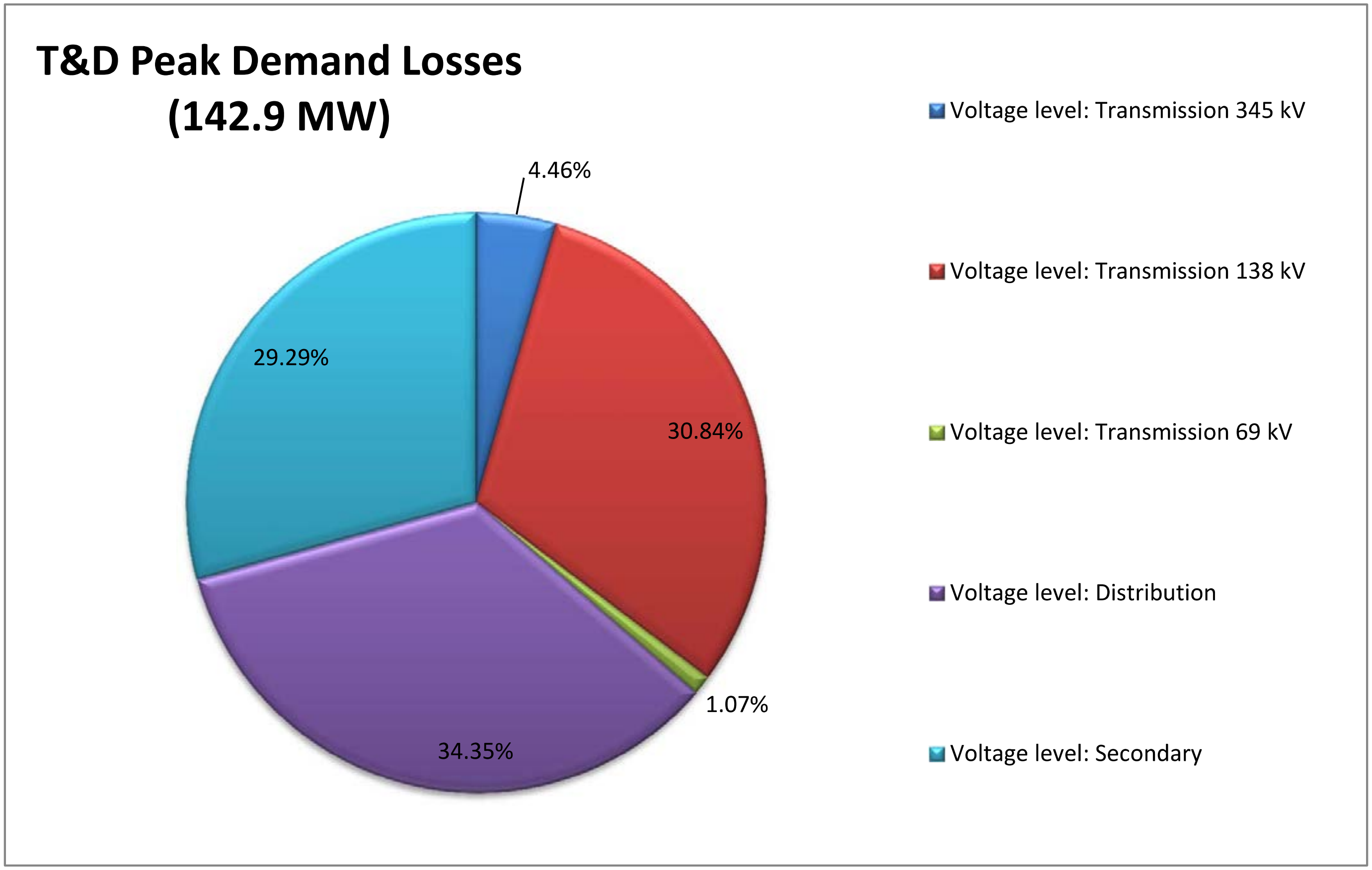
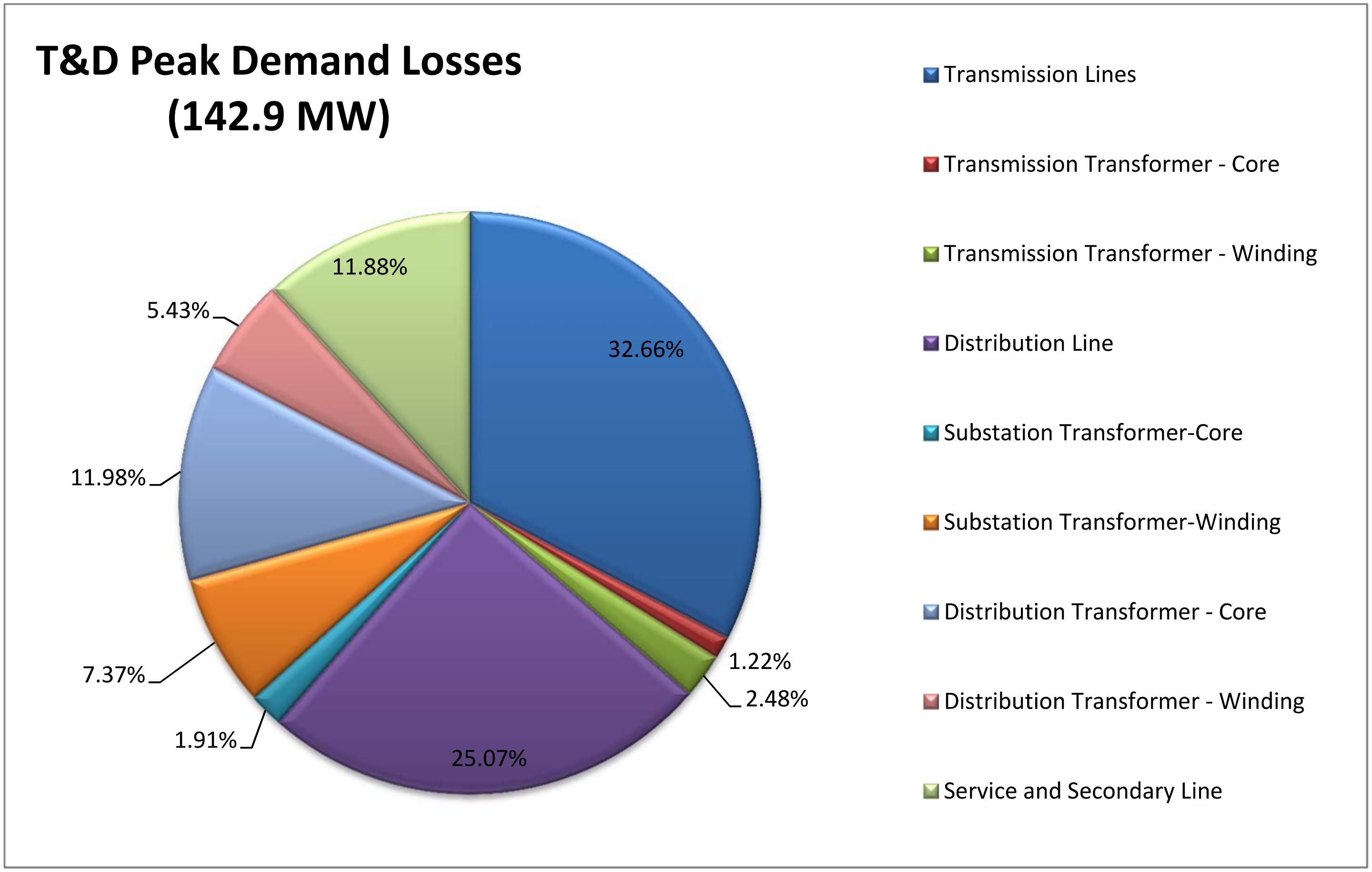


EXHIBIT J: SYSTEM LOSSES PIE CHARTS (PAGE 4)

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Demand Losses by Equipment Type



DOCUMENT CHANGE AND REVIEW HISTORY

The change history below reflects changes to the contents or format of this document.

Change History:

Date	Author(s)	Description	Version	Company
5/2/19	Reza Ebrahimian	Final Report Version 1.0	1.0	Austin Energy

Review Log:

Date	Reviewed by	Version	Company