AUSTIN ENERGY TARIFF PACKAGE UPDATE—2022 RATE REVIEW	§ § § § § § §	**BEFORE THE** **CITY OF AUSTIN IMPARTIAL** **HEARING EXAMINER**

INITIAL PRESENTATION

OF

DAVID J. EFFRON

ON BEHALF OF THE

INDEPENDENT CONSUMER ADVOCATE

JUNE 22, 2022

AUSTIN ENERGY- 2022 RATE REVIEW
DIRECT TESTIMONY OF DAVID J. EFFRON
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SCHEDULES DJE-1, DJE-2, and DJE-3

AE RFI responses to ICA 2-5 (without appendices), ICA 2-6, ICA 2-8, ICA 2-9, ICA 2-11, ICA 4-4, ICA 4-5, ICA 4-6, and ICA TC 2-19.

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 12 Pond Path, North Hampton, New Hampshire, 03862.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes over thirty years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, gas, telephone, and water filings in different jurisdictions. Pursuant to those analyses I have prepared testimony, assisted attorneys in case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over three hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Missouri, Nevada, New Jersey, New York, North

Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Vermont, Virginia, and Washington.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

II. PURPOSE OF TESTIMONY AND SUMMARY OF CONCLUSIONS

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Independent Consumer Advocate (“ICA").

Q. What is the purpose of your testimony?

A. Austin Energy ("AE") has requested increases in base rates for electric service and has presented revenue requirement calculations to support the requested rate increases. In this testimony, I address certain issues in the determination of AE's calculation of its revenue deficiency under the base rates presently in effect, and I propose certain adjustments to AE's calculation of its pro forma test year revenue requirement based on the issues that I address. I have also incorporated the effect of certain adjustments addressed by ICA Witness Clarence Johnson into my calculation of the AE's present revenue deficiency.

Q. Can you summarize your calculation of the AE's present revenue deficiency?

A. Yes. I have summarized my calculation of AE's revenue deficiency on my Schedule DJE-1. AE has calculated a base rate revenue deficiency of $48,219,749. The revenue requirement adjustments on my Schedule DJE-1 total $41,691,494. With these adjustments, I have calculated a revenue deficiency of $6,528,255.

The calculation of AE's revenue deficiency in this testimony is based on issues that I have identified and the issues addressed by Mr. Johnson that I have incorporated. I have not reviewed any issues addressed by other intervenors and take no position on those issues. At the time of the preparation of this testimony, certain of the ICA's requests for information were outstanding. I reserve the right to amend or modify my testimony based on AE's responses to those outstanding requests.

III. REVENUE REQUIREMENT ISSUES

A. NON-NUCLEAR DECOMMISSIONING

Q. Did AE include an annual contribution to the non-nuclear decommissioning reserve in its revenue requirement?

A. Yes. As can be seen on AE Work Paper C.-3.6, AE has included an annual contribution to the non-nuclear decommissioning reserve of $8,000,000 in its revenue requirement. The annual contribution is intended to fund the cost of demolition and removal of non-nuclear generation plants at the end of their useful lives.

Q. Did AE provide support for the $8,000,000 annual contribution?

A. AE was asked to provide supporting documentation for the $8,000,000 annual contribution in ICA RFI 2-5 (attached). In its response, AE stated that its financial policies require that funding for decommissioning non-nuclear generation plants be set aside over a minimum of four years prior to the expected plant closure. AE also provided a study prepared by an outside consultant in support of the estimated cost of decommissioning its non-nuclear plants. However, there are no workpapers or calculations to show how the financial policies or the cost study estimates result in an annual contribution of $8,000,000. However, as explained below, AE has been contributing $8,000,000 per year to the decommissioning reserve since the time of its last rate case.

Q. Based on your analysis, is $8,000,000 the appropriate amount to include in AE's prospective revenue requirement as the annual contribution to the non-nuclear decommissioning reserve?

A. No. Based on the estimated cost of decommissioning shown in the study provided by AE and what AE has already recovered in rates for non-nuclear decommissioning, the $8,000,000 is well in excess of the appropriate prospective annual allowance for non-nuclear decommissioning.

Q. What is the estimated cost of decommissioning AE's non-nuclear generation plants?

A. I have summarized the estimated costs of decommissioning each of the non-nuclear generation plants on Schedule DJE-2. The decommissioning study presents a "Low Range Estimate" and a "High Range Estimate" for each of the plants, which I show on my schedule. I have calculated a mid-point estimate, based on the average of the "Low Range Estimates" and "High Range Estimates" shown in the study. As far as I can determine, nothing in the study implies that the "Low Range Estimates" are less likely than the "High Range Estimates," or vice-versa. I believe that the mid-point, a total approximately $62.8 million for three generation plants in the decommissioning study, is the best unbiased estimate and is, therefore, the appropriate starting point for the purpose of determining the appropriate annual contribution to the decommissioning reserve.

Q. Did AE also include a non-nuclear decommissioning expense in its revenue requirement in its 2016 rate case?

A. Yes. AE requested a nuclear decommissioning allowance of approximately $19.4 million in that case. Based on the response to ICA TC 2-19, "at the conclusion of the 2016 Rate Review, Austin Energy was only allowed $8 million annually toward this obligation and has continued this level of funding since that time."[1] The rates established in the 2016 Rate Review will have been in effect for six years when the rates in the present case go into effect. Thus, AE will have recovered in rates and funded $48 million (that is, 6 years times $8 million) of the non-nuclear decommissioning reserve as of January 1, 2023. At that time, approximately $14.8 million of the estimated total decommissioning costs of $62.8 million will remain to be recovered (Schedule DJE-2).

Q. How should the remaining $14.8 million be recovered?

A. I recommend that the $14.8 million be recovered over the remaining lives of the non-nuclear generation plants. On my Schedule DJE-2, I have calculated that the average remaining life, weighted by the estimated decommissioning cost of the plants, is approximately 9.4 years. This results in annual non-nuclear decommissioning expense of $1,570,000.

Q. What do you recommend?

A. To be conservative, I recommend that my calculated non-nuclear decommissioning expense of $1,570,000 be rounded up to $2,000,000 and that this amount be included in

[1] This appears to be the basis for the $8 million per year in the present case, as well.

the test year revenue requirement. My proposed adjustment to the non-nuclear decommissioning expense reduces the test year AE revenue requirement by $6,000,000.

B. SOUTH TEXAS PROJECT O&M EXPENSE

Q. Has AE adjusted the actual FY 2021 South Texas Project ("STP") operation and maintenance ("O&M") expense included in its test year revenue requirement?

A. Yes. This adjustment is shown on AE Work Paper WP D-1.2.1. It is an increase to the actual FY 2012 O&M of $596,244. As explained on WP D-1.2.1, "Maintenance schedule for STP includes periodic over-haul expenses every third year and, thus, a three-year average is necessary to capture these recurring, but uneven, contract costs." In addition, based on the response to ICA 2-6, "The adjustment in the Rate Filing Package for non-cash decommissioning expense in FERC 524 was intended to remove the non-cash amount from the Test Year." This response also noted that "The adjustment will be corrected."

Q. Have you calculated the necessary correction to the adjustment to the STP O&M expense?

A. Yes. As described by AE, the purpose of the adjustment to reflect a three-year average for STP O&M expenses, with non-cash amounts removed.

I have calculated the necessary adjustment on my Schedule DJE-3. I have begun with the actual expenses for Fiscal Years 2019, 2020, and 2021 and then eliminated the effect of non-cash accruals for each of those years. The three-year average of STP O&M expense, with non-cash amounts removed, is $52,089,399. This is $8,728,527 less than the $60,817,926 of expenses actually recorded in FY 2021. Therefore, instead of an increase of $596,244, the appropriate adjustment should be a reduction of $8,728,527, and the pro forma test year expenses should be reduced by $9,324,751.[2]

Q. What is the effect of the correction to the adjustment to the FY 2021 STP O&M expense on the AE revenue requirement?

A. The effect of the correction is to reduce the AE revenue requirement by $9,324,751 (Schedule DJE-1).

C. RATE CASE EXPENSE

Q. Did AE include the cost of the present rate case in its revenue requirement?

A. Yes. AE has included rate case expense of $597,000 in its revenue requirement. This amount was calculated by normalizing total estimated rate case costs of $1,791,000 over three years (AE Work Paper WP D-1.2.7).

Q. Are you proposing to modify the annual rate case expense included in the AE revenue requirement?

A. Yes. The last AE rate case was six years ago. Therefore, I believe a normalization period of at least five years would be more appropriate. Normalizing total rate case costs of $1,791,000 over five years rather than over three years reduces the annual rate case expense by $238,800 (Schedule DJE-1).

[2] This correction is equal to the effect of changing the "Non-Cash Adjustment to FY 2021" of $4, 662,375 on AE Work Paper WP D-1.2.1 from a positive to a negative.

D. HEAVY EQUIPMENT LEASES

Q. What as the actual expense incurred for the lease of heavy equipment in Fiscal Year 2021?

A. The actual expense in Fiscal Year 2021 was $5,338,897. Of this amount, $5,275,317 was charged to Account 593 Maintenance of Overhead Lines – Distribution, with the remainder of the expense charged to Account 571 Maintenance of Overhead Lines – Transmission.[3]

Q. Has AE proposed what it describes as a "known and measurable" adjustment to the Fiscal Year 2021 heavy equipment lease expense?

A. Yes. AE has adjusted the heavy equipment lease expense to reflect the forecasted three-year average expense for Fiscal Years 2023 – 2025. The effect of this adjustment is to increase test year distribution O&M expense by $7,407,652 (AE Work Paper D-1.2.12).

Q. Has AE shown that budgeted three-year average expense for Fiscal Years 2023 – 2025 is known and measurable?

A. No. AE has described the purpose of the heavy equipment leases and has provided calculations supporting the estimates of the future costs. However, in response to ICA 4-4, AE acknowledged that the projected lease costs for FY 2023-2025 are not contractual obligations. Referring to the attachment in the response to ICA 2-8, it can be seen that the major increases in the forecasted heavy equipment lease expense are not

[3] Expenses charged to transmission do not affect the base rate revenue requirement in this case, as the transmission revenues on AE Schedule A (Summary of Total Cost of Service by Function) are synchronized with the transmission revenue requirement.

expected to start until May 2023. In my opinion, these increases are too remote from the Fiscal Year 2021 test year and too uncertain to be considered "known and measurable."

Q. What do you recommend?

A. The attachment in the response to ICA 2-8 shows the budgeted heavy equipment lease expense for Fiscal Year 2022 as well as the actual expense for Fiscal Year 2021 and forecasted expenses for Fiscal Years 2023 – 2025. There is a slight increase in the lease expense from Fiscal Year 2021 to Fiscal Year 2022 because a new lease contract that commenced in Fiscal Year 2021 was in effect for all of Fiscal Year 2022. I believe that it is reasonable to reflect the Fiscal Year 2022 heavy equipment lease expense increase in the AE revenue requirement. But unless AE can better substantiate the increases being projected for Fiscal Years 2023 – 2025, there should be no adjustment to the heavy equipment lease expense beyond the increase in Fiscal Year 2022.

Q. What is the effect of limiting the heavy equipment lease expense adjustment to the increase in expense from Fiscal Year 2021 to Fiscal Year 2022?

A. In Fiscal Year 2022, the budgeted heavy equipment lease expense charged to distribution O&M is $5,338,896.96 (response to ICA 2-8, Attachment Page 2). This is $7,344,072 less than the projected three-year average of $12,682,969 for Fiscal Years 2023 – 2025. Accordingly, the AE revenue requirement should be reduced by $7,344,072 (Schedule DJE-1).

E. CALL CENTER STAFFING CONTRACT

Q. Has AE adjusted the actual test year expense of staffing its customer call center to reflect a new contract with its staffing contractor?

A. Yes. As explained by AE in its response to ICA 2-9, in February 2022, "the Austin City Council approved a new multi-term contract with Howroy-Wright Employment Agency Inc. d/b/a AppleOne Employment for temporary staffing services for the Austin Energy Customer Care team, for up to five years for a total contract not to exceed $68,800,000." The annual cost of this contract as calculated by AE is $13,754,724, which is $5,382,525 greater than the actual call center staffing expense of $8,372,198 in Fiscal Year 2021. The expense adjustment of $5,382,525 represents an increase of approximately 64% over the actual Fiscal Year 2021 expense. The response to ICA 2-9 also describes this as a "known and measurable" adjustment for the call center staffing contract.

Q. Based on your review, is the increase to the call center staffing expense known and measurable?

A. No. As noted above, the $68,800,000 for five years ($13,760,000 per year) is a "not to exceed" amount. Further, the details the calculation of the adjustment for the staffing contract provided as an attachment to the response to ICA 2-9 clearly states that "The quantities listed herein are *estimates* for year one of the contract. The City reserves the right to purchase more or less of these quantities as may be required during the Contract term" (emphasis added). Although the hourly billing rates for the indicated labor classifications may be known, the quantities are not. The increase to the actual Fiscal

Year 2021 expense is not “known and measurable” based on the information provided by AE.

Q. Are you proposing to modify the AE adjustment to the call center expense?

A. Yes. Based on my count, the attachment to the response to ICA 2-9 includes 234 employees in the estimate of the annual cost of the new contract. Based on the response to ICA 4-5, the actual number of employees as of end of April 2022 was 185. Thus, the actual number of employees was 49 fewer than the number of employees assumed by AE in calculating the estimated annual cost of the new staffing contract. This equates to a difference of 20.9% in the number of employees. Therefore, the cost of the new staffing contract included in the AE revenue requirement should be reduced by 20.9%

Q. What is the effect of reducing the estimated cost of the new staffing contract by 20.9%?

A. The effect of this modification is to reduce the AE revenue requirement by $2,880,623 (Schedule DJE-1).

F. OTHER REVENUES

Q. Has AE adjusted the actual 2020 test year revenues for facilities rentals, which are included in “Other Revenues”?

A. Yes. As can be seen on AE Work Paper E-5.1.2, AE has reduced the actual 2020 test year “Other Revenues” for facilities rentals by $1,836,826. AE describes this adjustment as an adjustment to revenue to reflect a change in rental revenue from a particular customer. As "Other Revenues" are an offset to the base rate revenue requirement, this adjustment results in a direct and equal increase to the AE revenue requirement.

Q. Has AE further explained this adjustment?

A. Yes. In response to ICA 2-11 (attached), AE stated that "The adjustment to facilities rental is related to a disputed bill for pole attachments. Austin Energy does not expect to collect payment from this invoice."

Q. Did AE explain why it does not expect to collect payment?

A. In response to ICA 4-6 (attached), AE said that "This is due to the uncertainty of collecting on AT&T pole attachment bills due to an ongoing dispute and negotiations on an expired contract."

Q. Has AE established that it will not collect payment on disputed bills for facilities rentals?

A. No. AE has established that the bills are in dispute. However, this does not establish with a reasonable degree of certainty that there will be no recovery of the balances due.

Q. What do you recommend?

A. AE has not shown that the disputed bills for facilities rentals will not be unrecoverable or that the ongoing revenues from this source will be zero prospectively. Accordingly, I recommend that the adjustment to reduce Other Revenues by $1,836,826 be eliminated. The elimination of this adjustment reduces the AE base rate revenue requirement by $1,836,826.

G. GENERAL FUND TRANSFER

Q. How did AE calculate the General Fund Transfer that is included in its revenue requirement?

A. The General Fund Transfer (or "GFT") was calculated as 12% of the revenues less power supply costs. The calculation of the General Fund Transfer is shown on AE Work Paper WP C-3.2.1. As can be seen on this Work Paper, the base rate revenues included in the base for the application of the 12% GFT factor reflect the base rate revenue requirement as determined by AE.

Q. Are you proposing to adjust the General Fund Transfer included in the AE revenue requirement?

A. Yes. To the extent that other elements of the base rate revenue requirement are modified, the revenue base for the calculation of the General Fund Transfer must be modified accordingly. As I am proposing reductions to the base rate revenue requirement, these reductions will result in a reduction to the applicable revenue base and to the General Fund Transfer.

Q. Have you have calculated your adjustment to the General Fund Transfer by simply applying the 12% factor to the sum of your other revenue requirement adjustments?

A. No. The General Fund Transfer is itself included in the base rate revenue requirement on which it is calculated. In other words, the total revenue requirement includes GFT on GFT. Therefore, to capture the effect of other revenue requirement adjustments and recognize the effect of the GFT on GFT, the 12% factor must be "grossed up." This can be accomplished by dividing the 12% by its complement, or 1-.12. Accordingly the grossed-up GFT factor is 12%/(1-.12), or 13.64%.

Q. What adjustment to the General Fund Transfer have you calculated?

A. Applying the grossed-up GFT factor of 13.64% to my other revenue requirement adjustments, I have calculated an adjustment of $5,002,979 to the General Fund Transfer included in the AE revenue requirement (Schedule DJE-1).

Q. Does this conclude your Direct Testimony?

A. Yes.

AUSTIN ENERGY
BASE RATE REVIEW
SUMMARY OF PROPOSED REVENUE REQUIREMENT ADJUSTMENTS

Revenue Deficiency per Austin Energy			$48,219,749
Adjustments:		AE Reference	
Non-Nuclear Decommissioning	(A)	WP C-3.6	(6,000,000)
South Texas Project (STP) O&M	(B)	WP D-1.2.1	(9,324,751)
Rate Case Expense	(C)	WP D-1.2.7	(238,800)
Heavy Equipment Leases	(D)	WP D-1.2.12	(7,344,072)
Call Center Staffing Contract	(E)	WP D-1.2.14	(2,880,263)
Disputed Revenue Rental	(F)	WP E-5.1.2	(1,836,826)
Uncollectible Accounts Expense	(G)	WP D-1.2.6	(1,419,191)
Winter Storm Uri	(G)	WP D-1.2	(5,440,000)
Late Fee Revenues	(G)	WP E-5.1	(2,204,612)
General Fund Transfer	(H)	WP C-3.2.1	(5,002,979)
Total Adjustments			(41,691,494)
Revenue Deficiency per ICA			$ 6,528,255

Sources:

(A)	Schedule DJE-2		
(B)	Schedule DJE-3		
(C)	AE Work Paper WP D-1.2.7	1791000/5-597000	
(D)	Lease Expense - FY 2022 (Dist)	ICA 2-8	5,338,897
	Lease Expense - FY 2023-2025 (Dist)	ICA 2-8	12,682,969
	Difference		(7,344,072)
(E)	Actual Employees as of April 2022	ICA 4-5	185
	Employees Included by AE in Annual Cost	ICA 2-9	234
	Difference		(49)
	Percentage Difference		-20.9%
	AE Estimated Annual Cost	ICA 2-9	13,754,724
	Adjustment to Annual Expense		(2,880,263)
(F)	AE Work Paper WP E-5.1.2		
(G)	Testimony of Mr. Johnson		
(H)	Sum of Other Revenue Requirement Adjustments - Above		(36,688,515)
	Grossed Up GFT Rate	0.12/(1-0.12)	13.64%
	Adjustment to GFT		(5,002,979)

AUSTIN ENERGY
BASE RATE REVIEW
NON-NUCLEAR DECOMMISSIONING

		Low Estimate	High Estimate	Mid-Point
Decker Creek Units 1 and 2	(A)	$18,551,374	$27,721,374	$23,136,374
Fayette Power Project (AE Share)	(A)	15,780,000	29,590,000	22,685,000
Sand Hill Energy Center	(A)	11,856,000	22,082,000	16,969,000
Total Cost		$46,187,374	$79,393,374	$62,790,374

		Steam	Combustion Turbine
Plant in Service	(B)	720,227,010	437,427,617
Accumulated Depreciation	(C)	569,856,323	241,223,414
Net Plant		150,370,687	196,204,203
Depreciation	(D)	19,911,157	13,571,401
Remaining Life (Years)		7.6	14.5
Weighted Average Remaining Life		(E)	9.4

Total Non-Nuclear Decommissioning Cost (Mid-point)		$62,790,374
Recovered Through 12/31/2022	(F)	48,000,000
Remaining to be Recovered		$14,790,374
Remaining Life		9.4
Annual Non-Nuclear Decommissioning Expense		$ 1,570,408
Recommended Annual Non-Nuclear Decommissioning Contribution		$ 2,000,000
Annual Contribution, per AE	(G)	8,000,000
Adjustment to AE Non-Nuclear Decommissioning Contribution		$ (6,000,000)

Sources:
- (A) Attachment ICA RFI 2-5
- (B) AE Schedule B-1
- (C) AE Schedule B-5
- (D) AE Schedule E-1
- (E) Weighted by estimated decommissioning cost
- (F) $8 million per year for 6 years
- (G) AE Work Paper C-3.6

AUSTIN ENERGY
BASE RATE REVIEW
SOUTH TEXAS PROJECT (STP) O&M

	FY2019	FY2020	FY2021	Average
Total STP O&M	49,555,288	59,882,109	60,817,926	56,751,774
Adjustment for Non-Cash Expenses	2,433,551	(3,812,534)	(12,608,143)	(4,662,375)
STP Cash O&M	51,988,839	56,069,575	48,209,783	52,089,399
Actual FY 2021 Expenses as Booked				60,817,926
Adjustment to Reflect 3 Year Average Non-Cash Expenses				(8,728,527)
Adjustment Reflected by AE				596,224
Adjustment to AE Test Year Expenses				$ (9,324,751)

Source: AE Work Paper WP D-1.2.1

ICA 2-5: Referring to Appendix C, Page C-76, please provide documentation supporting the Annual Contribution to the Non-Nuclear Decommissioning Reserve. The response should provide support for the amount of the annual expense and should explain whether the amount represents an actual cash disbursement.

ANSWER: Financial Policy 21 (see Austin Energy’s 2022 Base Rate Filing Package, Appendix page B-3) requires that funding for decommissioning non-nuclear generation plants be set aside over a minimum of four years prior to the expected plant closure. The estimated cost of decommissioning Austin Energy’s non-nuclear plants is captured in a redacted 2015 report, attached as Attachment ICA RFI 2-5. $8 million cash per year is reclassified as a restricted reserve for this purpose.

Fund Summary Category	Fund	Agency	Org #	Organization Name	2022 Approved
Non-Nuclear Decommissioning	5010	1100	2209	Non-Nuclear Decommissioning	$8,000,000

Attachment ICA RFI 2-5: Non-Nuclear Decommissioning Cost Study (Public)

Prepared by: MG & GR

Sponsored by: Grant Rabon

FINAL REPORT | July 27, 2015

NON-NUCLEAR DECOMMISSIONING COST STUDY

Austin Energy
Austin, Texas

PREPARED BY:

NewGen Strategies & Solutions

ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY

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Non-Nuclear Decommissioning Cost Study

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Non-Nuclear Decommissioning Cost

Introduction and Overview

At the request of Austin Energy ("AE"), NewGen Strategies and Solutions, LLC ("NewGen") and its subconsultants, AECOM Technical Services, Inc. ("AECOM") and Encotech Engineering Consultants, Inc. ("Encotech"), prepared decommissioning and demolition cost estimates for Decker Creek Power Station ("Decker") Units 1 and 2, AE's ownership share in Fayette Power Project Units 1 and 2 and associated common facilities, and the Sand Hill Energy Center.

This report summarizes the results of the decommissioning cost study. More detailed information is provided in the following appendices to this report.

- Appendix A: Decker Creek Power Station Plant Decommissioning Cost Estimate (Detailed Site Specific Estimate)
- Appendix B: Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center
- Appendix C: Survey of Public Utility Commission Proceedings Regarding Non-Nuclear Decommissioning Costs

Decker Creek Units 1 and 2

As requested by AE, the scope of the Decker decommissioning and demolition cost estimate includes Decker Units 1 and 2 and other buildings and equipment delineated in the AECOM report provided in Appendix A. Decker Units 1 and 2 are two gas-fired steam turbine generating units constructed between 1967 and 1971 with a capacity of 321 megawatts ("MW") and 405 MW, respectively. The scope of work for the Decker decommissioning cost study does not include the four gas turbines at Decker.

The Decker decommissioning cost estimate is a detailed engineering, site specific cost estimate. The cost estimate was prepared by an AECOM team consisting of cost estimators, hazardous materials abatement experts, and personnel previously involved in the decommissioning of similar plants. Encotech was utilized to provide the concrete quantities for disposal and the steel quantities for scrap value credit. The project team made two site inspections of the Decker Creek Power Station for the purpose of identifying the buildings and equipment to be included in the decommissioning cost estimate.

During the development of the cost estimate, AECOM coordinated with AE to define the scope of work and associated assumptions in preparing the cost estimate. The agreed upon assumptions are discussed in more detail in the AECOM report provided in Appendix A. Some of the key assumptions are:

- Hazardous materials surveys and quantity calculations have not been completed for Decker. Because the Holly Power Plant and Decker Units 1 and 2 were constructed in the same time period and are similar in size, actual quantities of hazardous materials for the Holly Power Plant Decommissioning Project[1] were used for the Decker cost estimate.

- The Decker decommissioning cost estimate assumes removal of all concrete, piping, ducts, etc. to a depth of five feet below ground surface. Any items deeper will be left in place with the exception of the subsurface fuel oil lines and the 4160 duct banks. The cost to fully remove the subsurface fuel oil lines and the 4160 duct banks, regardless of depth, was included in the estimate based on input provided by AE.
- Allowances for the scrap value of steel, copper, and aluminum are included in the cost estimate. It is assumed that all equipment to be decommissioned have no resale value and therefore it was assumed the equipment will be recycled for scrap value.
- The decommissioning cost estimate includes costs to restore the decommissioned areas. Site restoration activities include backfilling all excavated underground duct banks, pits, and foundations with clean off-site fill after removal. The estimate assumes the final restored surface will consist of crushed stone in the turbine and boiler building areas and topsoil and seeding at the location of the fuel oil storage tanks. Restoration activities include leveling the earthen berms surrounding the two fuel oil tanks.

AECOM prepared a risk register in accordance with the AACE International Recommended Practice No. 40R-08 "Contingency Estimating" to quantitatively evaluate the potential impact and probability of occurrence for areas of risk. The overall contingency allowance for the decommissioning cost estimate was determined based on the sum of the allowances for each item in the risk register. The overall contingency allowance included in the estimated decommissioning cost is equal to 16.1 percent.

To estimate the total costs associated with the decommissioning of Decker Units 1 and 2, AECOM solicited input from AE on owner's costs from the Holly Power Plant, a similar power plant decommissioning project recently completed. Owner's costs include costs incurred by AE staff before and during the decommissioning process such as de-oiling, de-energizing, and isolating equipment before dismantlement activities begin; engineering and permitting costs; and construction management and oversight costs. In addition, AECOM estimated a range of costs for soil and groundwater remediation costs based on the Holly Power Plant decommissioning. The owner's costs provided by AE were scaled and applied as appropriate to Decker Units 1 and 2, as well as Fayette Units 1 and 2 and the Sand Hill Energy Center discussed later in this report.

Table 1 shows a summary of the decommissioning cost estimate for Decker Creek Units 1 and 2. All costs shown are in 2015 dollars.

[1] Holly Power Plant Decommissioning Project, *Building Decommissioning Report*, prepared by Weston Solutions, Inc., April 2014.

Table 1
Decommissioning Cost Estimate
Decker Creek Units 1 and 2

Task	Description	Estimated Costs
01	Contractor Field OH and General Conditions	$ [redacted]
02	Mobilization	[redacted]
03	Environmental Controls	[redacted]
04	Hazardous Materials Abatement Allowances	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]
06	Demolition	[redacted]
07	Site Restoration	[redacted]
08	Recycling & Salvaging	[redacted]
09	Demobilization	[redacted]
	Contingency	[redacted]
	Total Detailed Costs for Demolition	**$ 11,131,374**

Other Estimated Project Costs

Task	Low Range Estimate	High Range Estimate
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (20%-30%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Costs	**$ 18,551,374**	**$ 27,721,374**

Source: Appendix A, AECOM report, Decker Creek Power Station, and Plant Decommissioning Cost Estimate. See AECOM report for description of assumptions and analysis used to develop cost estimates.

Fayette Power Project and Sand Hill Energy Center

For the Fayette Power Project and Sand Hill Energy Center, AE requested that the decommissioning cost estimate be developed using a benchmark approach based on scaled costs from actual decommissioning costs for similar power plants. AECOM's letter report describing the Benchmark Cost Estimate for Fayette Power Project and Sand Hill Energy Center is provided in Appendix B.

The Fayette Power Project is a 1,625 MW coal-fired power plant that was constructed between 1979 and 1980. AE shares 50 percent ownership of Units 1 and 2 at the Fayette Power Project with the Lower Colorado River Authority. AE has no ownership interest in Unit 3 at the Fayette Power Project. For the Fayette Power Project, only Fayette Units 1 and 2 (590 MW each) and the common plant for Fayette Units 1, 2, and 3 identified in the equipment list in Appendix B were included in the Fayette Power Project benchmark cost estimate. The percentage of ownership applied to the benchmark cost estimate is 50 percent for Units 1 and 2 and 36 percent for the common items for Units 1, 2, and 3 as described in Appendix B.

The Sand Hill Energy Center consists of six 45 MW gas turbines and a 300 MW natural gas, combined cycle power plant that were constructed between 2001 and 2010. AE owns 100 percent of the Sand Hill Energy Center; therefore, all the equipment listed in Appendix B was included in the benchmark estimate.

For the benchmark estimates, AECOM identified major decommissioning tasks for the Fayette Power Project and Sand Hill Energy Center. The cost estimates for each major task were prepared by scaling on a dollar per kilowatt ("$/kW") basis from decommissioning costs from similar power plants. In addition, AECOM incorporated available plant specific information, including equipment and building lists, site layouts, and the potential presence of hazardous materials based on the age of the plant.

To estimate the total costs associated with the decommissioning of the Fayette Power Project and Sand Hill Energy Center, AECOM used data provided by AE on owner's costs from the Holly Power Plant decommissioning to estimate owner's costs for Fayette Units 1 and 2 and the Sand Hill Energy Center. The actual owner's costs provided by AE were scaled and used to estimate owner's costs for the benchmark estimates.

Tables 2 and 3 present the benchmark decommissioning cost estimates for AE's ownership share in the Fayette Power Project and the Sand Hill Energy Center, respectively. See AECOM's letter report in Appendix B for the equipment lists and assumptions used in the development of the benchmark cost estimates.

Table 2
Benchmark Decommissioning Cost Estimate
Fayette Power Project

Task	Description	Total Project Cost: Low Range Estimate	Total Project Cost: High Range Estimate
01	Contractor Field OH and General Conditions	$ [redacted]	$ [redacted]
02	Mobilization	[redacted]	[redacted]
03	Environmental Controls	[redacted]	[redacted]
04	Hazardous Materials Abatement	[redacted]	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]	[redacted]
06	Demolition	[redacted]	[redacted]
07	Site Restoration	[redacted]	[redacted]
08	Recycling & Salvaging	[redacted]	[redacted]
09	Demobilization	[redacted]	[redacted]
	Contingency (30%)	[redacted]	[redacted]
	Demolition Subtotal Costs	**$ 20,150,000**	**$ 34,260,000**

Other Estimated Project Costs

	Low Range Estimate	High Range Estimate
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (15%-25%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Cost Estimate:	**$ 37,320,000**	**$ 68,560,000**
AE 50% Ownership (Units 1 and 2) and 36% (Common Areas)	**$ 15,780,000**	**$ 29,590,000**

Source: Appendix B, AECOM letter report, and Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center. See AECOM letter report for description of assumptions and analysis used to develop cost estimates.

Table 3
Benchmark Decommissioning Cost Estimate
Sand Hill Energy Center

		Total Project Cost	
Task	Description	Low Range Estimate	High Range Estimate
01	Contractor Field OH and General Conditions	$ [redacted]	$ [redacted]
02	Mobilization	[redacted]	[redacted]
03	Environmental Controls	[redacted]	[redacted]
04	Hazardous Materials Abatement	[redacted]	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]	[redacted]
06	Demolition	[redacted]	[redacted]
07	Site Restoration	[redacted]	[redacted]
08	Recycling & Salvaging	([redacted]	([redacted]
09	Demobilization	[redacted]	[redacted]
	Contingency (30%)	[redacted]	[redacted]
	Demolition Subtotal Costs	**$ 5,716,000**	**$ 10,382,000**

Other Estimated Project Costs		
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (20%-30%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Costs	**$ 11,856,000**	**$ 22,082,000**

Source: Appendix B, AECOM letter report, and Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center. See AECOM letter report for description of assumptions and analysis used to develop cost estimates.

Public Utility Commission Data Regarding Non-Nuclear Decommissioning Costs

NewGen researched utility rate case filings and public utility commission ("PUC") orders regarding non-nuclear decommissioning costs used by other utilities. Our analysis of PUC decommissioning cost data included a review of utility filings and commission orders from Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Louisiana, Nevada, New Mexico, and Texas. The detailed data is provided in Appendix C.[2] Table 4 shows the median and mean decommissioning cost requested by utilities and the median and mean decommissioning cost

[2] Appendix C is an update of data presented in SOAH Docket No. 473-13-0935 and Public Utility Commission of Texas Docket No. 40627 on behalf of AE in the Rebuttal Testimony of Nancy Heller Hughes.

approved by the PUCs on a $/kW basis. Because some rate cases are still in progress, the number of data points represented in the "Approved Average" is less than the "Requested Average."

Table 4
Summary of PUC Rate Cases
Average Non-Nuclear Decommissioning Costs

Coal-Fired Steam $/kW		
	Approved	Requested
Median	$36.15	$47.99
Mean	$39.45	$74.31
Std. Dev. Above Mean	$69.19	$132.68
Std. Dev. Below Mean	$9.70	$15.95
Sample Size	19	27

Gas-Fired Steam $/kW		
	Approved	Requested
Median	$20.40	$23.74
Mean	$17.40	$33.09
Std. Dev. Above Mean	$28.57	$63.76
Std. Dev. Below Mean	$6.23	$2.43
Sample Size	8	14

Gas Turbine $/kW		
	Approved	Requested
Median	$11.02	$29.11
Mean	$19.61	$51.18
Std. Dev. Above Mean	$39.80	$112.22
Std. Dev. Below Mean	($0.59)	($9.87)
Sample Size	5	8

Combined Cycle $/kW		
	Approved	Requested
Median	$17.24	$19.98
Mean	$20.56	$21.26
Std. Dev. Above Mean	$33.14	$33.73
Std. Dev. Below Mean	$7.99	$8.80
Sample Size	15	16

Source: Appendix C, utility rate filings and PUC decisions.

The PUC data shown in Table 4 includes decommissioning cost estimates approved by regulatory commissions or requested by utilities in 2009 through 2014. In some cases, NewGen was able to obtain a copy of the site specific dismantlement study filed by a utility; however, more often, only the results of the studies or approved decommissioning costs are available.

As shown in Table 4, there is a wide range of decommissioning cost estimates on a $/kW basis for each type of power plant. For example, for coal-fired steam plants, the average (mean) commission-approved decommissioning cost is equal to $39.45/kW, with costs ranging one standard deviation below and above the mean from $9.70/kW to $69.19/kW. Costs will vary depending on the scope of the decommissioning activities, the amount of salvage value included in the cost estimate, the extent of soil and groundwater remediation activities, and owner's costs. A breakdown of these costs is usually not available from the PUC data unless the dismantlement cost study is available.

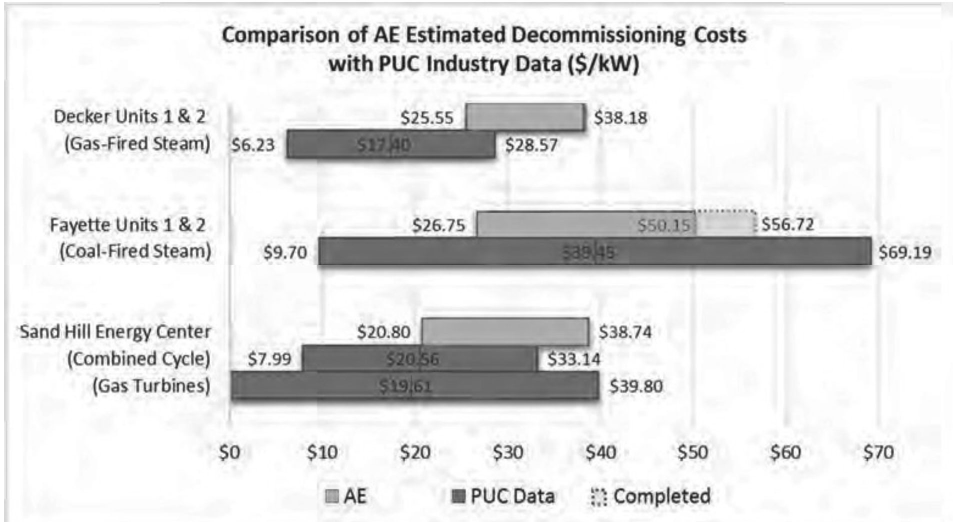
Table 5 shows the estimated decommissioning costs for Decker Units 1 and 2, Fayette Units 1 and 2, and Sand Hill Energy Center expressed on a dollars per kW basis based on the data conveyed in Tables 1, 2, and 3. Note the range listed for Fayette Units 1 and 2 does not include work already completed (including the closure of an ash pond).

Table 5
Estimated Non-Nuclear Decommissioning Costs
($/kW)

Generating Unit	Type of Plant	Capacity (MW)	Retirement Year	Decommissioning Cost ($/kW)	
				Low	High
Decker Units 1 and 2	Gas-fired steam	726	2018	$25.55	$38.18
Fayette Units 1 and 2*	Coal-fired steam	590	2025	$26.75	$50.15
Sand Hill Energy Center	Combined Cycle and Gas Turbines	570	2030	$20.80	$38.74

* The 590 MW capacity reflects AE's ownership share in the two units, rather than the total capacity of the units.

Figure 1 shows a comparison of the decommissioning cost estimates prepared by AECOM for Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center with the PUC industry data presented in Table 4 by type of plant.



Source: Tables 4 and 5

Figure 1
Comparison of AE Estimated Decommissioning Costs with PUC Industry Data ($/kW)

Figure 1 shows the range of estimated decommissioning costs for Decker Units 1 and 2 and the Sand Hill Energy Center are at or above the high end of the range of decommissioning costs approved by PUCs. This is primarily due to the level of owner's costs that are included in the decommissioning cost estimates for AE's generating units.

AECOM utilized data provided by AE regarding owner's costs from the Holly Power Plant decommissioning to estimate the owner's costs for Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center. The level of owner's costs will depend on how involved the utility is in the decommissioning project. Since AE tends to be very involved in its projects, we would expect the owner's costs to be at the higher end of the range of PUC industry data than the lower end. Relying on data from the Holly Power Plant decommissioning is a reasonable way to estimate AE owner's costs on future decommissioning projects.

Figure 1 also shows the range of estimated decommissioning costs for Fayette Units 1 and 2, including decommissioning work already completed, which is in the middle to higher end of the range of decommissioning costs approved by PUCs. The completed work identified in Figure 1 for Fayette Units 1 and 2 is equal to AE's 50 percent share of remediation costs for one ash pond that has been closed. If the cost of the ash pond closure ($6.57 per kW) is added back to the owner's costs, the cost to decommission Fayette Units 1 and 2 is in the range of approximately $33/kW to $57/kW.

Non-Nuclear Decommissioning Reserve

AE Financial Policy No. 21, which established the Non-Nuclear Decommission Reserve, states that funding for the decommissioning of a plant will be set aside over a minimum of four years prior to the expected plant closure. The funds in the Non-Nuclear Decommissioning Reserve are restricted to use for generation decommissioning costs, but not associated with a particular plant or unit. The Non-Nuclear Decommissioning Reserve was established in 2002 to accumulate funds for the Holly Power Plant decommissioning.

Recommendations

NewGen recommends AE take the following steps to begin accumulating funds in the Non-Nuclear Decommissioning Reserve to pay to decommission Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center in the future:

- Given the near-term goal of retiring Decker Units 1 and 2 by fiscal year 2018, and AE's financial policy requiring that funds be set aside over a minimum of four years prior to the expected plant closure, NewGen would recommend that AE begin accumulating additional funds in the Non-Nuclear Decommissioning Reserve as soon as practical.
- NewGen recommends targeting the high end of the estimated range of costs for decommissioning Decker Units 1 and 2. Although the Decker decommissioning cost estimate was developed based on a site specific engineering cost estimate, there are still areas of the cost that could represent significant liabilities that need further investigation (e.g., remediation needs). If the cost of decommissioning the Decker units proves to be less than the high end of the estimate, the savings can be applied to the decommissioning of the next plant. Thus, funds set aside in the reserve will be used for their intended purpose, even if they end up not being needed at Decker.
- NewGen also recommends that AE begin accumulating funds in the Non-Nuclear Decommissioning Reserve as soon as practical for the future decommissioning of Fayette Units 1 and 2 and the Sand Hill Energy Center. In doing so, there is better alignment between the customers benefiting from the power plants while they are in service and the customers paying for the eventual dismantlement of the facilities in the future. In addition, the earlier AE starts the process of setting aside funds for each generation unit, the lower the potential rate impact and the more equitable the recovery of these costs.

ICA 2-6: Referring to Appendix C, Page C-96, please explain what the non-cash amounts represent and why the credit amount in FY 2021 was so large. The response should also explain why a separate adjustment is necessary for the non-cash amounts if the non cash-amounts are already included in Account 924.

ANSWER: This response assumes the reference to Account 924 should be Account 524 as reflected on Page C-96. The non-cash amounts represent the expense accruals for the STP asset retirement obligation required by GASB (Governmental Accounting Standards Board). The non-cash amounts represent the portion of the decommissioning obligation that was not cash funded each year. The amount has been increasing recently for several reasons, including increases in the estimated cost of decommissioning, static funding to the trust, and low interest rates causing the trust fund to earn less in interest. The adjustment in the Rate Filing Package for non-cash decommissioning expense in FERC 524 was intended to remove the non-cash amount from the Test Year. The adjustment will be corrected.

Prepared by: MG

Sponsored by: Grant Rabon

ICA 2-8: Referring to Appendix C, Page C-113, please provide the budgeted heavy equipment lease expense for Fiscal Year 2022 and documentation supporting the budgeted heavy equipment lease expenses for Fiscal Years 2023, 2024, and 2025.

ANSWER: Austin Energy leases heavy equipment used in operations from Altec.

Attachment ICA RFI 2-8 details the calculation of the known and measurable adjustment for the Altec lease contract.

Attachment ICA RFI 2-8: SD WP D_1_2_12 Altec Lease Increase K&M

Prepared by: GJ/RS

Sponsored by: Mark Dombroski

Adjustment For Heay Equipment Leases K&M

	2021	2022	2023	2024	2025	Monthly Amount	Prorated Initial FY	Prorated Final FY	Check
Phase 1 - Municipal Lease (Phase One) Delivery Date: 4/26/2018 Pick-up Date: 4/25/2023	$ 269,029.44	$ 269,029.44	$ 156,933.84			22,419.12	5	7	12
	$ 134,139.84	$ 134,139.84	$ 78,248.24			11,178.32	5	7	12
	$ 130,904.40	$ 130,904.40	$ 76,360.90			10,908.70	5	7	12
	$ 258,023.76	$ 258,023.76	$ 150,513.86			21,501.98	5	7	12
	$ 77,223.96	$ 77,223.96	$ 45,047.31			6,435.33	5	7	12
	$ 168,828.12	$ 168,828.12	$ 98,483.07			14,069.01	5	7	12
	$ 98,478.60	$ 98,478.60	$ 57,445.85			8,206.55	5	7	12
Phase 2 - Municipal Lease (Phase Two) Delivery Date: 6/27/2018 Pick-up Date: 6/26/2023	$ 67,257.36	$ 67,257.36	$ 50,443.02			5,604.78	3	9	12
	$ 65,452.20	$ 65,452.20	$ 49,089.15			5,454.35	3	9	12
	$ 473,043.60	$ 473,043.60	$ 354,782.70			39,420.30	3	9	12
	$ 56,276.04	$ 56,276.04	$ 42,207.03			4,689.67	3	9	12
	$ 138,122.76	$ 138,122.76	$ 103,592.07			11,510.23	3	9	12
	$ 51,747.96	$ 51,747.96	$ 38,810.97			4,312.33	3	9	12
	$ 108,877.32	$ 108,877.32	$ 81,657.99			9,073.11	3	9	12
Phase 3 - Municipal Lease (Phase Three) Delivery Date: 2/1/2019 Pick-up Date: 1/31/2024	$ 137,650.20	$ 137,650.20	$ 137,650.20	$ 45,883.40		11,470.85	8	4	12
	$ 469,144.32	$ 469,144.32	$ 469,144.32	$ 156,381.44		39,095.36	8	4	12
	$ 221,083.80	$ 221,083.80	$ 221,083.80	$ 73,694.60		18,423.65	8	4	12
	$ 100,975.20	$ 100,975.20	$ 100,975.20	$ 33,658.40		8,414.60	8	4	12
	$ 52,794.36	$ 52,794.36	$ 52,794.36	$ 17,598.12		4,399.53	8	4	12
Phase 4 - Municipal Lease (Phase Four) Delivery Date: 4/1/2019 Pick-up Date: 3/29/2024	$ 137,650.20	$ 137,650.20	$ 137,650.20	$ 68,825.10		11,470.85	6	6	12
	$ 402,123.72	$ 402,123.72	$ 402,123.72	$ 201,061.86		33,510.31	6	6	12
	$ 88,433.52	$ 88,433.52	$ 88,433.52	$ 44,216.76		7,369.46	6	6	12
	$ 57,544.44	$ 57,544.44	$ 57,544.44	$ 28,772.22		4,795.37	6	6	12
	$ 66,135.60	$ 66,135.60	$ 66,135.60	$ 33,067.80		5,511.30	6	6	12
	$ 92,931.60	$ 92,931.60	$ 92,931.60	$ 46,465.80		7,744.30	6	6	12
	$ 355,470.36	$ 355,470.36	$ 355,470.36	$ 177,735.18		29,622.53	6	6	12
Phase 5 - Municipal Lease (Phase Five) Delivery Date: 7/6/2020 Pick-up Date: 7/7/2025	$ 443,966.40	$ 443,966.40	$ 443,966.40	$ 443,966.40	$ 332,974.80	36,997.20	3	9	12
	$ 58,434.96	$ 58,434.96	$ 58,434.96	$ 58,434.96	$ 43,826.22	4,869.58	3	9	12
	$ 59,231.04	$ 59,231.04	$ 59,231.04	$ 59,231.04	$ 44,423.28	4,935.92	3	9	12
	$ 114,248.64	$ 114,248.64	$ 114,248.64	$ 114,248.64	$ 85,686.48	9,520.72	3	9	12
	$ 128,205.72	$ 128,205.72	$ 128,205.72	$ 128,205.72	$ 96,154.29	10,683.81	3	9	12
	$ 56,193.12	$ 56,193.12	$ 56,193.12	$ 56,193.12	$ 42,144.84	4,682.76	3	9	12
	$ 72,113.76	$ 72,113.76	$ 72,113.76	$ 72,113.76	$ 54,085.32	6,009.48	3	9	12
Phase 6 - Municipal Lease (Phase Six) Delivery Date: 4/5/2021 Pick-up Date: 4/3/2026	$ 127,160.64	$ 254,321.28	$ 254,321.28	$ 254,321.28	$ 254,321.28	21,193.44	6	6	12
Phase 7 - Municipal Lease (Phase SEVEN) Delivery Date: 5/15/2023 Pick-up Date: 5/14/2028			$ 534,198.60	$ 1,424,529.60	$ 1,424,529.60	118,710.80	4.5	7.5	12
			$ 44,174.97	$ 117,799.92	$ 117,799.92	9,816.66	4.5	7.5	12
			$ 923,164.97	$ 2,461,773.24	$ 2,461,773.24	205,147.77	4.5	7.5	12
			$ 312,570.90	$ 833,522.40	$ 833,522.40	69,460.20	4.5	7.5	12
			$ 42,712.20	$ 113,899.20	$ 113,899.20	9,491.60	4.5	7.5	12
			$ 50,463.77	$ 134,570.04	$ 134,570.04	11,214.17	4.5	7.5	12
			$ 113,625.05	$ 303,000.12	$ 303,000.12	25,250.01	4.5	7.5	12
			$ 73,276.88	$ 195,405.00	$ 195,405.00	16,283.75	4.5	7.5	12
			$ 32,696.96	$ 87,191.88	$ 87,191.88	7,265.99	4.5	7.5	12
Phase 8 - Municipal Lease (Phase EIGHT) Delivery Date: 6/12/2023 Pick-up Date: 6/11/2028			$ 39,356.63	$ 134,937.00	$ 134,937.00	11,244.75	3.5	8.5	12
			$ 77,698.60	$ 266,395.20	$ 266,395.20	22,199.60	3.5	8.5	12
			$ 116,731.16	$ 400,221.12	$ 400,221.12	33,351.76	3.5	8.5	12

			$ 305,817.07	$ 1,048,515.65	$ 1,048,515.65	87,376.30	3.5	8.5	12
			$ 254,936.56	$ 874,068.20	$ 874,068.20	72,839.02	3.5	8.5	12
			$ 31,346.00	$ 107,472.00	$ 107,472.00	8,956.00	3.5	8.5	12
			$ 45,285.35	$ 155,264.04	$ 155,264.04	12,938.67	3.5	8.5	12
			$ 24,665.38	$ 84,567.00	$ 84,567.00	7,047.25	3.5	8.5	12
			$ 113,984.99	$ 390,805.68	$ 390,805.68	32,567.14	3.5	8.5	12
			$ 27,845.97	$ 95,471.88	$ 95,471.88	7,955.99	3.5	8.5	12
			$ 36,090.15	$ 123,737.66	$ 123,737.66	10,311.47	3.5	8.5	12
Phase 9 - Municipal Lease (Phase NINE) Delivery Date: 2/12/2024 Pick-up Date: 2/13/2029				$ 266,060.43	$ 425,696.68	35,474.72	7.5	4.5	12
				$ 458,183.25	$ 733,093.20	61,091.10	7.5	4.5	12
				$ 89,595.30	$ 143,352.48	11,946.04	7.5	4.5	12
				$ 612,143.98	$ 979,430.37	81,619.20	7.5	4.5	12
				$ 56,014.65	$ 89,623.44	7,468.62	7.5	4.5	12
Phase 10 - Municipal Lease (Phase TEN) Delivery Date: 3/11/2024 Pick-up Date: 3/10/2029				$ 73,887.61	$ 136,407.90	11,367.33	6.5	5.5	12
				$ 366,153.90	$ 675,976.43	56,331.37	6.5	5.5	12
				$ 415,695.28	$ 767,437.44	63,953.12	6.5	5.5	12
				$ 157,364.48	$ 290,519.04	24,209.92	6.5	5.5	12
				$ 389,719.98	$ 719,483.04	59,956.92	6.5	5.5	12
				$ 301,337.92	$ 556,316.16	46,359.68	6.5	5.5	12
TOTALS PER YEAR (not prorated)	$ 5,338,896.96	$ 5,466,057.60	$ 7,952,910.35	$ 14,653,379.21	$ 15,824,099.52				
Annual Change		**$ 127,160.64**	**$ 2,486,852.75**	**$ 6,700,468.86**	**$ 1,170,720.31**				
		CUM Delta	**$ 2,614,013.39**	**$ 9,314,482.25**	**$ 10,485,202.56**				
		THREE-year average	**$ 7,471,232.73**						

FERC 593 Maintenance of Overhead Lines - Dist	$ 5,275,316.64	$ 5,338,896.96	$ 7,825,749.71	$ 14,526,218.57	$ 15,696,938.88
FERC 571 Maintenance of Overhead Lines - Trans	$ 63,580.32	$ 127,160.64	$ 127,160.64	$ 127,160.64	$ 127,160.64
Total	$ 5,338,896.96	$ 5,466,057.60	$ 7,952,910.35	$ 14,653,379.21	$ 15,824,099.52

Known & Measurable Adjustment	**FY 2021 Budget**	**Three Year Average FY2023 - FY2025**	**Known & Measurable Adjustment**
FERC 593 Maintenance of Overhead Lines - Dist	$ 5,275,317	$ 12,682,969	**$ 7,407,652**
FERC 571 Maintenance of Overhead Lines - Trans	$ 63,580	$ 127,161	**$ 63,580**
Total	$ 5,338,897	$ 12,810,130	**$ 7,471,233**

ICA 2-9: Referring to Appendix C, Page C-115, please provide documentation supporting the Annual Expense under New Contract.

ANSWER: On February 17, 2022, the Austin City Council approved a new multi-term contract with Howroy-Wright Employment Agency Inc. d/b/a AppleOne Employment for temporary staffing services for the Austin Energy Customer Care team, for up to five years for a total contract not to exceed $68,800,000.

Attachment ICA RFI 2-9a details the calculation of the known and measurable adjustment for the AppleOne staffing contract, and Attachment ICA RFI 2-9b provides the contract rates by position, as well as the annual expenditures for those positions.

Attachment ICA RFI 2-9a: SD WP D_1_2_14 AppleOne Contract K&M.xlsx
Attachment ICA RFI 2-9b: AppleOne Rates.pdf

The AppleOne Contract is available at the following website:
https://financeonline.austintexas.gov/afo/contract_catalog/OCCViewMA.cfm?cd=MA&dd=1100&id=NA220000020

Prepared by: GJ/JG

Sponsored by: Jerry Galvan

Call Center Staffing Known & Measurable

Unit	Unit Name	Activity	Activity Name	Object Code	Object Name	Vendor	Vendor Naem	2019	2020	2021	Prorated Increase	Adjusted TY Expenses
8803	Cust. Complaints & Rsltn	9034	Customer Service	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC	$241,855.18	$51,058.76	$103,713.13	$66,677.65	$170,390.78
8804	Customer Care Staff Development	9034	Customer Service	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC	$379,080.05	$328,564.97	$250,642.44	$161,139.19	$411,781.63
8807	Bill Production	9031	Billing & Admin	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC	$760,627.85	$336,342.00	$637,099.66	$409,594.34	$1,046,694.00
8807	Bill Production	9031	Billing & Admin	5860	Services-other	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC		$0.00			$0.00
8807	Bill Production	9304	Communication Exp - AE	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC		$228,577.18	$0.00		$0.00
8813	Call Center	9034	Customer Service	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC	$4,625,304.11	$4,236,209.21	$1,777,044.12	$1,142,469.94	$2,919,514.06
8813	Call Center	9034	Customer Service	5860	Services-other	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC			$1,645,697.57	$1,058,026.63	$2,703,724.20
8831	311 Call Center Operations	4172	Exp Nonutlity Ops-311Call Cntr	5720	Services-temporary employme	APP8315034	HOWROYD-WRIGHT EMPLOYMENT AGENCY INC		$2,433,899.20	$3,958,001.54	$2,544,617.62	$6,502,619.16
							Total Expenses	$6,006,867.19	$7,614,651.32	$8,372,198.46	$5,382,525.38	$13,754,723.84
							FERC 903			$4,414,197	$2,837,908	$7,252,105
							FERC 930			0	0	0
							FERC 417			3,958,002	2,544,618	6,502,619
							Total FY21 Expenses			$8,372,198	$5,382,525	$13,754,724

Annual New Contract Spend (see NA2200000020 AppleOne Rates pdf)	$13,754,724
Adjustment to FY21 Actuals	**$5,382,525**

CITY OF AUSTIN
PURCHASING OFFICE
TEMPORARY STAFFING SERVICES FOR THE CONTACT CENTERS
SOLICITATION RFP 1100 EAL3015

PRICING SUBMITTAL FORM

The "Employees" column shows the number of employees in the corresponding labor classification that are estimated on an annual basis. The annual hours calculation is based on 2,080 hours per employee.

The quantities listed herein are estimates for year one of the contract. The City reserves the right to purchase more or less of these quantities as may be required during the Contract term.

Section 1.0 - Regular Time Rate Structure - Contract Personnel

Offorers are required to provide an Hourly Pay Rate and Billing Markup Percentage for the following labor classifications. The billing markup % shall include all general and administrative overhead costs.
"W/ COA Tech" means additional or dfferent cost of position working off-site or at home with technology (PC, Laptop, monitor, keyboard, mouse) supplied by the City (COA) and internet connection supplied by Contractor:

"W/ Cont. Tech" means additional or dfferent cost of position working off-site or at home with technology (PC, Laptop, monitor, keyboard, mouse) supplied by Contractor and internet connection supplied by Contractor:

ITEM	DESCRIPTION	Employees	Annual Hours	Hourly Pay Rate	Billing Markup %	Hourly Billing	Annual Price
1.01	Regular Rate Customer Service Representative	26	54,080	$17.00	40.00%	$23.80	$1,287,104.00
1.02	Regular Rate Customer Service Representative w/ COA Tech	143	297,440	$17.00	40.00%	$23.80	$7,079,072.00
1.03	Regular Rate Customer Service Representative w/ Cont. Tech	9	18,720	$17.00	41.00%	$23.97	$448,718.40
1.04	Regular Rate Program Coordinator	1	2,080	$22.00	40.00%	$30.80	$64,064.00
1.05	Regular Rate Program Coordinator w/ COA Tech	2	4,160	$22.00	40.00%	$30.80	$128,128.00
1.06	Regular Rate Customer Service Representative w/ Cont. Tech	1	2,080	$22.00	41.00%	$31.02	$64,521.60
1.07	Regular Rate IT Application Analyst	1	2,080	$34.00	40.00%	$47.60	$99,008.00
1.08	Regular Rate IT Application Analyst w/ COA Tech	1	2,080	$34.00	40.00%	$47.60	$99,008.00
1.09	Regular Rate Customer Service Representative w/ Cont. Tech	1	2,080	$34.00	41.00%	$47.94	$99,715.20
1.10	Regular IT Support Analyst	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.11	Regular IT Support Analyst w/ COA Tech	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.12	Regular IT Support Analyst w/ Cont. Tech	1	2,080	$26.00	41.00%	$36.66	$76,252.80
1.13	Regular Rate Client Relationship Analyst	2	4,160	$18.00	40.00%	$25.20	$104,832.00
1.14	Regular Rate Client Relationship Analyst w/ COA Tech	14	29,120	$18.00	40.00%	$25.20	$733,824.00
1.15	Regular Rate Client Relationship Analyst w/ Cont. Tech	1	2,080	$18.00	41.00%	$25.38	$52,790.40
1.16	Regular Rate Scheduling Analyst	1	2,080	$20.00	40.00%	$28.00	$58,240.00
1.17	Regular Rate Scheduling Analyst w/ COA Tech	1	2,080	$20.00	40.00%	$28.00	$58,240.00
1.18	Rehular Rate Scheduling Analyst w/ Cont. Tech	1	2,080	$20.00	41.00%	$28.20	$58,656.00
1.19	Regular Rate Quality Improvement Specialist	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.20	Regular Rate Quality Improvement Specialist w/ COA Tech	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.21	Regular Rate Quality Improvement Specialist w/ Cont. Tech	1	2,080	$26.00	41.00%	$36.66	$76,252.80
1.22	Regular Rate Training Instructor	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.23	Regular Rate Training Instructor w/ COA Tech	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.24	Regular Rate Training Instructor w/ Cont. Tech	1	2,080	$26.00	41.00%	$36.66	$76,252.80

1.25	Regular Rate IT Business Systems Analyst	1	2,080	$31.00	40.00%	$43.40	$90,272.00
1.26	Regular Rate IT Business Systems Analyst w/ COA Tech	1	2,080	$31.00	40.00%	$43.40	$90,272.00
1.27	Regular Rate IT Business Systems Analyst w/ Cont. Tech	1	2,080	$31.00	41.00%	$43.71	$90,916.80
1.28	Regular Rate Business Process Specialist	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.29	Regular Rate Business Process Specialist w/ COA Tech	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.30	Regular Rate Business Process Specialist w/ Cont. Tech	1	2,080	$26.00	41.00%	$36.66	$76,252.80
1.31	Regular Rate Customer Solutions Coordinator	1	2,080	$26.00	40.00%	$36.40	$75,712.00
1.32	Regular Rate Customer Solutions Coordinator w/ COA Tech	2	4,160	$26.00	40.00%	$36.40	$151,424.00
1.33	Regular Rate Customer Solutions Coordinator w/ Cont. Tech	1	2,080	$26.00	41.00%	$36.66	$76,252.80
1.34	Regular Rate Utility Account Specialist	1	2,080	$20.00	40.00%	$28.00	$58,240.00
1.35	Regular Rate Utility Account Specialist w/ COA Tech	8	16,640	$20.00	40.00%	$28.00	$465,920.00
1.36	Regular Rate Utility Account Specialist w/ Cont. Tech	1	2,080	$20.00	41.00%	$28.20	$58,656.00
TOTAL SECTION 1.0 - REGULAR TIME ESTIMATED ANNUAL PRICE:							**$12,504,294.40**

Section 2.0 - Overtime Rate Structure - *ALL* Contract Personnel

Offerors are required to provide the Overtime Markup %. This percentage will be applied to a ten percent estimated Overtime Hours for Section 1.0 of the Pricing Submittal to determine the estimated total Overtime/Call-Back Time Price.

ITEM	DESCRIPTION	Perecent Overtime	Overtime Markup %	Annual Price
2.01	Total Estimated Overtime Price	10.00%	32.00%	$1,250,429.44
	TOTAL SECTION 1.0 - REGULAR TIME ANNUAL PRICE:			**$12,504,294.40**
	TOTAL SECTION 2.0 - OVERTIME ANNUAL PRICE:			**$1,250,429.44**
	GRAND TOTAL ANNUAL PRICE:			**$13,754,723.84**

ICA 2-11: Referring to Appendix C, Page C-150, please provide documentation supporting the adjustments to Other Revenues.

ANSWER: Treated Coal Revenues are related to a contract at the Fayette Power Project associated with a federal tax credit that expired December 31, 2021 (Production Tax Credit for Refined Coal). This adjustment removes $3,731,532 from non-operating revenue.

The adjustment to facilities rental is related to a disputed bill for pole attachments. Austin Energy does not expect to collect payment from this invoice. Please refer to Attachment ICA RFI 2-11 for documentation supporting the adjustments to Other Revenues.

Attachment ICA RFI 2-11: Supporting Document—Redacted

Prepared by: JO

Sponsored by: Grant Rabon

Town Lake Center
721 Barton Springs Rd.
Austin, TX 78704

Invoice

Date	Invoice #
2/5/2021	[redacted]

Bill To
[redacted]

P.O. No.	Due Date	Service Period	REP
	3/22/2021	FY 2021	JH

Item	Description	Accounting Line	Amount
Annual Pole	2021 Annual Usage Fee	5010-1100-9180-4541...	1,835,736.00
Annual Pole	2021 Annual Usage Proration for New Attachments	5010-1100-9180-4541...	1,090.38

Please provide invoice number with payment. Remit payment to:

By Mail:
City of Austin-Austin Energy
P.O. Box 3513
Austin, TX 78764-3513

Wire/Funds Transfer Instructions:
Bank Name: [redacted]
ABA# [redacted]
Swift Code: [redacted]
Location: New York, NY
Credit to the Account of: City of Austin-Investment Pool Receiving Account
Account Number [redacted]
Email: AECorporateAccountingAR@austinenergy.com

ACH Instructions:
Bank Name: [redacted]
ABA# [redacted]
Swift Code: [redacted]
Location: New York, NY
Credit to the Account of: City of Austin-Investment Pool Receiving Account
Account Number: [redacted]
Email: AECorporateAccountingAR@austinenergy.com

Total	$1,836,826.38
Payments/Credits	$0.00
Balance Due	$1,836,826.38

ICA 4-4: Referring to the response to ICA 2-8, are the amounts for FY 2023-2025 contractual obligations? If so, please provide documentation supporting those obligations. The response should also explain what each of the "Phases" Seven through Ten represent and describe how the dollar amounts for those phases were determined.

ANSWER: No. The contractual obligations are strictly for leased vehicles through the Altec lease agreement for phases One through Six. Phases Seven through Eleven are not yet contracted. Austin Energy has two amendments to the Altec lease contract that are pending with Austin City Council for action in September 2022. Austin Energy believes both amendments will pass and will be in effect when new rates become effective.

One amendment provides for an extension due to supply chain delays to replace leased sunset vehicles from the original phases of the lease to ensure vehicles are kept in service until future phases are contracted and received. The second amendment is to contract Phases Seven through Eleven with future projections of lease costs and maintenance. Please see Attachment ICA 4-4, the finance worksheet which delineates base lease costs and unplanned maintenance costs using an escalation factor for fluctuating manufacturer costs.

See Attachment ICA 4-4.

Prepared by: RC

Sponsored by: Mark Dombroski

2021/10-1 Altec Amendment 3 Worksheet

Instructions: Please complete the required vehicle lists needed for each phase and the quantity of each vehicle per phase (column **A**) and the yellow highlighted areas, then send to Altec. Have Altec provide quotes for columns **B** and **C**. When you get the quotes back from Altec, complete column **D** using historical trend/expense information, then return the completed worksheet back to me *by COB Wednesday, October 6th*.
NOTE: You can add more rows to each phase as necessary.

Municipal Lease (Phase SEVEN) ***Delivery Date:*** *5/15/2023* ***Pick-up Date:*** *5/14/2028*	**(A)** **Quantity Required For Phase 7**	**(B)** **Price Per Unit(s) Per Month**	**(C)** **Extended Price Per Unit(s) for Phase 7 Time Period (60 months)**	**(D)** **Extended Allocation for Damages and/or Unscheduled Maintenance (60 months)**
Specification Type				
47' diggers single axle DC47	4	$29,219.00	$2,191,425.00	$110,088.00
50' diggers D4050	1	$9,316.66	$559,000.00	$27,522.00
48' buckets	11	$55,733.37	$3,344,000.00	$302,742.00
50' buckets	2	$20,150.01	$1,209,000.60	$82,566.00
77' buckets	1	$8,991.60	$539,500.00	$27,522.00
80' elevator A65'-E82'	1	$10,714.17	$648,850.00	$27,522.00
55' bucket	3	$14,833.34	$2,225,000.00	$55,044.00
65ton crane	1	$15,783.75	$947,025.00	$27,522.00
Backyard digger/bucket combo	1	$6,765.99	$405,959.15	$27,522.00
	TOTALS:	$149,593.64	$12,069,759.75	$688,050.00
Municipal Lease (Phase EIGHT) **Delivery Date: 6/12/2023** **Pick-up Date: 6/11/2028**	**(A)** **Quantity Required For Phase 8**	**(B)** **Price Per Unit(s) Per Month**	**(C)** **Extended Price Per Unit(s) for Phase 8 Time Period (60 months)**	**(D)** **Extended Allocation for Damages and/or Unscheduled Maintenance (60 months)**
Specification Type				
48' diggers tandem axel	1	$10,554.75	$633,285.00	$27,522.00
55' bucket	3	$23,362.50	$1,401,750.00	$82,566.00
48' buckets	13	$69,160.00	$4,149,600.00	$357,786.00
50' buckets	3	$21,157.50	$1,269,450.00	$82,566.00
60' buckets	1	$8,266.00	$495,960.00	$27,522.00
100' bucket	1	$12,248.67	$734,919.75	$27,522.00
Underground truck	1	$6,357.25	$381,435.25	$27,522.00
Effer automatic trans	1	$15,593.57	$935,613.70	$27,522.00
18ton crane	1	$7,265.99	$435,959.35	$27,522.00

67' bucket AN67	1	$10,621.47	$577,288.30	$27,522.00
TOTALS:		$184,587.70	$11,015,261.35	$715,572.00

Municipal Lease (Phase NINE) **Delivery Date:** 2/12/2024 **Pick-up Date:** 2/13/2029	**(A)** **Quantity Required For Phase 9**	**(B)** **Price Per Unit(s) Per Month**	**(C)** **Extended Price Per Unit(s) for Phase 9 Time Period (60 months)**	**(D)** **Extended Allocation for Damages (60 months)**
Specification Type				
48' buckets	5	$27,930.00	$1,675,800.00	$137,610.00
55' buckets	7	$57,238.02	$3,434,287.50	$192,654.00
67' bucket AN67	1	$11,152.54	$669,152.40	$27,522.00
48' diggers tandem axel	7	$77,577.43	$4,654,644.75	$192,654.00
Underground	1	$6,675.12	$400,507.01	$27,522.00
TOTALS:		$180,573.11	$10,834,391.66	$577,962.00

Municipal Lease (Phase TEN) **Delivery Date:** 3/11/2024 **Pick-up Date:** 3/12/2029	**(A)** **Quantity Required For Phase 10**	**(B)** **Price Per Unit(s) Per Month**	**(C)** **Extended Price Per Unit(s) for Phase 10 Time Period (60 months)**	**(D)** **Extended Allocation for Damages (60 months)**
Specification Type				
Pressure digger	1	$10,454.80	$627,288.30	$27,522.00
48' buckets	4	$23,461.21	$1,407,672.00	$110,088.00
55' buckets	7	$60,100.04	$3,606,001.91	$192,654.00
48' digger tandem axel	2	$22,829.92	$1,369,795.46	$55,044.00
Underground	7	$48,127.59	$2,887,655.82	$192,654.00
50' bucket	1	$7,264.08	$435,844.50	$27,522.00
TOTALS:		$164,973.56	$9,898,413.49	$577,962.00

Municipal Lease (Phase ELEVEN) Delivery Date: 01/12/2026 Pick-up Date: 01/11/2030	(A) Quantity Required For Phase 11	(B) Price Per Unit(s) Per Month	(C) Extended Price Per Unit(s) for Phase 11 Time Period (60 months)	(D) Extended Allocation for Damages (60 months)
Specification Type				
Effer EC685	1	$17,932.60	$1,075,955.76	$27,522.00
55' buckets	1	$9,015.01	$540,900.31	$27,522.00
60' buckets TA60	1	$9,505.90	$570,354.00	$27,522.00
48' buckets	8	$49,268.56	$2,956,111.20	$220,176.00
48' digger single axel	1	$8,765.70	$525,942.00	$27,522.00
50' bucket	2	$15,254.56	$915,273.46	$55,044.00
18ton crane	1	$7,992.59	$479,555.30	$27,522.00
TOTALS:				
		$94,487.77	$5,669,263.27	$330,264.00

ICA 4-5: Referring to the response to ICA 2-9, Attachment ICA 2-9b, what are the present numbers of actual employees for each of the line items? The response should be provided in Excel format.

ANSWER: Refer to Attachment ICA 4-5 for the number of employees as of end of April 2022.

Prepared by: JG

Sponsored by: Jerry Galvan

Title	Number of Employees
Business Systems Analyst	1
Client Relationship Analyst	13
Customer Service Representative	155
Customer Solutions Coordinator	1
IT Application Analyst	1
IT Support Analyst	1
Program Coordinator	4
Quality Improvement Specialist	1
Utility Account Specialist	8
Total	185

ICA 4-6: Referring to the response to ICA 2-11, why does Austin Energy not expect to collect payment on the disputed bill for pole attachments?

ANSWER: This is due to the uncertainty of collecting on AT&T pole attachment bills due to an ongoing dispute and negotiations on an expired contract.

Prepared by: JHO / MG

Sponsored by: Brian Murphy

ICA TC 2-19: With regard to AE's response to ICA 2-5: For how many years are the $8 million per year expected to continue?

ANSWER: Given the magnitude of the eventual costs, Austin Energy expects to continue to set aside $8 million annually towards this obligation for the foreseeable future (and, at a minimum, for the next five years). Austin Energy had a non-nuclear decommissioning study performed in 2015 (see Attachment ICA RFI 2-5). Based on this study, in the 2016 Rate Review Austin Energy requested $19.4 million be set aside annually to fund this obligation (see table below from the 2016 RFP). However, at the conclusion of the 2016 Rate Review, Austin Energy was only allowed $8 million annually toward this obligation and has continued this level of funding since that time.

Work Paper D-1.2.5 in 2016 Rate Review

FERC Acct	Description	Reference	FY 2014	Decommission Costs (1)	Years to Amortize	Calculated Expense	Adjustment
			(A)	(B)	(C)	(D)	(E)
						(B) / (C)	(D) - (A)
506	Decker Units 1 and 2		$ -	$ 28,000,000	2	$ 14,000,000	$ 14,000,000
506	Fayette Power Plant		-	30,000,000	8	3,750,000	3,750,000
549	Sand Hill Energy Center		-	22,000,000	13	1,692,308	1,692,308
			$ -	$ 80,000,000		$ 19,442,308	$ 19,442,308