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

AUSTIN ENERGY'S RESPONSE TO INDEPENDENT CONSUMER ADVOCATE'S SECOND REQUEST FOR INFORMATION

Austin Energy files this Response to the Independent Consumer Advocate's ("ICA") Second Request for Information ("RFI") submitted on April 29, 2022. Pursuant to the 2022 Austin Energy Base Rate Review Procedural Guidelines § F(2)(f)(1), this Response is timely filed.

Respectfully submitted,

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ATTORNEYS FOR THE CITY OF AUSTIN D/B/A AUSTIN ENERGY

ICA 2-1: Referring to Appendix C, Page C-66, please provide the actual principal payments for Fiscal Year 2019 and 2020 and forecasted for Fiscal Years 2023 and 2024.

ANSWER: Principal payments (accrual basis) for Fiscal Years 2019 and 2020 are as follows:

2019	$66,362,395
2020	$78,411,895

For the purposes of this response, Austin Energy assumes the forecasted payments requested reflect the scheduled payments for currently issued debt.

Scheduled ("forecasted") principal payments (accrual basis) for Fiscal Years 2023 and 2024 are as follows:

2023	$86,248,225
2024	$93,783,377

Prepared by: MG

Sponsored by: Monica Gonzalez

ICA 2-2: Referring to Appendix C, Page C-66, please explain why the decrease in Total Debt Service allocated to Non-Electric from FY 2021 to FY 2022 is greater than the total decrease in Total Debt Service from FY 2021 to FY 2022.

ANSWER: Debt for electric plants and non-electric plants are issued separately and have varying principal repayment schedules.

Prepared by: MG

Sponsored by: Monica Gonzalez

ICA 2-3: Referring to Appendix C, Page C-69, please provide the actual GFT as a percentage of revenues for Fiscal Years 2019 through 2021 and forecasted for Fiscal Year 2022. The response should provide all supporting workpapers and calculations.

ANSWER:

Fiscal Year	GFT as % of Total Operating Revenue
2019	7.6% ($110,000,000 / $1,447,299,734)
2020	8.1% ($111,000,000 / $1,373,556,238)
2021	9.0% ($114,000,000 / $1,271,808,478)
2022 Budget	7.7% ($114,000,000 / $1,486,294,057)

The total operating revenue data for the FY 2019-2021 numbers listed above can be found on the following webpage:

FY 2019, 2020, and 2021 Financial Reports (see page 32): https://financeonline.austintexas.gov/afo/afo_content.cfm?s=4

The total operating revenue data for the FY 2022 Budget can be found on the following webpage. The general fund transfer amounts for FY 2019-2022 can be found on page 377 on the following webpage: https://financeonline.austintexas.gov/afo/afo_content.cfm?s=1&p=159

Prepared by: MG

Sponsored by: Monica Gonzalez

ICA 2-4: Referring to Appendix C, Pages C-71 and C-72, please explain what the adjustments for "Support Services" represent.

ANSWER: The $47,507,850 adjustment to Support Services on Appendix C, Page C-71, Line 12 is to remove the portion of the three-year average capital spending for Support Services (in column D) that is associated with the new Austin Energy headquarters in Mueller. The identification of the spending on the new headquarters in each year is listed on Line 19 of Page C-71.

The $29,333,333 adjustment to Support Services on Appendix C, Page C-71, Line 42 is to remove the debt funding associated with the new Austin Energy headquarters. This amount is equal to $88 million divided by three (to make a three-year average).

The $70,402,827 adjustment to Support Services on Appendix C, Page C-72, Line 79 is simply the difference between the 50% assumed level of cash funding for FY 2021 capital spending (i.e., $168,446,082 x 50%) and the Test Year amount based on 50% cash funding of the three-year average capital spending without the new Austin Energy headquarters.

Thus, in summary, all adjustments to Support Services on Pages C-71 and C-72 of Appendix-C are related to the removal of the new Austin Energy headquarters from the Test Year.

Prepared by: GR

Sponsored by: Grant Rabon

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 www.newgenstrategies.net

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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	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

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

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	$ 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.

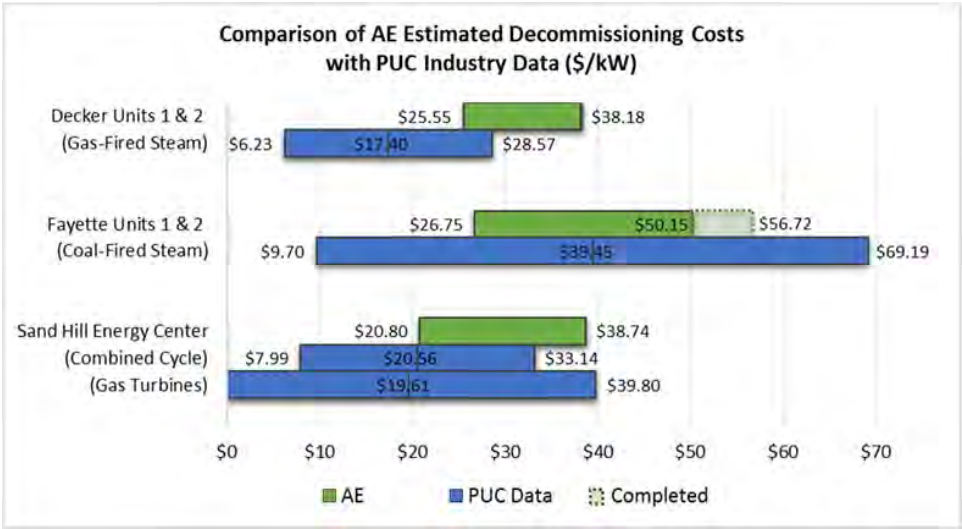
Table 5 shows the estimated decommissioning costs for Decker Units 1 and 2, Fayette Units 1 and 2, and Sand Hill Energy Center expressed on a dollars per kW basis based on the data conveyed in Tables 1, 2, and 3. Note the range listed for Fayette Units 1 and 2 does not include work already completed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

Appendix A
Decker Creek Power Station
Plant Decommissioning Cost Estimate
(Detailed Site Specific Analysis)

App I

I-105

Submitted to
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Austin, TX 78731

Submitted by
AECOM
400 W. 15th Street,
Suite 600
Austin, TX 78701
July 10, 2015

Decker Creek Power Station
Plant Decommissioning Cost Estimate

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1 Introduction

This report presents the decommissioning and demolition cost estimate prepared by AECOM Technical Services, Inc. (AECOM) for NewGen Strategies & Solutions for the Austin Energy (AE) Decker Creek Power Station located in Austin, Texas. The Decker Creek Power Station is a 927 megawatt natural gas power plant that was constructed between 1967 and 1978 and initially utilized fuel oil. Units 1 and 2, which were included in the decommissioning scope and cost estimate, have a total capacity of 726 megawatts. A vicinity map depicting the location of the Decker Creek Power Plant Station is provided in Figure 1.

The decommissioning and demolition cost estimate was prepared following AECOM's Estimate Classification System based on the AACE International system to develop a Budget/Authorization/Control (Level 3) estimate. The decommissioning cost estimate was prepared for the removal of the Unit 1 & Unit 2 turbine generator and boiler buildings and supporting structures as well as other buildings and equipment delineated in this report. Encotech Engineering Consultants, a subcontractor to NewGen Strategies & Solutions was utilized to provide the concrete quantities for disposal and the steel quantities for scrap value credit.

2 Cost Estimate

To prepare the cost estimate, AECOM initially completed a desktop review of the drawings and other site files provided by AE on the Decker Creek Power Station. After the desktop review, a site visit was completed with AE personnel so the layout of the individual buildings and equipment to be decommissioned could be observed. During the site visit, the buildings and equipment to be included in the decommissioning cost estimate was discussed in detail with AE personnel.

Based on the desktop review and site visit, a task list was prepared for the decommissioning activities. The list was prepared to provide a general description of each major task to be completed as part of the decommissioning and demolition. The task list served as the basis of the estimate and was used as the work breakdown structure (WBS) for preparing the decommissioning cost estimate.

Once the task list and work breakdown structure (WBS) was developed, 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 power plants. AECOM utilized the SageTimberline Estimating software which is an open conductive (ODBC) system to develop the cost estimate. The software was supplemented with AECOM's developed and maintained database, consisting of over 75,000 items, which was used to provide current pricing and area cost factors. In addition, AECOM solicited input from contractors that we have used in the past to validate some of the key pricing elements.

After the cost estimate was developed, AECOM utilized a risk register to determine an appropriate level of contingency allowance that should be included in the estimate at the task level.

2.1 Desktop Review

As part of the desktop review, AECOM reviewed existing documentation for the Decker Creek Power Station provided by AE. The information reviewed included building construction drawings and floor plans, site plans, and a previous asbestos and hazardous materials inspection report. Note that quantities of hazardous materials, including asbestos containing materials (ACM) are not available for the Decker Creek Power Station. Therefore, as part of the desktop review, AECOM reviewed the quantities of hazardous materials removed and disposed for the Holly Plant which is of a similar age and design as Decker.

2.2 Site Inspection

After completing the desktop review, a site inspection was completed by AECOM of the Decker Creek Power Station on Wednesday, March 18, 2015. AECOM was accompanied by Rogelio Zavala, who is AE's Power System Engineer for the Decker Creek Power Station. During the site inspection, the scope of the buildings and equipment to be included in the decommissioning cost estimate was defined. In addition, AECOM personnel observed the type of construction and configuration of the various portions of the plant and that was used in developing the assumed demolition methods and procedures used in the cost estimate.

A second site inspection was completed by AECOM and Encotech on Friday, April 10, 2015. The second site inspection was to allow Encotech to visually inspect the buildings and equipment to be included in their concrete and steel volume estimates. AECOM and Encotech were accompanied by Steve Wotruba, who is AE's Plant Manager for the Decker Creek Power Station.

2.3 Task List and Work Breakout Structure

Based on the desktop review and site inspections, a task list was prepared for the decommissioning and demolition of the Decker Creek Power Station. The list was prepared to provide a general description of each major task to be completed as part of the decommissioning and demolition activities. The task list served as the basis of the cost estimate and was prepared based on the following information:

- Existing plant documentation;
- Site inspection;
- Identified or potential presence of hazardous materials;
- Decommissioning and demolition approach to:
    - Building/Structures
    - Salvage
    - Scrap
    - Recyclable materials
    - Disposal
- Sequencing approach to:
    - Hazardous materials characterization, abatement, disposal
    - Equipment salvage
    - Building deconstruction
    - Scrap materials
    - Off-site disposal

The following provides the items included and associated assumptions for each of the Level 1 tasks within the WBS. During the development of the cost estimate, AECOM coordinated with AE to define the scope of work and associated assumptions in preparing the detailed cost estimate. The agreed upon assumptions for the detailed cost estimate are discussed below for each task and are provided in Appendix A.

Note that additional owner's costs as discussed in Section 2.4 were included in the overall decommissioning project cost estimate. The owner's costs provided were not prepared as part of the detailed cost estimate. Rather they were scaled from actual costs provided by AE from a similar power plant decommissioning project.

2.3.1 Task 1 - Contractor Field OH & General Conditions

Task 1 contains costs for the contractor to complete the work including:

- Temporary facilities for a project office;
- Power requirements necessary to complete work;
- Water connection and toilet facilities;

- Construction of a truck wash area;
- Obtaining the necessary permits;
- Preparation of work plans and submittals as needed;
- Site security provisions including utilizing temporary chain link fencing and concrete barriers, and;
- On-site project management and safety personnel.

Note that the cost estimate assumes a total project duration of 60 weeks to complete all the decommissioning and demolition activities.

2.3.2 Task 2 - Mobilization

Task 2 includes costs to mobilize to the project site all construction equipment and field personnel.

2.3.3 Task 3 - Environmental Controls

Task 3 contains costs for implementing all the necessary environmental controls to complete the work including:

- Temporary erosion and sediment control features;
- Air monitoring;
- Sampling and testing;
- Dust control provisions, and
- Noise and vibration monitoring.

2.3.4 Task 4 - Hazardous Materials Abatement Allowances

Task 4 includes costs for management of hazardous materials as part of the decommissioning activities including asbestos contain materials (ACM), polychlorinated biphenyls (PCBs), mercury, and hazardous liquids.

Hazardous materials surveys and quantity calculations have not been completed for the Decker Creek Power Station. Because the Holly Power Plant and Decker Creek Power Station were constructed in the same time period and are similar in size, actual quantities of hazardous materials for the Holly Power Plant Decommissioning Project provided in the *Building Decommissioning Report* prepared by Weston Solutions, Inc. dated April 2014 were used for this estimate.

Based on comments provided by AE on our cost estimate assumptions for Decker Creek Power Station, a baseline soil and groundwater investigation was included in the decommissioning cost estimate. The investigation would be used to determine baseline conditions of soil and groundwater after the decommissioning activities are completed so that appropriate future use of the area could be evaluated. Note that soil and groundwater remediation costs, if necessary, have not been included as part of the detailed cost estimate.

2.3.5 Task 5 - Plant Equipment & Piping Decommissioning & Cleaning

Task 5 includes costs for completing the following activities:

- [redacted];

- [redacted];
- [redacted];
- [redacted];
- [redacted].

The cost estimate assumes all piping and equipment to be removed as part of the decommissioning activities will be de-energized, de-oiled, and isolated by Decker Plant personnel. Therefore, the detailed cost estimate only includes costs to verify, flush, and clean residual liquids as needed.

2.3.6 Task 6 - Demolition

Task 6 includes costs to demolish the following items:

- [redacted];
- [redacted];
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

2.3.7 Task 7 - Site Restoration

Task 7 includes costs to restore the decommissioning areas. Site restoration activities include backfilling [redacted] with clean off-site fill after removal. The estimate

assumes the final restored surface will consist of crushed stone [redacted] and topsoil and seeding [redacted]. Restoration activities include leveling the earthen berms [redacted].

2.3.8 Task 8 – Recycling and Salvage

Task 8 includes the credit for salvage costs of steel and other metals that will be generated as part of the decommissioning activities. As noted in the detail cost estimate provided in Appendix D, salvage credit value used for steel in this cost estimate was $130/ton.

2.3.9 Task 9 - Demobilization

Task 9 includes costs to demobilize all construction equipment and field personnel from the project site.

2.4 Owner's Costs

To estimate the total costs associated with the decommissioning of the Decker Creek Power Plant, AECOM solicited input from AE on owner's costs from similar projects completed. The owner's costs provided by AE were scaled and applied as appropriate to the Decker Creek Power Plant. Owner's costs are summarized in Section 2.6.

2.5 Risk Register

To assign appropriate contingencies, AECOM prepared a risk register in accordance with AACE International Recommended Practice No. 40R-08 "Contingency Estimating". The risk register allows for a quantitative evaluation of the potential impact of each item catalogued on the risk register by calculating the product of the consequence (i.e., dollars or duration) and the probability of occurrence. 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 risk register prepared for the Decker Creek Power Plant decommissioning activities is presented in Appendix C.

2.6 Summary of Estimate Costs

As indicated in the table below, the estimated detailed decommissioning costs for the Decker Creek Power Plant are $11,131,374. Note that the detailed decommissioning cost estimate is in today's dollars and does not include owner's costs. With the estimated owner's costs included, the total decommissioning costs for the Decker Creek Power Plant are estimated to range between $19,761,374 to $27,321,374. The detailed demolition cost estimate is provided in Appendix D.

Table 1: Summary of Decker Creek Power Plant Decommissioning Cost Estimate

Detailed Decommissioning Cost Estimate

Task	Description	Estimated Costs
1	Contractor Field OH & General Conditions	[redacted]
2	Mobilization	[redacted]
3	Environmental Controls	[redacted]
4	Hazardous Materials Abatement Allowances	[redacted]
5	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]
6	Demolition	[redacted]
7	Site Restoration	[redacted]
8	Recycling & Salvaging	[redacted]
9	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 (15%-30%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($200,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Costs	**$18,551,374**	**$27,721,374**

Figures

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Appendix A.
Cost Estimate Scope of Work Assumptions and Basis of Estimate, Decker Power Plant

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Appendix B.
Decker Power Plant Decommissioning, Opinion of Material Quantities, ENCOTECH

Decker Power Plant Decommissioning
Opinion of Material Quantities

Prepared for:

AECOM
400 W. 15th Street
Suite 600
Austin, Texas 78701

Prepared by:

Encotech Engineering Consultants
8500 Bluffstone Cove, Suite B-103
Austin, Texas 78759

Firm Registration No. 1141

May 4, 2015

May 4, 2015

Craig Niedermeier, P.E.
Program Manager / Senior Project Manager
AECOM
400 W. 15th Street
Suite 600
Austin, Texas 78701

Re: **Decker Power Plant Decommissioning**
Material Quantities Estimate

Dear Mr. Niedermeier;

Encotech was tasked with the development of quantity estimates for the decommissioning of the Decker Creek Power Station. The quantities developed are broken up into steel scrap and concrete for disposal. Encotech has reviewed the site and structural drawings and has determined the total steel scrap tonnage and concrete volume to be approximately 2563 tons, and 12702 yd^3 respectively.

The following buildings were included in the estimate.

- [redacted]

The focus of this review was the main structural steel and concrete quantities and as such, miscellaneous steel quantities were not determined and are excluded from this report. The quantities are reported by building in Table 1.

Table 1: Steel & Concrete Quantities by Building

Building	Concrete (Cubic Yds)	Structural Steel (Tons)	Reinforcing Steel (Tons)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
Total	12702	2017	546

Calculation Procedure

Encotech reviewed the structural and site drawings to determine the quantity of materials. Values for each building were determined using the following steps:

Concrete

1. The quantity and volume of each type of footing was determined
2. The length of each type of grade beam shown on plan was determined.
3. The volume of concrete in the grade beams was determined based on the cross section of each type of grade beam
4. The areas of the slab at each level were determined from the plans and the volume of each slab was determined based on the section cuts
5. The volume of the concrete columns was determined using the building sections and the details
6. The reinforcement volume was determined by taking the average reinforcement ratio of each type of structure (footing, slab, column, grade beam, etc.) and multiplying buy the total concrete volume of structures in that type. This volume was then multiplied by the density of steel to determine the total reinforcement weight.

Steel

1. The total length of each steel beam/column type was determined based on the structural drawings for each level
2. The weight per linear foot of each beam/column type was multiplied by the total length for that type and the results were summed to determine the total weight of structural steel.

The above procedure was used for each building type except for [redacted]. The structural and concrete drawings for [redacted] were only partially legible so the material quantities for [redacted] were based on the material per square foot of [redacted] This will yield approximate values for bot steel and concrete due to [redacted] designed by the same firm in a relatively short amount of time.

The material values for the [redacted] were determined based on the volume of steel of a ¾" x 30' tall tank with the diameter shown on the plans. The concrete and rebar volumes were based on the plan and details shown on the structural drawings and the reinforcement ratio of the support ring.

The spreadsheets used to determine the material quantities for each building are shown in Appendix A.

Sincerely,

Carl Holiday
Senior Project Manager

Appendix A: Calculation Spreadsheets

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Appendix C.
Decker Creek Power Station Risk Register

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Appendix D
Decker Creek Power Station
Decommissioning Cost Estimate

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Appendix B
Fayette Power Project and Sand Hill Energy Center
Plant Decommissioning Cost Estimate
(Benchmark Analysis)

AECOM
400 West 15th Street, Suite 600
Austin, Texas 78701

512.472.4519 tel
512.472.7519 fax

July 10, 2015

Grant Rabon
NewGen Strategies & Solutions
3409 Executive Center Drive
Suite 128
Austin, Texas 78731

Subject: Benchmarking Cost Estimate
Fayette Power Project and Sand Hill Energy Center

Dear Mr. Rabon,

This letter report presents the benchmark decommissioning and demolition cost estimates prepared by AECOM Technical Services, Inc. (AECOM) for NewGen Strategies & Solutions for the Austin Energy (AE) Fayette Power Project located in La Grange, Texas and the Sand Hill Energy Center located in Austin, Texas. The benchmark estimate approach presented in this letter provides an estimate of the decommissioning costs for the Fayette Power Project and Sand Hill Energy Center based on scaled costs from actual decommissioning costs for similar power plants.

The Fayette Power Project is a 1,625 net megawatt coal fired power plant that was constructed between 1979 and 1980. AE shares 50% ownership of Units 1 and 2 at the Fayette Power Project with the Lower Colorado River Authority (LCRA). Both Units 1 and 2 have a capacity of 590 megawatts or a total capacity of 1,180 megawatts. The Sand Hill Energy Center is a 570 megawatt natural gas, combined cycle power plant that was constructed between 2001 and 2010.

For the benchmark decommissioning cost estimate, AECOM prepared estimates for the following identified major decommissioning tasks for the Fayette Power Project and Sand Hill Energy Center:

1. Contractor Field OH & General Conditions
2. Mobilization
3. Environmental Controls
4. Hazardous Materials Abatement
5. Plant Equipment & Piping Decommissioning & Cleaning
6. Demolition
7. Site Restoration
8. Demobilization

The benchmark estimates at each power plant for each of these identified major tasks were prepared by scaling on a dollar per kilowatt basis from decommissioning costs from similar power

plants. In addition, AECOM incorporated available plant specific information including equipment and building lists, site layouts, and potential presence of hazardous materials based on age of the plant. The equipment lists for the Fayette Power Project and Sand Hill Energy Center are listed in Attachment A.

To estimate the total costs associated with the decommissioning of the Fayette Power Project and Sand Hill Energy Center, AECOM solicited input from AE on owner's costs from other power plant decommissioning projects completed. The actual owner's costs provided by AE were used to estimate owner's costs for the benchmark estimates.

The attached tables provide the benchmark cost estimates for the Fayette Power Project and the Sand Hill Energy Center power plants. A list of the assumptions used in the development of the benchmark cost estimates are provided below each table.

For the Fayette Power Project, only Units 1 and 2 and the common areas for Units 1, 2, and 3 as identified in the attached equipment list was included in the benchmark cost estimate. In addition, the percentage of ownership of Austin Energy was applied to the benchmark cost estimate at a rate of 50% for Units 1 and 2 and 36% for the common items for Units 1, 2, and 3 as noted on the attached equipment and building list.

For the Sand Hill Energy Center benchmark cost estimate, all the equipment listed in the attached equipment list was included in the benchmark cost estimate. For this plant, it was assumed Austin Energy has 100% ownership.

Yours sincerely,

Craig Niedermeier, P.E.
Project Manager

cc: Fred Dymek, AECOM
Greg Sampson, VERTEX

Attachment A
Equipment Lists

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Attachment B
Benchmark Cost Estimates

Fayette Power Plant
Austin Energy

AECOM

Task	Description	Total Project Cost	
		Low Range Estimate	High Range Estimate
1	Contractor Field OH & General Conditions	$ [redacted]	$ [redacted]
2	Mobilization	$ [redacted]	$ [redacted]
3	Environmental Controls	$ [redacted]	$ [redacted]
4	Hazardous Materials Abatement	$ [redacted]	$ [redacted]
5	Plant Equipment & Piping Decommissioning and Cleaning	$ [redacted]	$ [redacted]
6	Demolition	$ [redacted]	$ [redacted]
7	Site Restoration	$ [redacted]	$ [redacted]
8	Recycling and Salvage	$ [redacted]	$ [redacted]
9	Demobilization	$ [redacted]	$ [redacted]
	Contingency (30%)	$ [redacted]	$ [redacted]
	Demolition Subtotal Costs	$ 20,150,000	$ 34,260,000

Other Estimated Project Costs

Task	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**

Notes/Assumptions:

1. This is a 'scaled' estimate based on other actual power plant decommissioning and demolition cost estimates (a 90 MW, 400 MW, 1100 MW coal power plants of similar vintage). Note that there are a number of plant-specific data that would need to be reviewed and factored into this cost estimate to develop a more accurate estimate of the actual/anticipated costs.
2. Estimate assumes no bonding and non-union labor.
3. Estimate assumes a 18 month duration (low range) and 24 month (high range).
4. ACM and other regulated materials costs are based on similar plants.
5. Costs assume 50% AE ownership for Units 1 and 2 and 36% ownership of common buildings equipment. Costs do not include decommissioning of Unit 3 but does include any equipment/buildings shared by all three units (i.e. coal handling equipment). Costs also assume decommissioning as part of entire plant decommissioning.
6. Equipment included in the estimate are provided in the equipment list for this report.
7. Salvage credit not included in 30% contingency.
8. Owner's costs based on actual costs from a AE power plant decommissioning project.
9. Soil and groundwater remediation costs assume [redacted]. Costs assume closure of [redacted], [redacted], and [redacted] as well as address general environmental issues.

Sand Hill Energy Center
Austin Energy

AECOM

Task	Description	Total Project Cost	
		Low Range Estimate	High Range Estimate
1	Contractor Field OH & General Conditions	$ [redacted]	$ [redacted]
2	Mobilization	$ [redacted]	$ [redacted]
3	Environmental Controls	$ [redacted]	$ [redacted]
4	Hazardous Materials Abatement	$ [redacted]	$ [redacted]
5	Plant Equipment & Piping Decommissioning and Cleaning	$ [redacted]	$ [redacted]
6	Demolition	$ [redacted]	$ [redacted]
7	Site Restoration	$ [redacted]	$ [redacted]
8	Recycling and Salvage	$ [redacted]	$ [redacted]
9	Demobilization	$ [redacted]	$ [redacted]
	Contingency (30%)	$ [redacted]	$ [redacted]
	Demolition Subtotal Costs	$ 5,716,000	$ 10,382,000

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	$ 11,856,000	$ 22,082,000

Notes/Assumptions:

1. This is a 'scaled' estimate based on our Decker Creek Power Station decommissioning and demolition cost estimate. There are a number of plant-specific data that would need to be reviewed and factored into this cost estimate to develop a more accurate estimate of the actual/anticipated costs.
2. Estimate assumes no [redacted] based on construction date of plant.
3. Estimate assumes no bonding and non-union labor.
4. Estimate assumes a 9 month duration.
5. Equipment included in the estimate are provided in the equipment list for this report.
6. Salvage credit not included in 30% contingency.
7. Owner's costs based on actual costs from a similar AE power plant decommissioning project.

Appendix C
Survey of Public Utility Commission Proceedings Regarding Non-Nuclear Decommissioning Costs

Survey of Public Utility Commission Proceedings Regarding
Non-Nuclear Power Plant Dismantling Costs Database by Plant Type

Plant Descriptions							Project Costs Approved					Project Costs Requested				
Power Plant	Utility	Type Description	Size (MW)	Location	Actual or Estimated	Year Estimated	Total Project	$/kW	Dismantling Costs	Contingency	Salvage	Total Project	$/kW	Dismantling Costs	Contingency	Salvage
Coal-Fired Steam																
Lansing Smith 1 and 2 and Common	Gulf Power	Coal Fired	305	Florida	Estimated	2013	Decision pending					$ 30,383,000	$ 99.62	n/a	n/a	n/a
Scholz 1 and 2	Gulf Power	Coal Fired	80	Florida	Estimated	2013	Decision pending					$ 11,431,000	$ 142.89	n/a	n/a	n/a
Daniel 1 and 2 and Common	Gulf Power, et al	Coal Fired	1000	Mississippi	Estimated	2013	Decision pending					$ 31,543,000	$ 31.54	n/a	n/a	n/a
Scherer 3 and Common	Gulf Power, et al	Coal Fired	818	Georgia	Estimated	2013	Decision pending					$ 63,091,000	$ 77.13	n/a	n/a	n/a
Breed (Dismantled 1994-2006)	Indiana Michigan Power Company	Coal Fired	400	Indiana	Actual	2005	$ 10,766,584	$ 26.92	$ 12,090,704	$ -	$ (1,324,120)	$ 28,663,000	$ 71.66	$ 25,020,000	$ 5,733,000	$ (2,090,000)
Rockport	Indiana Michigan Power Company	Coal Fired	2600	Indiana	Estimated	2011	$ 27,953,280	$ 10.75	Commission approved 40% based on historical estimated to actual			$ 69,883,200	$ 26.88	$ 71,962,800	$ 17,299,300	$ (19,378,900)
Tanners Creek	Indiana Michigan Power Company	Coal Fired	995	Indiana	Estimated	2011	$ 19,101,880	$ 19.20	Commission approved 40% based on historical estimated to actual			$ 47,754,700	$ 47.99	$ 49,388,440	$ 5,175,760	$ (6,809,500)
Reid Gardner 1, 2, and 3	NV Energy	Coal Fired	557	Nevada	Estimated	2014	Decision pending					$ 45,400,000	$ 81.51	$ 48,200,000	$ 7,200,000	$ (10,000,000)
Navajo	NV Energy, et al	Coal Fired	2250	Arizona	Estimated	2008	Not available					$ 93,061,000	$ 41.36	$ 106,777,664	$ 12,138,336	$ (25,855,000)
Arapahoe	Public Service Company of Colorado	Coal Fired	246	Colorado	Estimated	2014	$ 34,781,000	$ 141.39	$ 32,790,000	$ 5,703,000	$ (3,712,000)	$ 34,781,000	$ 141.39	$ 32,790,000	$ 5,703,000	$ (3,712,000)
Cameo	Public Service Company of Colorado	Coal Fired	73	Colorado	Estimated	2011	$ 3,650,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 14,825,838	$ 203.09	$ 19,284,438	$ 297,006	$ (4,755,606)
Cherokee	Public Service Company of Colorado	Coal Fired	694	Colorado	Estimated	2014	$ 34,700,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 48,588,000	$ 70.01	$ 48,036,000	$ 8,354,000	$ (7,802,000)
Comanche	Public Service Company of Colorado	Coal Fired	1488	Colorado	Estimated	2014	$ 74,400,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 66,462,000	$ 44.67	$ 70,963,000	$ 12,341,000	$ (16,842,000)
Craig	Public Service Company of Colorado	Coal Fired	856	Colorado	Estimated	2014	$ 42,800,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 83,908,000	$ 98.02	$ 81,009,000	$ 14,089,000	$ (11,190,000)
Hayden	Public Service Company of Colorado	Coal Fired	446	Colorado	Estimated	2014	$ 22,300,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 47,289,000	$ 106.03	$ 45,234,000	$ 7,867,000	$ (5,812,000)
Pawnee	Public Service Company of Colorado	Coal Fired	505	Colorado	Estimated	2014	$ 25,250,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 71,013,000	$ 140.62	$ 65,443,000	$ 11,381,000	$ (5,811,000)
Valmont	Public Service Company of Colorado	Coal Fired	186	Colorado	Estimated	2014	$ 9,300,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 30,630,000	$ 164.68	$ 30,679,000	$ 28,000	$ (77,000)
Zuni	Public Service Company of Colorado	Coal Fired	107	Colorado	Estimated	2014	$ 5,350,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 21,876,000	$ 204.45	$ 20,881,000	$ 3,631,000	$ (2,636,000)
Mohave Generating Station	Southern California Edison, et al	Coal Fired	1580	Nevada	Actual/Estimated	2009	$ 57,121,570	$ 36.15	$ 63,071,938	$ 4,728,571	$ (10,678,939)	$ 57,121,570	$ 36.15	$ 63,071,938	$ 4,728,571	$ (10,678,939)
Harrington	Southwestern Public Service Company	Coal Fired	1041	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 29,755,120	$ 28.58	$ 46,555,305	$ 7,109,370	$ (23,909,555)
Tolk	Southwestern Public Service Company	Coal Fired	1080	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 35,775,533	$ 33.13	$ 50,409,156	$ 7,502,506	$ (22,136,129)
J. Robert Welsh Units 1-3	SWEPCO	Coal Fired	1584	Texas	Estimated	2012	$ 915,759	$ 0.58	$ 21,124,841	$ 7,294,300	$ (27,503,382)	$ 915,759	$ 0.58	$ 21,124,841	$ 7,294,300	$ (27,503,382)
Dolet Hills Unit 1	SWEPCO, et al	Lignite Fired	640	Louisiana	Estimated	2012	$ 17,740,834	$ 27.72	$ 25,802,381	$ 5,976,000	$ (14,037,547)	$ 17,740,834	$ 27.72	$ 25,802,381	$ 5,976,000	$ (14,037,547)
Flint Creek Unit 1	SWEPCO, et al	Coal Fired	528	Arkansas	Estimated	2012	$ 4,923,094	$ 9.32	$ 11,430,051	$ 3,165,500	$ (9,672,457)	$ 4,923,094	$ 9.32	$ 11,430,051	$ 3,165,500	$ (9,672,457)
Henry W. Pirkey Unit 1	SWEPCO, et al	Lignite Fired	675	Texas	Estimated	2012	$ 12,819,548	$ 18.99	$ 21,613,735	$ 5,366,000	$ (14,160,187)	$ 12,819,548	$ 18.99	$ 21,613,735	$ 5,366,000	$ (14,160,187)
John D. Turk Unit 1	SWEPCO, et al	Coal Fired	600	Arkansas	Estimated	2012	$ 14,324,345	$ 23.87	$ 25,349,988	$ 6,419,200	$ (17,444,843)	$ 14,324,345	$ 23.87	$ 25,349,988	$ 6,419,200	$ (17,444,843)
Big Bend	Tampa Electric	Coal Fired	1700	Florida	Estimated	2011	$ 58,809,000	$ 34.59	$ 70,367,650	$ 8,821,350	$ (20,380,000)	$ 58,809,000	$ 34.59	$ 70,367,650	$ 8,821,350	$ (20,380,000)
Gas-Fired Steam																
Cape Canaveral	Florida Power and Light	Gas Fired	804	Florida	Estimated	2009	$ 16,147,799	$ 20.08	$ 19,991,978	$ 2,583,648	$ (6,427,827)	$ 16,147,799	$ 20.08	$ 19,991,978	$ 2,583,648	$ (6,427,827)
Manatee Plant Units 1-2	Florida Power and Light	Gas Fired	1727	Florida	Estimated	2009	$ 40,445,467	$ 23.42	$ 45,962,803	$ 6,471,275	$ (11,988,611)	$ 40,445,467	$ 23.42	$ 45,962,803	$ 6,471,275	$ (11,988,611)
Martin Plant Units 1-2	Florida Power and Light	Gas/Oil Fired	1727	Florida	Estimated	2009	$ 35,788,752	$ 20.72	$ 42,946,717	$ 5,726,200	$ (12,884,165)	$ 35,788,752	$ 20.72	$ 42,946,717	$ 5,726,200	$ (12,884,165)
Port Everglades	Florida Power and Light	Gas Fired/Gas Turbine	1666	Florida	Estimated	2009	$ 59,168,348	$ 35.52	$ 60,607,065	$ 9,466,936	$ (10,905,653)	$ 59,168,348	$ 35.52	$ 60,607,065	$ 9,466,936	$ (10,905,653)
Cunningham	Southwestern Public Service Company	Gas Fired	485	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 13,051,957	$ 26.91	$ 18,156,965	$ 2,943,713	$ (8,048,721)
Jones	Southwestern Public Service Company	Gas Fired	824	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 19,832,386	$ 24.07	$ 25,425,215	$ 4,068,928	$ (9,661,757)
Maddox	Southwestern Public Service Company	Gas Fired/Gas Turbine	188	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,712,328	$ 51.66	$ 11,409,544	$ 1,844,861	$ (3,542,077)
Moore County	Southwestern Public Service Company	Gas Fired	73	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,129,118	$ 125.06	$ 9,743,359	$ 1,690,341	$ (2,304,582)
Nichols	Southwestern Public Service Company	Gas Fired	457	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 22,040,027	$ 48.23	$ 26,667,245	$ 4,492,243	$ (9,119,461)
Plant X	Southwestern Public Service Company	Gas Fired	442	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 21,299,223	$ 48.19	$ 27,646,173	$ 4,670,354	$ (11,017,304)
Knox Lee Units 1-5	SWEPCO	Gas Fired	488	Texas	Estimated	2012	$ 6,347,197	$ 13.01	$ 13,189,052	$ 3,534,900	$ (10,376,755)	$ 6,347,197	$ 13.01	$ 13,189,052	$ 3,534,900	$ (10,376,755)
Lieberman Units 1-4	SWEPCO	Gas Fired	268	Louisiana	Estimated	2012	$ 881,508	$ 3.29	$ 5,043,128	$ 1,624,400	$ (5,786,020)	$ 881,508	$ 3.29	$ 5,043,128	$ 1,624,400	$ (5,786,020)
Lone Star Unit 1	SWEPCO	Gas Fired	50	Texas	Estimated	2012	$ 1,084,049	$ 21.68	$ 1,921,421	$ 486,800	$ (1,324,172)	$ 1,084,049	$ 21.68	$ 1,921,421	$ 486,800	$ (1,324,172)
Wilkes Units 1-3	SWEPCO	Gas Fired	901	Texas	Estimated	2012	$ 1,330,374	$ 1.48	$ 933,900	$ 3,389,700	$ (2,993,226)	$ 1,330,374	$ 1.48	$ 933,900	$ 3,389,700	$ (2,993,226)
Gas Turbine																
Cutler	Florida Power and Light	Gas Turbine	237	Florida	Estimated	2009	$ 10,095,581	$ 42.60	$ 11,310,568	$ 1,615,293	$ (2,830,280)	$ 10,095,581	$ 42.60	$ 11,310,568	$ 1,615,293	$ (2,830,280)
Blue Spruce	Public Service Company of Colorado	Gas Turbine	310	Colorado	Estimated	2014	$ 12,400,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 4,842,000	$ 15.62	$ 5,116,000	$ 890,000	$ (1,164,000)
Carlsbad	Southwestern Public Service Company	Gas Turbine	11	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 495,039	$ 45.00	$ 495,617	$ 74,343	$ (74,921)
Maddox 2	Southwestern Public Service Company	Combustion Gas Turbine	60	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,712,328	$ 161.87	$ 11,409,544	$ 1,844,861	$ (3,542,077)
Riverview	Southwestern Public Service Company	Combustion Gas Turbine	23	Texas	Estimated	2012	Decision pending, study used in cases for both Texas and New Mexico					$ 2,964,659	$ 128.90	$ 3,151,102	$ 467,728	$ (654,171)
Harry D. Mattison Units 1-4	SWEPCO	Combustion Gas Turbine	304	Arkansas	Estimated	2012	$ 3,350,299	$ 11.02	$ 3,693,551	$ 712,300	$ (1,055,552)	$ 3,350,299	$ 11.02	$ 3,693,551	$ 712,300	$ (1,055,552)
J. Lamar Stall	SWEPCO	Combustion Gas Turbine	507	Louisiana	Estimated	2012	$ 124,864	$ 0.25	$ 4,275,570	$ 1,486,900	$ (5,637,606)	$ 124,864	$ 0.25	$ 4,275,570	$ 1,486,900	$ (5,637,606)
Bayside	Tampa Electric	Combustion Gas Turbine	1800	Florida	Estimated	2011	$ 7,506,000	$ 4.17	$ 20,586,100	$ 1,125,900	$ (14,206,000)	$ 7,506,000	$ 4.17	$ 20,586,100	$ 1,125,900	$ (14,206,000)
Combined Cycle																
Fort Lauderdale	Florida Power and Light	Combined Cycle	1042	Florida	Estimated	2009	$ 24,721,603	$ 23.73	$ 27,501,811	$ 3,955,456	$ (6,735,664)	$ 24,721,603	$ 23.73	$ 27,501,811	$ 3,955,456	$ (6,735,664)
Fort Myers	Florida Power and Light	Combined Cycle/Gas Turbine	2566	Florida	Estimated	2009	$ 28,682,321	$ 11.18	$ 34,610,305	$ 4,589,171	$ (10,517,155)	$ 28,682,321	$ 11.18	$ 34,610,305	$ 4,589,171	$ (10,517,155)
Manatee Plant Unit 3	Florida Power and Light	Combined Cycle	1150	Florida	Estimated	2009	$ 22,780,807	$ 19.81	$ 23,356,666	$ 3,644,929	$ (4,220,788)	$ 22,780,807	$ 19.81	$ 23,356,666	$ 3,644,929	$ (4,220,788)
Martin Plant Units 3-4, 8	Florida Power and Light	Combined Cycle	1978	Florida	Estimated	2009	$ 31,975,578	$ 16.17	$ 38,307,560	$ 5,116,092	$ (11,448,074)	$ 31,975,578	$ 16.17	$ 38,307,560	$ 5,116,092	$ (11,448,074)
Pea Ridge Cogen	Gulf Power, et al	Combined Cycle	15	Florida	Estimated	2013	$ 150,000	$ 10.00	$ 151,000	$ 14,000	$ (15,000)	$ 151,000	$ 10.07	$ 151,000	$ 14,000	$ (15,000)
Chuck Lenzie	NV Energy	Combined Cycle	1170	Nevada	Estimated	2010	$ 11,919,025	$ 10.19	$ 13,074,731	$ 2,511,254	$ (3,666,960)	$ 23,574,178	$ 20.15	$ 18,160,759	$ 9,080,380	$ (3,666,960)
Harry Allen	NV Energy	Combined Cycle	631	Nevada	Estimated	2010	$ 9,659,172	$ 15.31	$ 9,874,998	$ 1,780,734	$ (1,996,560)	$ 17,731,635	$ 28.10	$ 13,152,130	$ 6,576,065	$ (1,996,560)
Silverhawk	NV Energy	Combined Cycle	560	Nevada	Estimated	2010	$ 4,437,947	$ 7.92	$ 5,214,176	$ 1,057,130	$ (1,833,360)	$ 8,068,673	$ 14.41	$ 6,601,355	$ 3,300,679	$ (1,833,360)
Sunrise	NV Energy	Combined Cycle	152	Nevada	Estimated	2010	$ 4,383,472	$ 28.84	$ 4,455,690	$ 799,042	$ (871,260)	$ 8,464,451	$ 55.69	$ 6,223,807	$ 3,111,904	$ (871,260)
Walter M. Higgins	NV Energy	Combined Cycle	550	Nevada	Estimated	2010	$ 9,479,443	$ 17.24	$ 9,598,086	$ 1,714,717	$ (1,833,360)	$ 18,819,883	$ 34.22	$ 13,768,829	$ 6,884,415	$ (1,833,360)
Ft. St. Vrain	Public Service Company of Colorado	Natural Gas Combined Cycle	965	Colorado	Estimated	2014	$ 38,600,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 24,501,000	$ 25.39	$ 25,593,000	$ 4,451,000	$ (5,543,000)
Rocky Mountain	Public Service Company of Colorado	Natural Gas Combined Cycle	600	Colorado	Estimated	2014	$ 24,000,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 14,804,000	$ 24.67	$ 14,531,000	$ 2,527,000	$ (2,254,000)
Arsenal Hill	SWEPCO	Combined Cycle Natural Gas	110	Louisiana	Estimated	2012	$ 3,081,751	$ 28.02	$ 4,365,075	$ 996,800	$ (2,280,124)	$ 3,081,751	$ 28.02	$ 4,365,075	$ 996,800	$ (2,280,124)
Polk	Tampa Electric	Combined Cycle	940	Florida	Estimated	2011	$ 37,600	$ 0.04	$ 11,567,960	$ 5,640	$ (11,536,000)	$ 37,600	$ 0.04	$ 11,567,960	$ 5,640	$ (11,536,000)
Cherokee Units 5 - 7, CCX2 and Common	Public Service Company of Colorado	Natural Gas Combined Cycle	569	Colorado	Estimated	2014	$ 38,600,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 8,465,000	$ 14.88	$ 9,032,000	$ 1,571,000	$ (2,138,000)

Survey of Public Utility Commission Proceedings Regarding
Non-Nuclear Power Plant Dismantling Costs Database by Plant Type

Notes/Sources

Power Plant	Utility	Project Estimate Source	Final Amount Source
Coal-Fired Steam			
Lansing Smith 1 and 2 and Common	Gulf Power	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Scholz 1 and 2	Gulf Power	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Daniel 1 and 2 and Common	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Scherer 3 and Common	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Breed (Dismantled 1994-2006)	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 42959	Staff Testimony Accepted by Commission pg. 10
Rockport	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 44075	Staff Testimony Accepted by Commission pg. 10
Tanners Creek	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 44075	Staff Testimony Accepted by Commission pg. 10
Reid Gardner 1, 2, and 3	NV Energy	URS Study for NV Energy, Docket 14-05003	
Navajo	NV Energy, et al	Sargent & Lundy Study prepared for SRP, filed as information in NV Docket 11-06007	
Arapahoe	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement approved Arapahoe decomm	
Cameo	Public Service Company of Colorado	TLG Study for CO Docket 11AL-947E	
Cherokee	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Comanche	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Craig	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Hayden	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Pawnee	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Valmont	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Zuni	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Mohave Generating Station	Southern California Edison, et al	2012 SCE Rate Case	2012 Rate Case Final Order
Harrington	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Tolk	Southwestern Public Service Company	TLG Study for TX Docket 43695	
J. Robert Welsh Units 1-3	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Dolet Hills Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Flint Creek Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Henry W. Pirkey Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
John D. Turk Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Big Bend	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Gas-Fired Steam			
Cape Canaveral	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Manatee Plant Units 1-2	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Martin Plant Units 1-2	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Port Everglades	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Cunningham	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Jones	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Maddox	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Moore County	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Nichols	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Plant X	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Knox Lee Units 1-5	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Lieberman Units 1-4	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Lone Star Unit 1	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Wilkes Units 1-3	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Gas Turbine			
Cutler	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Blue Spruce	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Carlsbad	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Maddox 2	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Riverview	Southwestern Public Service Company	TLG Study for TX Docket 40824	
Harry D. Mattison Units 1-4	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
J. Lamar Stall	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Bayside	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Combined Cycle			
Fort Lauderdale	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Fort Myers	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Manatee Plant Unit 3	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Martin Plant Units 3-4, 8	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Pea Ridge Cogen	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Chuck Lenzie	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Harry Allen	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Silverhawk	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Sunrise	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Walter M. Higgins	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Ft. St. Vrain	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Rocky Mountain	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Arsenal Hill	SWEPCO	Sargent & Lundy Study for TX Docket 40443	
Polk	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Cherokee Units 5 - 7, CCX2 and Common	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	

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 2-7: Referring to Appendix C, Page C-111, please provide documentation supporting the annualized cost of new contracts for vegetation management.

ANSWER: In December 2020, the City Council approved contracts to implement a new plan for vegetation management. The plan involves increasing line clearances to enhance reliability and safety and also includes a plan to address overgrowth on the system.

The Test Year adjustment uses the most recent twelve months of payments, if available, under each contract to normalize the Test Year actual payments. Please refer to Attachment ICA RFI 2-7 for workpapers on these calculations.

Attachment ICA RFI 2-7: SD WP D_1_2_10 Vegetation Management K&M

Prepared by: GJ/JO

Sponsored by: Elton Richards

Vegetation Management Known & Measurable Change

Unit	Unit Name	Activity	Activity Name	Object Cod	Object Name	Vendor	Vendor Name	Fiscal Year	FY 2019	FY 2020	FY 2021
3708	Vegetation Management Contractor Inspection-Distribution	5960	Dist Streetlighing Maint	5560	Services-construction contr	ASP7019530	ASPLUNDH TREE EXPERT LLC	Budgeted & Non-Budgeted Expense	$0.00		
3708	Vegetation Management Contractor Inspection-Distribution	5830	Dist OH Line Exp	5560	Services-construction contr	WRI8303917	Wright Tree Service, Inc	Budgeted & Non-Budgeted Expense	0.00	267,891.34	
3708	Vegetation Management Contractor Inspection-Distribution	5930	Dist OH Tree Trimming	5560	Services-construction contr	ASP7019530	ASPLUNDH TREE EXPERT LLC	Budgeted & Non-Budgeted Expense	5,621,306.46	5,624,799.19	4,392,405.55
3708	Vegetation Management Contractor Inspection-Distribution	5930	Dist OH Tree Trimming	5560	Services-construction contr	V00000956693	Davey Resource Group Inc.	Budgeted & Non-Budgeted Expense			1,212,335.74
3708	Vegetation Management Contractor Inspection-Distribution	5930	Dist OH Tree Trimming	5560	Services-construction contr	WRI8303917	Wright Tree Service, Inc	Budgeted & Non-Budgeted Expense	3,679,614.80	3,488,209.81	3,000,437.00
3710	Vegetation Management Contractor Inspection-Transmission	5710	Trans OH Line Maint - AE	5560	Services-construction contr	ASP7019530	ASPLUNDH TREE EXPERT LLC	Budgeted & Non-Budgeted Expense	1,975,305.93	2,213,958.44	1,881,189.08

	FERC		FY 2019	FY 2020	FY 2021	Recent Spend	Known & Measurable Adj
Vegetation Management Contractor Inspection-Transmission	571	Trans OH Line Maint	$1,975,306	$2,213,958	$1,881,189	$2,129,843	$248,654
Vegetation Management Contractor Inspection-Transmission	583	Dist OH Line Exp	0	267,891	0	2,231,795	2,231,795
Vegetation Management Contractor Inspection-Transmission	593	Dist OH Tree Trimming	9,300,921	9,113,009	8,605,178	13,095,347	4,490,168
Vegetation Management Contractor Inspection-Transmission	596	Dist Streetlighing Maint	0	0	0	472,887	472,887
			$11,276,227	$11,594,859	$10,486,367	$17,929,872	$7,443,505

FERC 571 Trans OH Line Maintenance

DO List For NA210000055

Document	Date	Order Amount	Closed Amount	Outstanding	Vendor
DO-1100-21092712606-1	9/27/2021	$296,967.80	$296,967.80	$0.00	ASPLUNDH TREE EX
DO-1100-21092912704-1	9/29/2021	$2,332.80	$0.00	$2,332.80	ASPLUNDH TREE EX
DO-1100-21101200905-1	10/12/2021	$83,851.62	$83,851.62	$0.00	ASPLUNDH TREE EX
DO-1100-21110101883-1	11/1/2021	$181,424.96	$181,424.96	$0.00	ASPLUNDH TREE EX
DO-1100-21112902777-1	11/29/2021	$41,561.66	$41,561.66	$0.00	ASPLUNDH TREE EX
DO-1100-21120903189-1	12/9/2021	$198,544.05	$198,544.05	$0.00	ASPLUNDH TREE EX
DO-1100-22010403806-1	1/4/2022	$120,463.29	$120,463.29	$0.00	ASPLUNDH TREE EX
DO-1100-22012404338-1	1/24/2022	$142,108.31	$142,108.31	$0.00	ASPLUNDH TREE EX
DO-1100-22020904882-1	2/9/2022	$84,552.64	$0.00	$84,552.64	ASPLUNDH TREE EX
	For 6 months		$1,064,922		
	For 12 months		$2,129,843		

FERC 583

DO List For NA200000131

Document	Date	Order Amount	Closed Amount	Outstanding	Vendor
DO-1100-21012204391-1	1/22/2021	$115,457.25	$115,457.25	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21020304803-1	2/3/2021	$33,394.56	$33,394.56	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21030305680-1	3/3/2021	$108,619.81	$108,619.81	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21031706186-1	3/17/2021	$59,183.46	$59,183.46	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21042607579-1	4/26/2021	$84,879.00	$84,879.00	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21050507908-1	5/7/2021	$206,628.68	$206,628.68	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21052008442-1	5/20/2021	$85,677.01	$85,677.01	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21060408866-1	6/4/2021	$102,119.99	$102,119.99	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21062209386-1	6/22/2021	$93,762.01	$93,762.01	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21071910220-1	7/19/2021	$125,317.84	$125,317.84	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21080510843-1	8/5/2021	$85,238.54	$85,238.54	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21082611605-1	8/26/2021	$175,518.53	$175,518.53	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21090311887-1	9/3/2021	$104,970.44	$104,970.44	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21092912694-1	9/29/2021	$96,031.64	$96,031.64	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21102201473-1	10/22/2021	$190,140.46	$190,140.46	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21110802154-1	11/8/2021	$99,709.80	$99,709.80	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21111202302-1	11/12/2021	$92,803.14	$92,803.14	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21113002820-1	11/30/2021	$51,586.97	$51,586.97	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-21121003223-1	12/10/2021	$122,026.69	$122,026.69	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-22010403820-1	1/6/2022	$125,179.45	$125,179.45	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-22012104298-1	1/21/2022	$73,550.17	$73,550.17	$0.00	Davey Resource Group Inc. (V00000956693)
DO-1100-22020904890-1	2/9/2022	$71,281.58	$0.00	$71,281.58	Davey Resource Group Inc. (V00000956693)
			$2,231,795.44		

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Document	Date	Order Amount	Closed Amount	Outstanding	Vendor
DO-1100-21031806236-1	3/18/2021	$450,180.99	$450,180.99	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21040106725-1	4/1/2021	$266,462.02	$266,462.02	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21041607263-1	4/16/2021	$256,376.43	$256,376.43	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21050407866-1	5/4/2021	$278,011.93	$278,011.93	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21051908378-1	5/19/2021	$130,107.90	$130,107.90	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21061709283-1	6/17/2021	$244,235.56	$244,235.56	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21060208776-1	6/21/2021	$262,751.71	$262,751.71	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21071910205-1	7/21/2021	$268,733.91	$268,733.91	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21080410792-1	8/4/2021	$116,345.29	$116,345.29	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21082611593-1	8/31/2021	$183,724.79	$183,724.79	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21090211836-1	9/2/2021	$477,763.03	$477,763.03	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21092712613-1	9/27/2021	$188,556.46	$188,556.46	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21101200906-1	10/12/2021	$256,663.50	$256,663.50	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DOM-1100-MAX103068-1	10/13/2021	$212,854.49	$212,854.49	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21110802153-1	11/9/2021	$162,733.29	$162,733.29	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21111502388-1	11/16/2021	$25,783.44	$25,783.44	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21113002818-1	11/30/2021	$248,301.25	$248,301.25	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DOM-1100-MAX104186-1	12/1/2021	$64,855.00	$64,855.00	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21120903190-1	12/9/2021	$27,210.21	$27,210.21	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-22010403809-1	1/18/2022	$291,289.53	$291,289.53	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-22012404341-1	1/24/2022	$90,783.02	$90,783.02	$0.00	ASPLUNDH TREE EXPERT LLC (ASP7019530)
DO-1100-21031706200-1	3/17/2021	$84,707.75	$84,707.75	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21040506821-1	4/5/2021	$6,067.56	$6,067.56	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21041607289-1	4/16/2021	$91,352.44	$91,352.44	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21050707991-1	5/7/2021	$90,073.00	$90,073.00	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DOM-1100-MAX100026-1	5/14/2021	$270,771.87	$270,771.87	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21052008456-1	5/20/2021	$120,177.80	$120,177.80	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21060408875-1	6/4/2021	$145,675.50	$145,675.50	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21062309427-1	6/23/2021	$149,603.18	$149,603.18	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21071910225-1	7/19/2021	$316,830.20	$316,830.20	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21090311897-1	9/14/2021	$231,709.54	$231,709.54	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21092712615-2	10/6/2021	$229,827.37	$229,827.37	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21101401112-1	10/14/2021	$620,850.24	$618,523.84	$2,326.40	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21110802155-1	11/8/2021	$496,690.78	$496,690.78	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21113002824-1	11/30/2021	$228,228.74	$228,228.74	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DOM-1100-MAX104247-1	12/2/2021	$82,210.00	$82,210.00	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21121003232-1	12/10/2021	$472,863.11	$472,863.11	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-22011804165-2	1/19/2022	$685,073.97	$685,073.97	$0.00	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-22012404343-1	1/24/2022	$72,620.38	$0.00	$72,620.38	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-22021004916-1	2/10/2022	$207,712.78	$0.00	$207,712.78	DAVEY TREE SURGERY CO (DAV1450250)
DO-1100-21030405736-1	3/4/2021	$238,458.93	$238,458.93	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21031906277-1	3/31/2021	$104,701.30	$104,701.30	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21040606865-1	4/16/2021	$172,331.25	$172,331.25	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21041607293-1	4/16/2021	$179,030.06	$179,030.06	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21051208149-1	5/12/2021	$173,587.03	$173,587.03	$0.00	Wright Tree Service, Inc (WRI8303917)
DOM-1100-MAX100027-1	5/14/2021	$223,135.77	$223,135.77	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21052008462-1	5/20/2021	$178,762.55	$178,762.55	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21060408878-1	6/4/2021	$224,218.52	$224,218.52	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21062309431-1	6/24/2021	$114,375.75	$114,375.75	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21071910226-1	7/19/2021	$51,685.67	$51,685.67	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21080510847-1	8/5/2021	$187,210.46	$187,210.46	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21071910228-1	8/11/2021	$389,616.07	$389,616.07	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21082711652-1	8/27/2021	$86,951.76	$86,951.76	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21090711956-1	9/7/2021	$333,051.09	$333,051.09	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21092712621-1	9/27/2021	$91,639.19	$91,639.19	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21101200908-1	10/12/2021	$482,220.04	$481,515.42	$704.62	Wright Tree Service, Inc (WRI8303917)
DO-1100-21111002255-1	11/10/2021	$245,172.32	$245,172.32	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21111502389-1	11/15/2021	$154,921.46	$154,921.46	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21121303294-1	12/29/2021	$229,264.51	$229,264.51	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-22010703931-1	1/7/2022	$397,135.37	$397,135.37	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-22012404351-1	1/24/2022	$14,471.63	$14,471.63	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-22021004922-1	2/10/2022	$79,117.12	$0.00	$79,117.12	Wright Tree Service, Inc (WRI8303917)
			$13,095,346.51		

Asplundh	$4,503,724
Davey	$4,320,387
Wright	$4,271,236
	$13,095,347

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DO List For NA200000155					
Document	Date	Order Amount	Closed Amount	Outstanding	Vendor
DO-1100-21030405732-1	3/4/2021	$44,619.15	$44,619.15	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21031806246-1	3/18/2021	$22,761.00	$22,761.00	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21040606851-1	4/6/2021	$13,412.82	$13,412.82	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21041607292-1	4/16/2021	$23,196.19	$23,196.19	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21051208145-1	5/12/2021	$24,266.56	$24,266.56	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21052008460-1	5/20/2021	$26,316.60	$26,316.60	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21060408877-1	6/4/2021	$25,379.32	$25,379.32	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21062309430-1	6/23/2021	$26,335.83	$26,335.83	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21080510845-1	8/5/2021	$28,229.98	$28,229.98	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21082711651-1	8/27/2021	$24,461.94	$24,461.94	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21090711949-1	9/7/2021	$47,076.96	$47,076.96	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21100400450-1	10/4/2021	$2,332.80	$2,332.80	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21102201481-1	10/22/2021	$78,985.60	$78,985.60	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-21111002253-1	11/10/2021	$23,758.42	$23,758.42	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-22010703927-1	1/7/2022	$61,753.56	$61,753.56	$0.00	Wright Tree Service, Inc (WRI8303917)
DO-1100-22021004920-1	2/10/2022	$9,318.50	$0.00	$9,318.50	Wright Tree Service, Inc (WRI8303917)
			$472,886.73		

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 2-10: Referring to Appendix C, Page C-116, please provide documentation supporting the Annual Expense under New Software.

ANSWER: The outdated software system used in the Austin Energy call centers was replaced in FY 2022 with a new cloud-based software system, Genesys PureEngage Cloud Customer Care.

Attachment ICA RFI 2-10 details the known and measurable adjustment calculation for this new system.

Attachment ICA RFI 2-10: SD WP D-1_2_15 Genesys Call Center K&M

Prepared by: GJ/JG

Sponsored by: Jerry Galvan

Call Center Software New Contract

Fund	Fund Name	Department	Department Name	Unit	Unit Name	Activity	Actiity Name	Object Code	Object Name	Vendor	Vendor Name	Description	FY 2019	FY 2020	FY 2021
5010	Austin Energy Fund	1100	Austin Energy	8813	Call Center			6388	Maintenance-computer software	NOR8315773	ConvergeOne, Inc	Budgeted & Non-Budgeted Expense		$17,171.50	
5010	Austin Energy Fund	1100	Austin Energy	8813	Call Center	9034	Customer Service	6388	Maintenance-computer software	NOR8315773	ConvergeOne, Inc	Budgeted & Non-Budgeted Expense	528,157.26	514,814.00	502,164.70
5010	Austin Energy Fund	1100	Austin Energy	8813	Call Center	9304	Communication Exp - AE	6388	Maintenance-computer software	AVA7162460	AVAYA INC	Budgeted & Non-Budgeted Expense	471,749.79	0.00	
5010	Austin Energy Fund	1100	Austin Energy	8832	311 Technology and Support Operations			6388	Maintenance-computer software	NOR8315773	ConvergeOne, Inc	Budgeted & Non-Budgeted Expense		17,171.50	
5010	Austin Energy Fund	1100	Austin Energy	8832	311 Technology and Support Operations	4172	Exp Nonutlity Ops-311Call Cntr	6388	Maintenance-computer software	NOR8315773	ConvergeOne, Inc	Budgeted & Non-Budgeted Expense	528,157.26	0.00	
5010	Austin Energy Fund	1100	Austin Energy	8832	311 Technology and Support Operations	9304	Communication Exp - AE	6388	Maintenance-computer software	NOR8315773	ConvergeOne, Inc	Budgeted & Non-Budgeted Expense		514,813.95	502,164.70
													$1,528,064.31	$1,063,970.95	$1,004,329.40

FERC Acct			
903	$528,157.26	$531,985.50	$502,164.70
930	471,749.79	531,985.45	502,164.70
417	528,157.26	0.00	0.00
Total	$1,528,064.31	$1,063,970.95	$1,004,329.40

Genesys PureEngage Cloud Customer Care	Year 1	Year 2	Year 3	Year 4	Year 5
Software/Hardware/License/Subscription Services	$1,900,413	$1,900,413	$1,900,413	$1,900,413	$1,900,413
Non-recurring charges from Category 1 (One-time charge)	2,658				
Implementation/Deployment services (One-time charge)	762,895				
Total	$2,665,966	$1,900,413	$1,900,413	$1,900,413	$1,900,413

Annual Costs	
Software/Hardware/License/Subscription Services	$1,900,413
Non-recurring charges from Category 1 (amortized over contract term)	532
Implementation/Deployment services (amortized over contract term)	152,579
Total	$2,053,524

Known & Measurable Adjustment	FY 2021	Adjusted Total	K&M Adj
FERC 903	$502,165	$1,026,762	$524,597
FERC 930	502,165	1,026,762	524,597
Total	$1,004,329	$2,053,524	$1,049,195

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 2-12: Referring to Appendix C, Page c-247, please provide workpapers supporting the Normalized Base Revenue under Current Rates.

ANSWER: The amount of Normalized Base Revenue under Current Rates by customer class is formulaically linked to each of the relevant rate design worksheets (indicated as WP H-5.xx, where "xx" is 1 through 15). For example, the $298,139,951 for the Residential customer class is the sum of amounts in Columns C and F on Line numbers 14, 20, and 49 within WP H-5.1 (Appendix C, Page C-315).

Prepared by: GR

Sponsored by: Grant Rabon

ICA 2-13: Referring to Appendix C, Page c-247, please provide Base Revenue under Current Rates reflecting Fiscal Year 2022 billing determinants. The response should include all supporting workpapers.

ANSWER: Upon clarification with the ICA, this question refers to FY 2021 (rather than FY 2022) and the normalized base revenue amount. Please refer to the response in ICA RFI 2-12.

Prepared by: GR

Sponsored by: Grant Rabon