service, the IRC requires the Company to utilize ARAM in order to avoid a normalization violation. Amortizing protected excess ADIT using another method could result in a normalization violation.

Q35. HOW IS THE ANNUAL AMORTIZATION OF PROTECTED EXCESS ADIT CALCULATED?

A. The amortization of excess ADIT using ARAM does not begin until book depreciation exceeds tax depreciation, which is calculated for each vintage account record for the Company's plant in service. ARAM amortization is similar to the reversal of accumulated ADIT in that you continue to accumulate deferred income taxes until book depreciation exceeds tax depreciation, then you begin amortizing the deferred ADIT over the remaining book life of the underlying asset. Congress provided for the use of accelerated tax depreciation in order to provide an incentive for the investment in certain capital assets. The normalization rules preserve this incentive by, in part, (i) requiring that excess ADIT be amortized no faster than the rate at which the ADIT would have been reduced had the tax rate not changed and the excess not been created and (ii) requiring that this determination be made on an asset-by-asset basis (i.e., vintage account records) if the required property records are available. As a result, if the property records are available, ARAM requires the development of an average rate of amortization equal to (i) the amount of excess ADIT for each asset or asset class divided by (ii) the total amount of ADIT that has been provided on that same asset. Once the book depreciation exceeds tax depreciation, the average rate of amortization is calculated and applied to the annual ADIT reversal to calculate the amortization of the excess ADIT on an annual basis.

Q36. DOES THE TOTAL AMORTIZATION OF PROTECTED EXCESS ADIT CHANGE ANNUALLY?

A. Yes. Since the calculation of the amortization of protected excess ADIT does not begin until book depreciation exceeds tax depreciation for each vintage account, the Company's total amortization will change annually as ADIT begins to reverse for each asset and vintage.

Q37. HOW DID THE COMPANY CALCULATE THE AMORTIZATION OF THE EXCESS ADIT FROM THE TCJA IN THIS FILING?

A. The actual amortization of protected excess ADIT from the TCJA cannot be finalized for any year until both the book depreciation and federal income tax depreciation are finalized, which occurs when the federal income tax return is filed for that year. The amortization of the protected excess ADIT from the TCJA that is included in income tax expense in this filing is the excess activity included in the Company's most recently filed 2023 tax return and can be seen in Schedule G-09, line 3, column (d).

Q38. HOW DID THE COMPANY CALCULATE THE AMORTIZATION OF UNPROTECTED EXCESS ADIT FROM THE TCJA IN THIS FILING?

A. The Company is not requesting the amortization of any additional unprotected excess ADIT resulting from the TCJA in this rate filing.

Q39. WHY IS THE COMPANY NOT REQUESTING ANY AMORTIZATION OF ADDITIONAL UNPROTECTED EXCESS ADIT RESULTING FROM THE TCJA IN THIS FILING?

A. In compliance with the final order in Docket No. 52195, the Company is already returning the TCJA unprotected excess ADIT accrued prior to January 1, 2018, and the excess ADIT resulting from the TCJA that accrued from January 1, 2018 through the period in which the rates established in Docket No. 52195 were put into effect (i.e., the "stub period") via a rate rider. The Company recommends continuing the amortization of this excess ADIT through the rider until it is fully returned to customers.

Q40. ARE THERE ADDITIONAL EXCESS ADIT BALANCES THAT ARE INCLUDED IN THIS FILING?

A. Yes. Although there are no new excess ADIT issues since Docket No. 52195, the Company continues to amortize the excess ADIT from federal income tax rate changes in the 1980s. The Company also has excess state ADIT resulting from the normalization of state income taxes and excess state ADIT that relate to prior years phase in of state rate reductions. These amounts can be found in the work papers to Schedule G-7.9(a).

VII. Federal Income Taxes

Q41. HOW HAVE FEDERAL INCOME TAXES INCLUDED IN COST OF SERVICE BEEN CALCULATED?

A. Federal income taxes have been calculated using the return method for the Adjusted Test Year, as required by the Instructions and Schedules to the RFP.

Q42. WHAT IS THE RETURN METHOD?

A. The calculation of federal income taxes provided on Schedule G-7.8 is commonly referred to as the return method because it calculates federal income taxes using an after-tax return as the starting point. Under this method, equity return, or total return less interest, is adjusted for items for which there is no tax deduction to offset amounts recovered through revenues — such as book amortization of Allowance for Equity Funds Used During Construction, other flow-through differences, permanent differences, ITC amortization, and the amortization of excess ADIT. The return method calculates federal income tax expense in total, with no segregation between current and deferred federal income taxes. The return method tax calculation provided on Schedule G-7.8 reflects a stand-alone approach to calculating federal income taxes.

Q43. WHAT IS MEANT BY A STAND-ALONE APPROACH?

A. The stand-alone methodology calculates federal income taxes on utility revenues and expenses that are included in the utility's revenue requirement. This approach appropriately allocates federal income taxes between customers and shareholders using the benefits and -burdens criteria outlined by FERC Opinion No. 173. Under this methodology, federal income tax expense relates to, and results from, the provision of utility service to customers. Additionally, the stand-alone federal income tax calculation includes an adjustment to synchronize interest. Synchronized interest represents the portion of return that is deductible for tax purposes and is calculated by multiplying the weighted cost of debt by rate base. Use of synchronized interest in the tax calculation effectively synchronizes the calculation of federal income tax expense with rate base and rate of return.

Synchronized interest may be more or less than the actual interest deducted on the tax return.

Q44. WHY IS THE STAND-ALONE APPROACH THE PROPER METHODOLOGY TO USE IN CALCULATING FEDERAL INCOME TAXES FOR RATEMAKING PURPOSES?

A. The stand-alone approach, required by section 36.060 of the Public Utility Regulatory Act ("PURA"), includes in cost of service only federal income taxes that result from the provision of utility service to customers. Federal income taxes requested by the Company are based on revenues and expenses included in the cost-of-service calculation. There are no additions to or reductions from tax expense resulting from revenues or expenses not included in the Company's request. It is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers.

Said another way, income taxes have no independent existence of their own. They are based on revenues and expenses. Once the Commission decides on the appropriate revenues and expenses that are necessary for the provision of electric service, the related income taxes can be determined.

Q45. WHAT IS THE AMOUNT OF FEDERAL INCOME TAX EXPENSE THE COMPANY IS REQUESTING TO BE INCLUDED IN RATES?

A. The Company is requesting the amount of federal income tax expense that is included in overall cost of service in Schedule A as calculated on Schedule G-7.8.

Q46. HAS THE COMPANY COMPUTED FEDERAL INCOME TAXES IN ACCORDANCE WITH SECTIONS 36.059 AND 36.060 OF PURA?

A. Yes. PURA sections 36.059 and 36.060 address the treatment of certain tax benefits, including ITC and consolidated tax savings. PURA sections 36.059(b) and 36.060(c) specifically require a utility that retains ITC to deduct it from the rate base to which the credit applied, to the extent allowed by the IRC. The post 1970 portion of unamortized ITC is not included as a reduction of rate base because the Company is an Option 2 company for ITC purposes. Under IRC Section 46(f), an Option 2 election requires that the post 1970 ITC be returned to customers as a reduction of cost of service, rather than as a reduction of rate base.

Additionally, PURA section 36.060(b) requires that income taxes related to intercompany profits on affiliated purchases be applied to reduce the cost of the property or service purchased. As a result of its merger with Sun Jupiter Holdings, LLC ("Sun Jupiter"), the Company did have affiliates for the Test Year ended September 30, 2024, and will participate in a consolidated tax return for 2024, but the Company has no intercompany profits on affiliated purchases for the Test Year. No benefits generated by EPE have been distributed to its affiliates during the Test Year. As a result, tax expense included in this filing has been calculated in accordance with PURA section 36.060(b).

Further, PURA section 36.060(a) requires that income tax expense included in cost of service reflect only expenses and investments included in cost of service and rate base. Accordingly, the Company has calculated its income tax expense on a stand-alone basis. The Company's income tax amounts included in cost of service are consistent with this provision.

VIII. State Income Taxes

Q47. WHAT IS THE AMOUNT OF STATE INCOME TAX EXPENSE THE COMPANY IS REQUESTING BE INCLUDED IN COST OF SERVICE?

A. The Company is requesting the amount of state income tax expense in cost of service reflected on Schedules G-7.6 and G-7.8.

Q48. WHICH ACCOUNTING METHOD HAS EPE USED TO DETERMINE STATE INCOME TAX EXPENSE IN THIS CASE?

A. Consistent with the settlement agreement that was approved by the Commission Final Order in the Company's 2015 base rate case, PUCT Docket No. 44941, the Company has used the normalization method to determine the state income tax expense included in cost of service.

Q49. IN WHAT JURISDICTIONS DOES THE COMPANY FILE INCOME TAX RETURNS?

A. The Company files state income tax returns in Arizona, New Mexico and Texas jurisdictions.

Q50. IS THE INCOME TAX EXPENSE FROM EACH OF THESE JURISDICTIONS INCLUDED IN THIS FILING?

A. Yes. EPE includes state tax expense from each of the jurisdictions in its cost of service and the associated state ADIT in rate base.

Q51. WHY IS EPE INCLUDING STATE INCOME TAXES FOR JURISDICTIONS OUTSIDE OF TEXAS?

A. EPE is including state income taxes for each of its taxing jurisdictions in which it has property or payroll (i.e., employees). Property and payroll generally cause nexus for state income tax purposes, which obligates EPE to pay income taxes in those jurisdictions. EPE's property and payroll in each of these jurisdictions are integral to the Company being able to serve its customers in Texas. Therefore, state income taxes for all three jurisdictions are included in this filing.

IX. Income Tax Schedules

Q52. PLEASE DESCRIBE SCHEDULE G-7.1, RECONCILIATION OF TEST YEARBOOK NET INCOME TO TAXABLE NET INCOME.

A. Schedule G-7.1 is the reconciliation of book net income to taxable net income on a total company basis for the Test Year and for the most recently filed federal income tax return. Since Schedule G-7.1 is a comparison to the most recently filed federal income tax return, amounts include both operating and nonoperating activities. Schedule G-7.1 contains explanations of all items in the reconciliation for both the Test Year and the tax return.

Q53. PLEASE DESCRIBE SCHEDULE G-7.1(a), RECONCILIATION OF TIMING DIFFERENCES.

A. This schedule includes a listing of timing differences and other items that produce federal income tax for the Test Year at a tax rate different than the statutory 21% federal tax rate, with explanations describing each item.

Q54. PLEASE DESCRIBE SCHEDULE G-7.2, PLANT ADJUSTMENTS.

A. This schedule provides the tax basis, tax in-service date, tax depreciation methods, and tax depreciation in the Test Year and projected for the two subsequent years, and the amount of Accumulated Deferred Federal Income Taxes ("ADFIT") as of the Test Year-end for any new generating unit requested (purchased or constructed since the Company's last rate case) and any requested plant adjustments to the Test Year. The Company has added a new generating unit since filing its last base rate case. Newman Unit 6 was added to Plant in Service on December 27, 2023. Please see post-test year adjustments in G-7.2.

Q55. PLEASE DESCRIBE SCHEDULE G-7.3, CONSOLIDATED TAXES.

A. This schedule is not applicable. This schedule provides descriptions of any tax effect on the filing utility because of its inclusion within a consolidated income tax return for the most recent tax year. EPE did file as part of a consolidated group in its most recently filed tax return for the calendar year ended December 31, 2023. However, the taxes contained in this filing are presented on a stand-alone basis and contain no consolidated effects.

Q56. PLEASE DESCRIBE SCHEDULE G-7.3(a), CONSOLIDATION BENEFITS.

A. This schedule is not applicable. The Company did file as part of a consolidated group on its most recently filed income tax return. However, the taxes contained in this filing are presented on a stand-alone basis and contain no consolidated effects.

Q57. PLEASE DESCRIBE SCHEDULE G-7.3(b), CONSOLIDATION/INTER-CORPORATE TAX ALLOCATION.

A. This schedule is not applicable to the Company. The Company did file as part of a consolidated group on its most recently filed income tax return. However, the taxes contained in this filing are presented on a stand-alone basis and contain no consolidated effects.

Q58. PLEASE DESCRIBE SCHEDULE G-7.4, ADFIT.

A. This schedule shows the balance sheet amount of ADIT, which includes both federal and state, for each of the twelve months of the Test Year; at the end of the Test Year; and the additions and reductions during the Test Year as well as the requested adjustments to the balances. Each item that gives rise to ADIT is shown separately on this schedule.

Q59. PLEASE DESCRIBE SCHEDULE G-7.4(a), ADFIT-DESCRIPTION OF TIMING DIFFERENCES.

A. This schedule includes a description of the nature and remaining life, where applicable, of each timing difference listed in Schedule G-7.4.

Q60. PLEASE DESCRIBE SCHEDULE G-7.4(b), ADJUSTMENTS TO ADFIT.

A. This schedule shows the details of the adjustments to the balance sheet ADIT accounts. The reasons for these adjustments are included as well as the supporting calculations, if any.

Q61. DOES THIS SCHEDULE REFLECT THE IMPACTS OF BONUS DEPRECIATION?

A. Yes. The Company has claimed bonus depreciation as permitted by the IRC. Depending on the year certain capital assets were placed in service, the additions were eligible for the 50% or 100% bonus depreciation deduction based on the applicable rate enacted for that year. This effectively means that, for income tax purposes—in addition to tax depreciation computed using the Modified Accelerated Cost Recovery System ("MACRS")—the Company claimed an additional 50% or 100% of the eligible tax basis as a tax depreciation deduction in the first year. As a result, EPE's Test Year end ADIT related to these book-tax depreciation temporary differences reflect the future tax liability associated with these accelerated deductions.

Q62. DID THE COMPANY REMOVE TEST YEAR END ADIT FOR AMOUNTS RELATED TO UNCERTAIN TAX POSITIONS REQUIRED TO BE IDENTIFIED AND ACCOUNTED FOR BY FINANCIAL ACCOUNTING STANDARDS BOARD INTERPRETATION 48 ("FIN 48")?

A. No reductions were made to Test Year end ADIT in rate base for FIN 48 reserves.

Q63. PLEASE DESCRIBE SCHEDULE G-7.4(c), ADFIT AND ITC – PLANT ADJUSTMENTS AND ALLOCATIONS.

A. This schedule provides the accumulated deferred income tax balances at Test Year end related to additions for new generating plant in service since the Company's last filing and any plant adjustments to the Test Year end requested by the Company and the supporting calculations. The Company has added a new generating unit since filing its last base rate case. Newman Unit 6 was put in Service on December 27, 2023.

Q64. PLEASE DESCRIBE SCHEDULE G-7.4(d), ADFIT-RATE CASE EXPENSE.

A. This schedule is not applicable. The Company did not have any ADIT associated with rate case expense reflected on the books on September 30, 2024.

Q65. PLEASE DESCRIBE SCHEDULE G-7.5, ANALYSIS OF ITCS.

A. This schedule presents the analysis of the ITC adjustment for Deferred Investment Tax Credit ("DITC") to be included in cost of service. The Company's election under Section 46(f)(2) of the IRC does not permit amortization of ITC to reduce income tax expense in cost of service at a rate more rapidly than ratably — no faster than over the book life of the assets that generated the ITC. The stripped book depreciation rate requested is derived from the proposed depreciation rate calculations supported by EPE witness John Spanos. This rate represents the life or investment portion of the depreciation rate without regard to amounts for cost of removal or salvage. The stripped depreciation rate is multiplied by the ITC amortization base to calculate the annual amount of DITC amortization included in cost of service. The stripped depreciation rate is used in this computation to avoid a potential normalization violation that could result if the ITCs were amortized in cost of service at a rate more rapid than ratably. Workpaper G-7.5 shows the calculation of the Test Year ITC. For each class of assets generating the ITC, the Company applied the stripped depreciation rate to the ITC amortization base to arrive at the ITC amortization used to reduce income tax expense.

Q66. PLEASE DESCRIBE SCHEDULE G-7.5(a), UTILIZED.

A. This schedule shows the ITC utilized (claimed on the income tax return) each year.

Q67. PLEASE DESCRIBE SCHEDULE G-7.5(b), GENERATED BUT NOT UTILIZED.

A. This schedule presents the ITC generated but not utilized at the Test Year end September 30, 2024. This schedule is not applicable to the Company. All investment credits that were generated prior to September 30, 2024, have been utilized by EPE.

Q68. PLEASE DESCRIBE SCHEDULE G-7.5(c), UTILIZED – STAND-ALONE BASIS.

A. This schedule is not applicable to the Company. All investment credits have been utilized by EPE on a stand-alone basis.

Q69. PLEASE DESCRIBE SCHEDULE G-7.5(d), ITC ELECTION.

A. This schedule describes the tax elections made by EPE with regard to ITC.

Q70. PLEASE DESCRIBE SCHEDULE G-7.5(e), FERC ACCOUNT 255 BALANCE.

A. This schedule shows the account balance for FERC Account No. 255 – Accumulated Deferred Investment Tax Credits as of September 30, 2024.

Q71. PLEASE DESCRIBE SCHEDULE G-7.6, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT – TAX METHOD 2.

A. This schedule calculates federal and state income tax expense for the Test Year using Tax Method 2. This method of calculating federal and state income tax expense determines the current and deferred components of tax expense separately. The components of tax expense shown on this schedule include taxes currently payable, deferred taxes, and DITC amortization. The total income tax expense amount calculated by Tax Method 2 is equal to the amount of tax expense computed under the return method (see Schedule G-7.8).

Q72. PLEASE DESCRIBE SCHEDULE G-7.6(a), ANALYSIS OF DEFERRED FIT.

A. This schedule is an analysis of each deferred tax item that makes up the federal deferred tax expense in Schedule G-7.6.

Q73. PLEASE DESCRIBE SCHEDULE G-7.7, ANALYSIS OF ADDITIONAL DEPRECIATION REQUESTED.

A. This schedule provides the detailed support for the requested adjustment to return for additional depreciation. This schedule summarizes the major components related to flowthrough book depreciation for which there is no tax benefit. Workpaper G-7.7 provides the detailed calculations for this schedule.

Q74. PLEASE DESCRIBE SCHEDULE G-7.8, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT – TAX METHOD 1.

A. This schedule calculates federal and state income tax expense for the Test Year using Tax Method 1, the return method. The income tax expense calculated by Tax Method 1 is equal to the amount of tax expense computed by Tax Method 2 (see Schedule G-7.6).

Q75. PLEASE DESCRIBE SCHEDULE G-7.9, AMORTIZATION OF PROTECTED AND UNPROTECTED EXCESS DEFERRED TAXES.

A. This schedule summarizes the amortization of protected and unprotected excess deferred federal income tax and the amortization methodology utilized.

Q76. PLEASE DESCRIBE SCHEDULE G-7.10, EFFECTS OF ACCOUNTING ORDER DEFERRALS.

A. This schedule is not applicable. The Company does not have any ADIT or federal income tax as of September 30, 2024, related to accounting order deferrals.

Q77. PLEASE DESCRIBE SCHEDULE G-7.11, EFFECTS OF POST TEST YEAR ADJUSTMENT.

A. This schedule shows the effects on FIT and ADFIT for the Company's requested posttest year adjustments to Plant.

Q78. PLEASE DESCRIBE SCHEDULE G-7.12, EFFECTS OF RATE MODERATION PLAN.

A. The Company does not have an existing rate moderation plan and is not requesting a rate moderation plan.

Q79. PLEASE DESCRIBE SCHEDULE G-7.12(a), TREATMENT OF FIT AND ADFIT IN RATE MODERATION PLAN.

A. The Company does not have an existing rate moderation plan and all federal income tax and ADIT from previous rate moderation plans have been fully amortized.

Q80. PLEASE DESCRIBE SCHEDULE G-7.13, LIST OF FIT TESTIMONY.

A. This schedule lists all witnesses that are filing testimony in this case that support the Company's federal income tax and ADIT requests. The most recent tax return filed (for the calendar year ended December 31, 2023) is included as part of the confidential workpapers for this schedule.

Q81. PLEASE DESCRIBE SCHEDULE G-7.13(a), HISTORY OF TAX NORMALIZATION.

A. This schedule details the history of tax normalization for the Company and also provides details of the first year for each timing difference and the first year normalized.

Q82. PLEASE DESCRIBE SCHEDULE G-7.13(b), TAX ELECTIONS.

A. Tax elections made by the Company since the Test Year end reflected in the last base rate filing, Docket No. 52195, are detailed in this schedule.

Q83. PLEASE DESCRIBE THE CHANGES IN ACCOUNTING FOR DEFERRED TAXES SHOWN ON SCHEDULE G-7.13(c).

A. There have been no changes in accounting for federal deferred income taxes.

Q84. PLEASE DESCRIBE SCHEDULE G-7.13(d), IRS AUDIT STATUS.

A. This schedule explains the Company's current federal income tax audit status. The Company is not currently under audit.

Q85. SCHEDULE G-7.13(e) RELATES TO PRIVATE LETTER RULINGS SINCE THE LAST RATE FILING. HAVE THERE BEEN ANY PRIVATE LETTER RULINGS

RECEIVED SINCE THE LAST RATE FILING THAT AFFECT THE FEDERAL INCOME TAX OF THE COMPANY?

A. There have been no private letter rulings received by the Company since the last rate filing. The Company did file three requests for private letter rulings related to the funding of our three decommissioning trust funds. The requests were filed on July 28, 2023. We have yet to receive a response.

Q86. PLEASE DESCRIBE SCHEDULE G-7.13(f), METHOD OF ACCOUNTING FOR ADFIT RELATED TO NOL CARRYFORWARD.

A. This schedule describes the method of accounting for the Company's NOL Carryforwards, and the balances included in ADIT at the Test Year end September 30, 2024.

X. Taxes Other Than Income

Q87. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I first discuss the Company's property taxes. I then discuss the remaining taxes other than income that the Company incurs.

A. Property Taxes

Q88. WHAT WAS THE TOTAL AMOUNT OF PROPERTY TAXES DURING THE TEST YEAR?

A. The total amount of property taxes for the Company in the Test Year is shown on Schedule G-9.

Q89. WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S PROPERTY TAXES?

A. The total amount of requested property taxes can be found on Schedule G-9.

Q90. HOW ARE THE PROPERTY TAXES FOR THE COMPANY DETERMINED?

A. The property taxes charged to the Company are the amounts imposed by taxing authorities to which the Company is subject. Property taxes are capitalized to construction work in process for assets currently under construction based on an assessed value or are expensed for assets in electric plant in service.

Q91. PLEASE DESCRIBE THE VARIOUS TAXING AUTHORITIES THAT LEVY PROPERTY TAXES AGAINST THE COMPANY'S PROPERTY.

A. The Company is subject to property taxation by many different taxing jurisdictions. These taxing jurisdictions include, but are not limited to, counties, cities, independent school districts, fire districts, and industrial districts. Also, various taxing jurisdictions overlap, and, for example, a single piece of utility property may be the basis for property tax levied by as many as six or more jurisdictions.

Q92. HOW ARE THE PROPERTY TAX AMOUNTS IMPOSED BY THE TAXING JURISDICTIONS DETERMINED?

A. Property tax is typically assessed against the appraised or taxable value of the Company's property located within the jurisdiction of a taxing authority. Generally, the property tax appraisal process is a two-step process for a regulated utility. The first step is to establish a market value for all of the utility's property, collectively. This is referred to as a "unit" valuation. The second step is to allocate that market value of the unit to the taxing jurisdictions in which the utility owns taxable property.

Once the taxable value for a tax jurisdiction is determined and final, the jurisdiction calculates and sends a bill to the taxpayer. The billed amount is determined by multiplying the jurisdiction's tax rate by the taxable value of EPE's property in that jurisdiction.

Q93. PLEASE DESCRIBE SCHEDULE G-9.1, AD VALOREM TAXES AND PLANT BALANCES.

A. This schedule shows the amount of ad valorem taxes assessed, penalties paid, and discounts taken for the three calendar years shown on Schedule G-9, as well as the net plant balances at the beginning of each of those years.

Q94. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST YEAR PROPERTY TAX AMOUNT?

A. Yes. The Company has made pro forma adjustments to its Test Year property tax amounts to reflect an effective rate of tax assessed on adjusted net plant in service balances on September 30, 2024. The adjustment is included in Workpaper A-3, Adjustment No. 15.

B. Revenue-Related Taxes

Q95. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I sponsor the Company's revenue-related taxes. By "revenue-related taxes", I mean the Company's directly incurred local franchise fees; sales, use and gross receipts taxes; and other miscellaneous taxes plus state regulatory assessments.

Q96. WHAT WAS THE TOTAL AMOUNT OF REVENUE-RELATED TAXES DURING THE TEST YEAR?

A. The total amount of revenue-related taxes for the Company in the Test Year is shown on Schedule G-9.

Q97. WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S REVENUE-RELATED TAXES?

A. The total amount of requested revenue-related taxes can be found on Schedule G-9.

Q98. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST-YEAR REVENUE-RELATED TAXES?

A. Yes. Adjustments were made to revenue-related taxes that were necessary to reflect adjustments to the underlying amounts in cost of service. The adjustments were calculated based on an effective tax rate determined by dividing the applicable taxes expensed by taxable Company revenues. These effective tax rates were adjusted for the effective uncollectible expenses rate and then applied to requested revenues to determine the amount of taxes included in the requested cost of service. These adjustments are reflected on Schedule G-9 and are calculated in Workpaper A-3, Adjustment No. 17.

C. Payroll Taxes

Q99. WHAT WAS THE TOTAL AMOUNT OF PAYROLL TAXES DURING THE TEST YEAR?

A. The total amount of payroll taxes for the Company in the Test Year is shown on Schedule G-9.

Q100. WHAT IS THE NET REQUESTED RECOVERY AMOUNT FOR THE COMPANY'S PAYROLL TAXES?

A. The total amount of requested payroll taxes can be found on Schedule G-9.

Q101. HAS THE COMPANY MADE ANY PRO FORMA ADJUSTMENTS TO ITS TEST YEAR PAYROLL TAXES?

A. Yes. Payroll taxes were calculated based on the adjusted salary and wage levels as discussed in the testimony of EPE witness Steven Sierra. These adjustments are reflected on Schedule G-9 and are calculated in Workpaper A-3, Adjustment No. 16.

Q102. ARE THESE EXPENSES NECESSARY AND REASONABLE?

A. Yes. All of the above-described taxes are necessary because they are required by law in order to allow the Company to operate in its applicable jurisdictions. The amounts are reasonable because the taxes are imposed by law and calculated in accordance with applicable law and reflect the requested rate base and cost of service.

XI. Conclusion

Q103. PLEASE STATE YOUR CONCLUSIONS.

A. The Company's per books and Test Year federal and state income tax amounts found in the G-7 schedules and included in the Company's requested cost of service and rate base are reasonable and necessary and calculated in accordance with PURA and the Commission's rules. Additionally, the amounts of the Company's taxes other than income found in the G9 schedules and included in the Company's requested cost of service are also reasonable and necessary and calculated in accordance with applicable law.

Q104. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY T. HENDERSON

Schedule	Description	Sponsorship
G-7.1	RECONCILIATION OF TY BOOK NET INCOME TO TAXABLE NET INCOME	Sponsor
G-7.1a	RECONCILIATION OF TIMING DIFFERENCES	Sponsor
G-7.2	PLANT ADJUSTMENTS	Sponsor
G-7.3	CONSOLIDATED TAXES	Sponsor
G-7.3a	CONSOLIDATION BENEFITS	Sponsor
G-7.3b	CONSOLIDATION / INTER-CORPORATE TAX ALLOCATION	Sponsor
G-7.4	ADFIT	Sponsor
G-7.4a	ADFIT - DESCRIPTION OF TIMING DIFFERENCES	Sponsor
G-7.4b	ADJUSTMENTS TO ADFIT	Sponsor
G-7.4c	ADFIT AND ITC - PLANT ADJUSTMENTS & ALLOCATIONS	Sponsor
G-7.4d	ADFIT - RATE CASE EXPENSE	Sponsor
G-7.5	ANALYSIS OF INVESTMENT TAX CREDITS	Sponsor
G-7.5a	UTILIZED	Sponsor
G-7.5b	GENERATED BUT NOT UTILIZED	Sponsor
G-7.5c	UTILIZED - STAND ALONE BASIS	Sponsor
G-7.5d	INVESTMENT TAX CREDIT ELECTION	Sponsor
G-7.5e	FERC ACCOUNT 255 BALANCE	Sponsor
G-7.6	ANALYSIS OF TYE FIT & REQUESTED FIT - TAX METHOD 2	Sponsor
G-7.6a	ANALYSIS OF DEFERRED FIT	Sponsor
G-7.7	ANALYSIS OF ADDITIONAL DEPRECIATION REQUESTED	Sponsor
G-7.8	ANALYSIS OF TYE FIT & REQUESTED FIT - TAX METHOD 1	Sponsor
G-7.9	ANALYSIS OF EXCESS DEFERRED TAXES	Sponsor
G-7.9a	ANALYSIS OF EXCESS DEFERRED TAXES BY TIMING DIFFERENCE	Sponsor

SCHEDULES SPONSORED BY T. HENDERSON

G-7.9b	RECONCILIATION OF EXCESS	Sponsor
G-7.9c	ANALYSIS OF RESERVE ACCOUNTING FOR EXCESS DEFERRED TAXES	Sponsor
G-7.10	EFFECTS OF ACCOUNTING ORDER DEFERRALS	Sponsor
G-7.11	EFFECTS OF POST TEST YEAR ADJUSTMENT	Sponsor
G-7.12	EFFECTS OF RATE MODERATION PLAN	Sponsor
G-7.12a	TREATMENT OF FIT AND ADFIT IN RATE MODERATION PLAN	Sponsor
G-7.13	LIST OF FIT TESTIMONY	Sponsor
G-7.13a	HISTORY OF TAX NORMALIZATION	Sponsor
G-7.13b	TAX ELECTIONS	Sponsor
G-7.13c	CHANGES IN ACCOUNTING FOR DEFERRED FIT	Sponsor
G-7.13d	IRS AUDIT STATUS	Sponsor
G-7.13e	PRIVATE LETTER RULINGS	Sponsor
G-7.13f	METHOD OF ACCOUNTING FOR ADFIT RELATED TO NOL CARRYFORWARD	Sponsor
G-9	TAXES OTHER THAN INCOME TAXES	Sponsor
G-9.1	AD VALOREM TAXES & PLANT BALANCES	Sponsor

TAX SHARING AGREEMENT

This Tax Sharing Agreement (this "Agreement"), dated effective as of July 29, 2020, is made and entered into as of July 29, 2020, by and among Sun Jupiter Topco LLC, a Delaware Limited Liability Company ("Parent"), Sun Jupiter Parent LLC, a Delaware Limited Liability Company, Sun Jupiter Holdings LLC, a Delaware Limited Liability Company and El Paso Electric Company, a Texas Corporation (each party, a "Sun Jupiter Affiliate" and collectively, the "Sun Jupiter Affiliates").

RECITALS

WHEREAS, all of the Sun Jupiter Affiliates are members of an affiliated group of corporations within the meaning of section 1504(a) of the Internal Revenue Code of 1986, as amended (the "Code"), of which Parent is the common parent (the "Sun Jupiter Group");

WHEREAS, some or all of the Sun Jupiter Affiliates may be included in a group of entities headed by Parent or another Sun Jupiter Affiliate that is entitled to file Tax Returns (as defined below) with respect to state or local Taxes (as defined below) on a consolidated, combined, or unitary basis (a "State Group"); and

WHEREAS, the Sun Jupiter Affiliates desire to set forth their agreement regarding the allocation of Taxes and the rights and responsibilities of the Sun Jupiter Affiliates with respect to Tax Returns, Tax Contests (as defined below) and other related Tax matters.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual obligations and undertakings contained herein, the Sun Jupiter Affiliates agree as follows:

1. DEFINITIONS.

1.1 Previously Defined Terms. Each term defined in the first paragraph of this Agreement and the Recitals shall have the meaning specified above whenever used in this Agreement.

1.2 Other Definitions. When used in this Agreement, the following terms shall have the following respective definitions:

"Combined Tax Return" shall have the meaning specified in Section 3.2 of this Agreement.

"Consolidated Tax Return" shall have the meaning specified in Section 3.1 of this Agreement.

"Deconsolidation Event" shall mean any event or transaction that causes one or more Sun Jupiter Affiliates to no longer be eligible to file a Consolidated Tax Return or a Combined Tax Return.

"Estimated Payment Date" shall mean each of the due dates prescribed in section 6655(c) of the Code.

"Estimated Tax Sharing Amount" shall have the meaning specified in Section 4.4(a) of this Agreement.

"Federal Income Tax Liability" shall mean, for each taxable period, the Tax liability imposed under Subtitle A of the Code (including the Taxes imposed by section 11 of the Code), and any interest, additions to Tax or penalties applicable or related thereto.

"Final Determination" shall mean the final resolution of any Tax for a taxable period that, under applicable law, is not subject to further appeal, review or modification through proceedings or otherwise.

"Independent Tax Return" shall have the meaning specified in Sections 3.3 and 3.4 of this Agreement.

"Item" shall mean any item of income, gain, deduction, Loss or credit received, earned, paid or incurred by a Sun Jupiter Affiliate.

"Loss" shall mean the excess for a taxable period of a Sun Jupiter Affiliate's deductions for federal or state income Tax purposes over its income for such purposes computed in the manner used to compute its Separate Return Tax Liability (or its State or Local Tax Sharing Amount in the applicable state or local taxing jurisdiction).

"Payment Account" shall have the meaning specified in Section 8 of this Agreement.

"Payment Sections" shall have the meaning specified in Section 8 of this Agreement.

"Pre-Deconsolidation Period" shall mean any taxable period beginning on or before the date of a Deconsolidation Event.

"Separate Return Tax Liability" shall mean, for each taxable period, a Sun Jupiter Consolidated Member's allocable share of the Federal Income Tax Liability of the Sun Jupiter Group determined in accordance with the methodology set forth in sections 1.1552-1(a)(1) and 1.1502-33(d)(3) of the Treasury regulations.

"State Group Head" shall mean Parent or any other Sun Jupiter Affiliate that is the parent of a State Group.

"State or Local Tax Sharing Amount" shall have the meaning specified in Section 5.2 of this Agreement.

"Sun Jupiter Combined Member" shall mean, with respect to any State Group, a Sun Jupiter Affiliate that is included in such State Group and is not a disregarded entity with respect to such State Group.

"Sun Jupiter Consolidated Member" shall mean a Sun Jupiter Affiliate that is a member (within the meaning of section 1.1502-1(b) of the Treasury regulations) of the Sun Jupiter Group.

"Tax" shall mean any federal, state or local tax, impost, rate, charge, fee, duty, levy, or other assessment or charge of any kind whatsoever, together with any related interest, penalties or other additions to tax, imposed by a taxing authority.

"Tax Asset" shall mean any Item that has accrued for Tax purposes, but has not been realized during the taxable period in which it has accrued, and that could reduce a Tax in another taxable period, including a net operating loss, net capital loss, investment tax credit, foreign tax credit, charitable deduction or any other Tax credits.

"Tax Contest" shall have the meaning specified in Section 4.6 of this Agreement.

"Tax Return" shall mean any return, report, certificate, election, form or similar statement or document (including, any related or supporting information or schedule attached thereto and any information return, amended Tax Return, claim for refund or declaration of estimated Tax) supplied to, or filed with, or required to be supplied to, or filed with, a taxing authority in connection with the determination, assessment or collection of any Tax or the administration of any laws, regulations or administrative requirements relating to any Tax.

"Tax Sharing Amount" shall have the meaning specified in Section 4.1 of this Agreement.

2. AGENCY.

Each Sun Jupiter Affiliate hereby designates Parent as its sole and exclusive agent and attorney-in-fact in respect to all matters pertaining to (a) the payment of such Taxes as are imposed in the United States of America and calculated on a consolidated, combined or unitary basis, and (b) compliance with all laws applicable to such Taxes, and hereby authorizes Parent to take on its behalf such action (including execution of documents) as Parent in its sole discretion, may deem appropriate in any and all matters (including audits and other proceedings) relating to any Tax Return described in Sections 3.1 or 3.2 of this Agreement.

3. TAX RETURN PREPARATION.

3.1 Consolidated Federal Tax Returns. Parent shall have exclusive control over all matters relating to the preparation and filing of any consolidated federal income Tax Return of the Sun Jupiter Group (a "Consolidated Tax Return").

3.2 Consolidated, Combined or Unitary State or Local Tax Returns. Parent shall have exclusive control over all matters relating to the preparation and filing of any state or local Tax Return filed on a consolidated, combined, or unitary basis (including, without limitation, any Tax based in whole or in part by net income or gross income or any franchise, gross receipt, net capital or other similar Taxes) with respect to any State Group (a "Combined Tax Return").

3.3 Separately Filed State or Local Income Tax Returns. The applicable Sun Jupiter Affiliate shall have exclusive control over all matters relating to the preparation and filing of any of its state or local income Tax Returns other than any Combined Tax Returns (together with Tax Returns described in Section 3.4 of this Agreement, an "Independent Tax Return").

3.4 Non-Income State or Local Tax Returns. The applicable Sun Jupiter Affiliate shall have exclusive control over all matters relating to the preparation and filing of any of its non-income state or local Tax Returns (together with Tax Returns described in Section 3.3 of this Agreement, an "Independent Tax Return") .

4. ALLOCATION, PAYMENT AND REFUND OF FEDERAL INCOME TAXES.

4.1 Allocation of Federal Income Taxes. For each taxable period, each Sun Jupiter Consolidated Member shall be liable for and pay to Parent (or to such other person as is directed by Parent), at the times and in the manner set forth in Section 4.4 of this Agreement, cash in an amount equal to such Sun Jupiter Consolidated Member's Separate Return Tax Liability (the "Tax Sharing Amount") in order to reimburse Parent for such Sun Jupiter Consolidated Member's allocable share of the Federal Income Tax Liability of the Sun Jupiter Group.

4.2 Payment of the Consolidated Return Tax Liability. Parent shall pay, on behalf of itself and each Sun Jupiter Consolidated Member, to the Internal Revenue Service the Federal Income Tax Liability of the Sun Jupiter Group in the manner specified by the Code and the Treasury regulations promulgated thereunder.

4.3 Use of Items by the Sun Jupiter Group. For the avoidance of doubt, Parent shall pay any Sun Jupiter Consolidated Member for any Item that reduces the Federal Income Tax Liability of the Sun Jupiter Group.

4.4 Payment of Tax Sharing Amounts.

(a) Tax Sharing Installment Payments. Not later than fifteen (15) days prior to an Estimated Payment Date with respect to any taxable period, each Sun Jupiter Consolidated Member shall provide to Parent a reasonable estimate of the related installments of its Federal Income Tax Liability computed as if such Sun Jupiter Consolidated Member files a separate federal income Tax Return (computed in accordance with any estimated payment method under section 6655 of the Code chosen by Parent) and the basis for such estimate, setting forth the proposed treatment for United States federal income Tax purposes of all Items taken into account in determining such estimate. Parent shall review such estimate, and notify each Sun Jupiter Consolidated Member of any changes to such estimate not later than six (6) days prior to the applicable Estimated Payment Date (such estimate of the related installments, as adjusted by Parent, shall constitute the "Estimated Installment of the Separate Return Tax Liability"). Not later than five (5) days prior to the Estimated Payment Date, each Sun Jupiter Consolidated Member shall pay to Parent (or to such other person as is directed by Parent) the Estimated Installment of the Separate Return Tax Liability (the "Estimated Tax Sharing Amount").

(b) Tax Sharing True-Up Payments. As soon as reasonably practicable after the Consolidated Tax Return for a taxable period is filed, Parent shall deliver to each Sun Jupiter Consolidated Member the information reasonably necessary for such Sun Jupiter Consolidated Member to calculate its Tax Sharing Amount for such taxable period. Within fifteen (15) days after delivery of such information, each Sun Jupiter Consolidated Member shall deliver to Parent a schedule reflecting such Sun Jupiter Consolidated Member's Tax Sharing Amount for such taxable period. Parent shall review such estimate, and shall notify each Sun Jupiter Affiliate of any changes to the schedule as soon as reasonably practicable. Within five (5) days after Parent notifies an Sun Jupiter Consolidated Member of its acceptance of or any changes to the schedule, Parent shall pay to such Sun Jupiter Consolidated Member, or such Sun Jupiter Consolidated Member shall pay to Parent (or to such other person as is directed by Parent), as appropriate, an amount equal to the difference between (i) the sum of the Estimated Tax Sharing Amounts paid by such Sun Jupiter Consolidated Member for such taxable period and (ii) the Tax Sharing Amount set forth with respect to such Sun Jupiter Consolidated Member on the schedule (as adjusted by Parent), together with any interest or penalties assessed on account of such difference by any taxing authority.

4.5 Redetermination of Tax Sharing Amount. If, pursuant to a Final Determination, the treatment of any Item in determining the Sun Jupiter Group's Federal Income Tax Liability for a taxable period is different than that used to calculate any of the Sun Jupiter Consolidated Member's Tax Sharing Amount in respect of such taxable period (including a Final Determination to the effect that a Sun Jupiter Affiliate previously considered an Sun Jupiter Consolidated Member is not an Sun Jupiter Consolidated Member or vice versa), then the amount of any such Tax Sharing Amount (and any Tax Sharing Amounts with respect to prior open years) shall be redetermined by treating such Item in the manner finally determined by Parent, reasonably and in good faith, to be appropriate. The difference between the Tax Sharing Amounts of an Sun Jupiter Consolidated Member and the amounts thereof as redetermined shall be paid within thirty (30) days following such Final Determination by Parent to such Sun Jupiter Consolidated Member, or paid by such Sun Jupiter Consolidated Member to Parent (or to such other person as is directed by Parent), as appropriate, together with interest. Interest shall be computed under section 6621(a)(1) of the Code if the Tax Sharing Amounts are greater than the redetermined amounts, and under section 6621(a)(2) of the Code if the redetermined amounts are greater than the Tax Sharing Amounts. In addition to interest, any such payments shall include penalties which are fairly attributable to the redetermination with respect to such Item.

4.6 Contest. In the event of an audit or administrative or judicial proceeding involving an asserted liability for Taxes (a "Tax Contest") of the Sun Jupiter Group, Parent shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest. To the extent that a Tax Contest involves an Item attributable to a particular Sun Jupiter Consolidated Member, such member will reimburse Parent for all third-party out-of-pocket expenses associated with such Tax Contest that are attributable to such Item.

4.7 Refunds and Credits. Each Sun Jupiter Consolidated Member shall be entitled to all refunds and credits resulting from an Item attributable to such Sun Jupiter Consolidated Member in determining such member's Tax Sharing Amount. Upon receipt of any refund resulting from an Item attributable to a Sun Jupiter Consolidated Member, Parent shall pay over such refund to the applicable Sun Jupiter Consolidated Member.

5. ALLOCATION, PAYMENT AND REFUND OF STATE AND LOCAL TAXES.

5.1 Elections. Parent, in its sole discretion, may elect to have any State Group file a Combined Tax Return.

5.2 Allocation of State or Local Tax. For each state or local jurisdiction in which a State Group files a Combined Tax Return, each Sun Jupiter Combined Member included in such Combined Tax Return shall be liable for and pay to the applicable State Group Head (or to such other person as is directed by Parent), at the times and in the manner set forth in Section 5.5 of this Agreement, cash in an amount equal to such Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group (the "State or Local Tax Sharing Amount") in order to reimburse such State Group Head for such Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group. For purposes of this Section 5.2, each Sun Jupiter Combined Member's allocable share of the Tax liability of such State Group shall be determined in a manner consistent with the principles set forth in Section 4.1 of this Agreement, subject to any comparable provisions of applicable state or local tax law, if any. Any Tax liability not allocated pursuant to the preceding sentence shall be allocated to each Sun Jupiter Combined Member in a manner as if such Tax liability is separately incurred by such Member.

5.3 Payment of State or Local Tax. As directed by Parent, for each state or local Tax jurisdiction in which a State Group files a Combined Tax Return, the relevant State Group Head shall pay, on behalf of itself and each Sun Jupiter Combined Member included in such State Group, the annual Tax liability of the State Group to the state or local taxing authority in accordance with the laws of the state or local jurisdiction.

5.4 Use of Items by the State Group. For the avoidance of doubt, the State Group Head shall pay any Sun Jupiter Combined Member for any Item that reduces the State Group's Tax liability with respect to its Combined Tax Return.

5.5 Computation and Time of Payment. All payments required under Section 5.2 of this Agreement shall be determined and made in a manner consistent with the principles set forth in Section 4.4 of this Agreement; provided, however, that the timing with respect to each installment of a State or Local Tax Sharing Amount shall be determined by applying the rules specified in Section 4.4(a) of this Agreement to the applicable provisions of the relevant state or local tax law.

5.6 Redetermination. If, pursuant to a Final Determination, the treatment of any Item in determining a State Group's tax liability for a taxable period is different than that used under Section 5.2 of this Agreement to calculate the State or Local Tax Sharing Amounts in respect of such taxable period, such State or Local Tax Sharing Amounts (and any State or Local Tax Sharing Amounts with respect to prior open years) shall be redetermined by Parent, and the Sun Jupiter Affiliates shall make such payments as are necessary to comply with the redetermined amount, in a manner consistent with the principles set forth in Section 4.5 of this Agreement.

5.7 Contest. In the event of any Tax Contest involving a State Group, Parent shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest. To the extent that a Tax Contest involves an Item attributable to a particular Sun Jupiter Combined Member, such member will reimburse Parent for all third-party out-of-pocket expenses associated with such Tax Contest that are attributable to such Item.

5.8 Refunds and Credits. Each Sun Jupiter Combined Member shall be entitled to all refunds and credits resulting from an Item attributable to such Sun Jupiter Consolidated Member in determining its State or Local Tax Sharing Amount. Upon receipt of any refund resulting from an Item attributable to a Sun Jupiter Combined Member, Parent shall pay over such refund to the applicable Sun Jupiter Combined Member.

6. PAYMENT AND REFUND OF INDEPENDENT TAX RETURNS

6.1 Tax Liability and Payment. Any Sun Jupiter Affiliate required to file an Independent Tax Return shall pay on its own behalf any Tax liability with respect to such Independent Tax Return to the appropriate taxing authority in accordance with the relevant law.

6.2 Contests. In the event of any Tax Contest involving a Sun Jupiter Affiliate with respect to its Independent Tax Returns, such Sun Jupiter Affiliate shall have the sole right to decide whether to contest such Tax Contest, and shall have full control over such Tax Contest.

6.3 Refunds. Each Sun Jupiter Affiliate shall be entitled to all refunds and credits with respect to its Independent Tax Returns.

7. DECONSOLIDATION EVENTS.

7.1 Tax Allocations. Although no Sun Jupiter Affiliate has any plan or intent to effectuate any transaction that would constitute a Deconsolidation Event, the Sun Jupiter Affiliates have set forth how certain Tax matters with respect to a Deconsolidation Event would be handled in the event that, as a result of changed circumstances, a transaction that constitutes a Deconsolidation Event occurs at some future time.

7.2 Allocation of Tax Items. In the case of a Deconsolidation Event, all Tax computations for (1) any Pre-Deconsolidation Periods ending on and including the date of the Deconsolidation Event and (2) the immediately following taxable period of applicable Sun Jupiter Affiliate(s), shall be made pursuant to the principles of section 1.1502-76(b) of the Treasury Regulations or of a corresponding provision under the laws of other applicable jurisdictions, determined by Parent. Parent shall be entitled to make any election allowable under section 1502 of the Code and any Treasury regulations promulgated thereunder in respect of the Deconsolidation Event, including, without limitation, any election pursuant to section 1.1502-36 of the Treasury regulations, and any corresponding provisions under the laws of other applicable jurisdictions, determined by Parent.

7.3 Allocation of Tax Assets. In the case of a Deconsolidation Event, the applicable Sun Jupiter Affiliate and the remaining members of the Sun Jupiter Group shall cooperate in determining the allocation of any Tax Assets among each of the Sun Jupiter Affiliates. All Sun Jupiter Affiliates agree that in the absence of controlling legal authority or unless otherwise provided under this Agreement, Tax Assets shall be allocated to the legal entity that is required under Section 4 and Section 5 of this Agreement to bear the liability for the Tax associated with such Tax Asset, or in the case where no party is required hereunder to bear such liability, the party that incurred the cost or burden associated with the creation of such Tax Asset.

8. RESTRICTION ON PAYMENTS.

If an Sun Jupiter Affiliate is prohibited from making a payment as required by Section 4 or Section 5 of this Agreement by law or contractual obligation, and such prohibition is so acknowledged by Parent, then no such payment will be made under such Sections (collectively, the "Payment Sections"). Parent shall, however, keep an account reflecting the net balance of payments that would have been made had payments been made under the Payment Sections (the "Payment Account"). For purposes of keeping such account, interest shall be computed under section 6621(a)(1) of the Code if money is owed to Parent and under section 6621(a)(2) of the Code if money is owed to an Sun Jupiter Affiliate. If a prohibition referenced in the first sentence of this Section 8 is eliminated, then the affected Sun Jupiter Affiliate shall notify Parent in a timely manner, and within ten (10) days of such notification the amount reflected in the Payment Account shall be paid to Parent or the Sun Jupiter Affiliate, as appropriate.

9. CHANGE IN LAW.

If, after the date this Agreement is executed and delivered, as a result of an amendment to the Code, the promulgation of proposed, temporary or final regulations, the issuance of a ruling by the Internal Revenue Service, the decision of any court, or a change in any comparable applicable state or local Tax law, Parent believes that it is necessary or helpful to amend the provisions of this Agreement in order to preserve the rights and benefits contemplated herein, each of the Sun Jupiter Affiliates agrees to negotiate in good faith all such amendments and modifications as shall be necessary or appropriate in order to preserve as nearly as possible for the Sun Jupiter Affiliates the rights and benefits contemplated herein. Notwithstanding the preceding sentence, in the event of an amendment to section 6655(c) of the Code (or a comparable provision under state or local Tax law), this Agreement shall be amended so that the timing and amounts of Tax Sharing Amounts and/or State or Local Tax Sharing Amounts shall be revised to conform to such amendment.

10. COOPERATION.

Each Sun Jupiter Affiliate shall: (i) furnish Parent or the applicable State Group Head in a timely manner such information and documents as Parent or the applicable State Group Head may request for purposes of (A) preparing any Tax Return for which Parent or the applicable State Group head has filing responsibility under this Agreement, (B) evaluating, contesting, or defending any Tax Contest, and (C) making any determination or computation necessary or appropriate under this Agreement; (ii) make its employees available to provide explanations of documents and other materials and such other information as Parent or the applicable State Group Head may reasonably request in connection with the foregoing; (iii) cooperate in any Tax Contest of a Consolidated Tax Return or Combined Tax Return; (iv) retain and provide on demand books, records, documentation, or other information relating to any Tax Return until ninety (90) days after the expiration of the applicable statute of limitations (giving effect to any extension, waiver, or mitigation thereof); and (v) take such other actions as Parent or the applicable State Group Head may reasonably deem appropriate in connection therewith.

11. GENERAL PROVISIONS.

11.1 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

11.2 Notices. All notices or other communications required or permitted hereunder shall be in writing and shall be deemed given or delivered when delivered personally or when sent by registered or certified mail in accordance with the names and addresses shown on Schedule A, or in accordance with such name and address as a Sun Jupiter Affiliate may indicate by a notice delivered to the other Sun Jupiter Affiliates.

11.3 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of all the Sun Jupiter Affiliates and their respective successors and assigns. Nothing herein, expressed or implied, is intended or may be construed to confer upon any person other than the Sun Jupiter Affiliates and their successors and assigns any right, remedy or claim under or by reason of this Agreement.

11.4 Duration. Unless terminated earlier by agreement of all Sun Jupiter Affiliates, this Agreement shall remain in force and effect for all taxable periods for which any Sun Jupiter Group files Consolidated Tax Returns or any State Group files Combined Tax Returns. Notwithstanding any termination of this Agreement, the provisions hereof shall remain in effect (and each Sun Jupiter Affiliate shall continue to have all of the rights and obligations hereunder) with respect to any taxable period (or portion thereof) preceding the date of such termination.

11.5 New Affiliates. If at any time any other entity becomes an affiliate of Parent or the applicable State Group Head, such entity may become a party to this Agreement by executing together with Parent or the applicable State Group Head an agreement in substantially the same form as set forth in Schedule B. Unless otherwise specified, such new entity shall have all rights and obligations of an Sun Jupiter Affiliate under this Agreement.

11.6 Affiliates. Each Sun Jupiter Affiliate shall cause to be performed, and hereby guarantees the performance of, all actions, agreements and obligations set forth herein to be performed by any of the Sun Jupiter Affiliates.

11.7 Authorization, Etc. Each of the Sun Jupiter Affiliates hereby represents and warrants that is has the power and authority to execute, deliver and perform this Agreement, that this Agreement has been duly authorized by all necessary corporate action on the part of such Sun Jupiter Affiliate, that this Agreement constitutes a legal, valid and binding obligation of such Sun Jupiter Affiliate and that the execution, delivery and performance of this Agreement by such Sun Jupiter Affiliate does not contravene or conflict with any provision of law or of its charter or bylaws or any agreement, instrument or order binding on such Sun Jupiter Affiliate.

11.8 Entire Agreement; Amendments. This Agreement contains the entire understanding of the Sun Jupiter Affiliates with respect to the subject matter hereof and supersedes all prior agreements, understandings and intentions between or among any of the Sun Jupiter Affiliates. The Sun Jupiter Affiliates may amend, modify or supplement this Agreement, but only by mutual agreement in writing.

11.9 Headings. The headings and subheadings used in this Agreement are used for convenience of reference only and are not to be considered in construing or interpreting this Agreement.

11.10 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

[Remainder of Page Intentionally Blank]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the dates accompanying their respective signatures, but effective as of the date first above written.

Sun Jupiter Topco LLC

By: ____________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

Sun Jupiter Parent LLC

By: ____________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

Sun Jupiter Holdings LLC

By: ____________________
Name: Preston T. Scherer
Title: Authorized Signatory
Dated: July 29, 2020

El Paso Electric Company

By: ____________________
Name: ____________________
Title: ____________________
Dated: ____________________

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on the dates accompanying their respective signatures, but effective as of the date first above written.

Sun Jupiter Topco LLC

By: ____________________
Name: ____________________
Title: ____________________
Dated: ____________________

Sun Jupiter Parent LLC

By: ____________________
Name: ____________________
Title: ____________________
Dated: ____________________

Sun Jupiter Holdings LLC

By: ____________________
Name: ____________________
Title: ____________________
Dated: ____________________

El Paso Electric Company

By: Nath T. H-
Name: Nathan T. Hirschi
Title: Senior Vice President and Chief Financial Officer
Dated: July 29, 2020

Schedule A

Sun Jupiter Topco LLC (EIN: 84-2665086)
277 Park Avenue 35th Floor
New York, NY 10172

Sun Jupiter Parent LLC (EIN: 84-2641326)
277 Park Avenue 35th Floor
New York, NY 10172

Sun Jupiter Holdings LLC (EIN: 61-1933163)
277 Park Avenue 35th Floor
New York, NY 10172

El Paso Electric Company (EIN: 74-0607870)
P.O. Box 982, Loc 112
El Paso, TX 79960

Schedule B

WHEREAS, Sun Jupiter Topco LLC, a Delaware limited liability company ("Parent"), owns, directly or indirectly, all of the outstanding stock or interests in the undersigned;

WHEREAS, the undersigned is not a party to the Tax Sharing Agreement, made and entered into as of July 29, 2020, by and among Parent and each of the Sun Jupiter Affiliates (as defined therein) (the "Agreement"); and

WHEREAS, the undersigned and Parent desire to have their tax sharing and other tax-related arrangements governed by the Agreement.

NOW, THEREFORE, in consideration of mutual obligations and undertakings contained in the Agreement, the parties agree that tax sharing and other tax-related arrangements between and among the undersigned and the other Sun Jupiter Affiliates will be governed by the terms of the Agreement, and that the Agreement is hereby amended to include the name of the undersigned among the entities listed thereon.

IN WITNESS WHEREOF, the parties have executed this agreement on the dates accompanying their respective signatures, but effective as of ______________.

[NAME]	**Sun Jupiter Topco LLC**
By: ________________________	By: ________________________
Title: ______________________	Title: ______________________
Dated: _____________________	Dated: _____________________

Docket NO. 57568

APPLICATION OF EL PASO	§	PUBLIC UTILITY COMMISSION
ELECTRIC COMPANY TO CHANGE	§	OF TEXAS
RATES	§	

DIRECT TESTIMONY

OF

VICTOR MARTINEZ

FOR

EL PASO ELECTRIC COMPANY

JANUARY 2025

EXECUTIVE SUMMARY

Victor Martinez is the Director of Energy Resources for El Paso Electric Company ("EPE" or "Company"). He oversees the sales and purchases of power in the energy imbalance, real-time, day ahead, intermediate, and long-term power markets, fuel procurement and strategy, Renewable Energy Credits, and emission allowances as well as EPE's stake in the Palo Verde Generating Station ("Palo Verde").

Mr. Martinez's testimony addresses the value of capacity that should be imputed to long - term renewable energy contracts in accordance with the settlement and order in Docket No. 46831, and he supports EPE's rate base request for capacity charges for the 50 megawatt battery energy storage system that is part of a system purchased power agreement for the Buena Vista 1 generation facility which began serving Texas customers in July 2023.

Mr. Martinez also supports EPE's request to include 100% of the capital investment made in its new Newman Unit 6 combustion turbine power plant which went into commercial operation on December 27, 2023, and has been used exclusively to serve Texas customers. In addition, Mr. Martinez sponsors and describes an analysis performed by his team regarding the economics of accelerating the construction of Newman Unit 6 to reach commercial operation by summer 2023 compared to the cost of purchasing the capacity and energy on the market.

Mr. Martinez discusses EPE's joining and participation in the Energy Imbalance Market ("EIM") run by the California Independent System Operation, and how EPE's participation in the EIM market benefits its customers to support EPE's request to recover Test Year EIM expenses. He also supports EPE's rate base request for upgrades to EPE's Energy Management System, addressing the reasonableness and necessity of the upgrade cost and the resulting benefits to EPE's customers. He also sponsors and describes an analysis performed by his team to determine the value of Newman Unit 3 upgrades addressed in the Direct Testimony of David Rodriguez.

In addition, Mr. Martinez supports the reasonableness of the capital additions placed in service at Palo Verde from January 1, 2021, through September 30, 2024, together with the reasonableness of the Palo Verde Test Year operations and maintenance expenses.

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EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Victor Martinez, and my business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. BY WHOM ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company").

Q3. WHAT IS YOUR CURRENT POSITION WITH EPE?

A. I am Director of Energy Resources.

Q4. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF ENERGY RESOURCES?

A. I act in a supervisory capacity over Company employees responsible for the sales and purchases of power in the energy imbalance, real-time, day ahead, intermediate, and long - term power markets, fuel procurement and strategy, Renewable Energy Credits, and emission allowances. My primary responsibilities are to ensure that the transactions entered into by the Company employees reporting to me are within the parameters approved by executive management, to assist in the identification of opportunities to maximize the Company's energy resources and minimize fuel and purchased power costs, and to provide guidance as the Company explores opportunities resulting from changes in regulatory rules and policies. I am also responsible for representing the Company in various regulatory proceedings and processes in its Texas and New Mexico jurisdictions as well as at the Federal Energy Regulatory Commission. Lastly, I oversee EPE's stake in the Palo Verde Generating Station ("Palo Verde" or "PVGS").

Q5. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. In 2004, I graduated from the University of Texas at El Paso with a Bachelor of Business Administration degree in Computer Information Systems and International Business.

Q6. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. In April 2005, I began working for EPE in the position of Real Time Power Marketer, where my duties included evaluating and balancing EPE's bulk electrical system through the hourly purchase and sale of energy in the wholesale market. In addition, my duties included the purchase of supplemental power to decrease generation costs for EPE customers while working closely with EPE's System Operations and Power Generation divisions to maintain a reliable, safe, and cost-effective electrical system.

In May 2012, I was promoted to Senior Forward Marketer for Long-term Trading and Fuels. The Long-term Trading and Fuels group is responsible for long-term wholesale power transactions, natural gas contract negotiations, and PROMOD model base cases for financial planning. My duties as a Forward Marketer included procuring natural gas on a monthly and mid-term basis, assisting with nuclear fuel contracts, and estimating long - term natural gas requirements, along with future market prices, to maintain an economic and reliable fuel supply.

In May 2014, I was promoted to Interim Supervisor for Real Time Trading. In that capacity, I oversaw operations for all real-time power trading activity.

In August 2014, I was promoted to Supervisor of Day Ahead and Long - term Trading. My responsibilities included maximizing the value of EPE's assets through power sales and purchases, system fuel purchases, Renewable Energy Certificates, and emissions transactions. I also oversaw the analyses and evaluation of potential day-ahead, intermediate, and long-term agreements for purchase and sale of energy. I supervised the development and evaluation of standard and non-standard deal structures to maximize EPE's resources and minimize fuel and purchased power costs. Additionally, I provided guidance in negotiations of inter-utility, power marketer, fuel provider, and power producer contractual matters.

In January 2020, I was promoted to Manager of Resource Planning, Resource Management Regulatory and Quality Assurance. My responsibilities included managing and supervising the Resource Planning department, which is responsible for leading EPE's resource planning duties and activities to obtain an optimal mix of supply - side and demand - side resources that cost-effectively and reliably meet the Company's near - term and long - term forecasted annual peak and energy demand requirements. In that capacity, I interfaced with EPE's Economic Forecasting, Transmission, Operations, Regulatory, and

Energy Efficiency departments, among others, and stakeholder groups to incorporate short-term and long-term considerations into EPE's Integrated Resource Plan. Furthermore, I managed and supported EPE's Resource Planning's Request for Proposal ("RFP") processes to identify, select, procure, and implement the development of new generation resources to fulfill EPE's customer demand and regulatory requirements. In this capacity, I verified the inputs into the Company's PLEXOS and AURORA capacity expansion models and assisted with and corroborated the reasonableness of those analyses. In September 2023, I was promoted to my current role as Director of Energy Resources.

Q7. HAVE YOU EVER PROVIDED TESTIMONY IN A REGULATORY PROCEEDING?

A. Yes, I have filed testimony before the Public Utility Commission of Texas ("PUCT" or "Commission") and the New Mexico Public Regulation Commission ("NMPRC").

II. Purpose of Testimony

Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present EPE's proposal regarding the value of capacity that should be imputed to long - term renewable energy contracts in accordance with the settlement and order in Docket No. 46831. I also provide testimony regarding the capacity charges for the 50 - megawatt ("MW") battery energy storage system ("BESS") that is part of the Buena Vista 1 purchased power agreement ("PPA")[1] that EPE executed in 2019, and which began serving customers in July 2023. The Buena Vista 1 PPA was chosen out of the Company's 2017 competitive solicitation process as part of the lowest-cost portfolio of generation resources to help meet EPE's capacity and energy needs.

My testimony also supports EPE's request to include in rate base 100% of the capital investment made in the Newman Unit 6 combustion turbine power plant. Newman Unit 6 has been used exclusively to serve Texas customers since it reached commercial operation on December 27, 2023. The NMPRC rejected a CCN application for Newman Unit 6 because it was not a renewable generation resource, and EPE subsequently selected the New Mexico jurisdictional portion of that unit through a competitive solicitation process as part of the least-cost portfolio of resources to meet EPE's growing Texas

[1] Buena Vista 2 is a PPA for a 20-megawatt solar facility dedicated to serve EPE's New Mexico jurisdiction.

capacity needs. Further, I describe an analysis performed by my team which demonstrated the favorable economics of accelerating the construction of Newman Unit 6 to reach commercial operation by the summer of 2023 compared to the cost of purchasing the capacity and energy on the market.

My testimony also explains EPE's joining and participation in the Energy Imbalance Market ("EIM") run by the California Independent System Operation ("CAISO"), how EPE's participation in the EIM benefits its customers, and the costs incurred during the Test Year related to the Company's participation in the EIM for which EPE requests recovery through base rates. I also discuss the recent upgrade of EPE's Energy Management System ("EMS") made to support EPE's participation in the EIM, the benefits to EPE customers from the EMS upgrade, and the reasonableness and necessity of the costs associated with the EMS upgrade. In addition, my testimony describes an analysis performed by my team to determine the value of certain upgrades made during the Test Year at EPE's Newman Unit 3.

Finally, I describe the capital additions placed in service at Palo Verde from January 1, 2021, through September 30, 2024, together with the Palo Verde Test Year operations and maintenance ("O&M") expenses and explain why those capital additions and O&M costs were reasonable and prudent.

Q9. WHAT EXHIBITS AND SCHEDULES DO YOU SPONSOR?

A. The exhibits that I sponsor are identified in the Table of Contents of this testimony. The schedules that I sponsor, or co-sponsor are identified in Exhibit VM-1.

Q10. WERE THE SCHEDULES AND EXHIBITS THAT YOU SPONSOR OR CO-SPONSOR PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. Capacity Costs

Q11. IS EPE REQUESTING TO INCLUDE PURCHASED POWER CAPACITY COSTS IN EPE'S COST OF SERVICE?

A. Yes. Consistent with the Final Order in Docket No. 46831, EPE seeks to include capacity costs associated with two renewable energy PPAs the Company uses to serve Texas customers: the Macho Springs 50-megawatt ("MW") solar agreement, which began commercial operation in May 2014, and the Newman solar agreement ("Newman Solar"), which began in December 2014. EPE also requests to include the capacity charge from the Buena Vista 1 PPA for the 100-MW solar coupled with 50 MW BESS, which began commercial operation in July 2023. I present the imputed capacity costs associated with the Macho Springs and Newman contracts that were agreed to in Docket No. 46831, and EPE witness Julissa Reza sponsors the adjustment to reflect the revised costs in the Company's cost of service. I also present the capacity costs included in the Buena Vista 1 PPA for the 50 MW BESS portion of the facility and support on why those costs are reasonable and prudent.

Q12. DO THESE PURCHASED POWER AGREEMENTS INCLUDE SPECIFIED CAPACITY CHARGES?

A. The Macho Springs and Newman Solar PPAs do not, but the Buena Vista 1 PPA does include specified capacity costs for the 50 MW BESS.

Q13. ARE THERE OTHER PPAs INCLUDED IN EPE'S CURRENT L&R WHICH CONTRIBUTE TO EPE'S PLANNING RESERVE MARGIN?

A. Yes. However, EPE is not seeking to recover any associated capacity charges from those other PPAs as part of its Texas jurisdictional cost of service. These other PPAs are dedicated and entirely allocated to the New Mexico jurisdiction because they were procured under the New Mexico Renewable Energy Act for the New Mexico Renewable Portfolio Standard ("RPS"). All the costs for these contracts are recovered from New Mexico customers through the New Mexico RPS Cost Rider. To the extent that EPE enters additional renewable PPAs to meet specific increases in the New Mexico RPS, those costs too shall be entirely recovered from New Mexico customers.

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A. Macho Springs and Newman Solar PPAs

Q14. DID THE SETTLEMENT AGREEMENT AND ORDER IN DOCKET NO. 46831 SPECIFY HOW THE MACHO SPRINGS AND NEWMAN SOLAR PPAs WOULD BE TREATED FOR RATEMAKING PURPOSES?

A. Yes, they did. Article I.F of the Docket No. 46831 settlement agreement, titled "Imputed Capacity", specifies the rate treatment of these two PPAs as follows:

> The Signatories agree that the classification of costs incurred by EPE as either base rate capacity charges or fuel charges for the 50 MW Macho Springs solar PPA and the 10-MW Newman solar PPA shall be as follows for the term of these contracts: Effective beginning August 1, 2017, the imputed capacity charge for the 50 MW Macho Springs solar PPA shall be $2.35/kW per month, and the imputed capacity charge for the 10 MW Newman solar PPA shall be $2.33/kW per month. All remaining costs incurred under these two PPAs shall be classified as fuel expenses.

Finding of Fact 33 in the Commission's final order adopted this provision of the settlement agreement.

Q15. DOES EPE'S PROPOSED RATE TREATMENT OF THE MACHO SPRINGS AND NEWMAN SOLAR PPAs COMPLY WITH THE DOCKET NO. 46831 AGREEMENT AND ORDER?

A. Yes, it does. Specifically, EPE has imputed capacity charges of $2.35 per kilowatt ("kW") per month to the Macho Springs PPA and $2.33 per kW per month to the Newman Solar PPA. The resulting Test Year capacity charges have been included in EPE's cost of service.

B. Buena Vista 1 PPA

Q16. WHAT ARE THE CAPACITY CHARGES ASSOCIATED WITH THE BUENA VISTA 1 PPA THAT EPE SEEKS TO INCLUDE IN ITS COST OF SERVICE?

A. Pursuant to the terms of the Buena Vista 1 PPA, EPE is incurring a charge of $5.46 per kW per month for the capacity provided by the Buena Vista BESS, the jurisdictional portion of which is included in EPE's proposed cost of service. EPE witness Adrian Hernandez addresses jurisdictional allocations.

Q17. WHAT LED TO THE COMPANY'S DECISION TO ENTER INTO THE BUENA VISTA 1 PPA THAT INCLUDED THE BESS?

A. By 2017, EPE's resource planning processes had identified a need for additional generation in EPE's system to address continued load growth and the planned retirements of three natural gas steam units that were at the end of their useful lives, and to ensure that the Company's planning reserve margin would be met. Therefore, the Company's Resource Planning Department issued the 2017 All-Source RFP in June 2017 soliciting proposals for supply-side or demand-side resources, or both. The RFP was open to all types of generation technologies except baseload generation such as coal or nuclear. The objective of the 2017 RFP was to obtain proposals for resources and evaluate those proposals to identify the most cost-effective resource or portfolio of resources that could reliably meet the energy and capacity needs of EPE's customers. EPE contracted with an Independent Evaluator ("IE") to oversee the RFP process and ensure that the solicitation was conducted fairly and impartially and resulted in a selection of proposals that would provide EPE customers with reliable service at the lowest reasonable cost.

Q18. WHAT WAS THE RESPONSE FROM THE MARKET TO THE 2017 ALL-SOURCE RFP?

A. In response to the 2017 All-Source RFP, the Company received 81 different proposals from 36 different bidders for a large variety of resource types and capacity options. There were a substantial number of wind, solar and battery storage resources (and combinations thereof) bid into the RFP, and the costs of those resources on a $/MWh basis as proposed had decreased from prior RFPs that EPE had issued, to the point that they were more cost competitive compared to traditional thermal resources. EPE bid its own self-build combustion turbine proposal into the RFP, which was ultimately chosen for its ability to help EPE meet peak load requirements and became Newman Unit 6. The details regarding the development and construction of Newman Unit 6 are discussed in more detail in the direct testimony of EPE witness David Rodriguez, and EPE witness Ellen Smith also discuss the costs incurred by EPE in bringing Newman Unit 6 to commercial operation in December 2023. Later in my testimony I discuss the reasons and justification for the dedication of Newman Unit 6 as a generation resource to exclusively serve EPE's Texas customers.

Q19. CAN YOU EXPLAIN MORE ABOUT THE BATTERY STORAGE OPTIONS BID INTO THE RFP?

A. Yes. All storage options available from the 2017 RFP process were battery storage, and most of those options were lithium-ion battery storage systems. These battery storage options offer firming of intermittent renewable generation for peak hour utilization and provide load shifting of energy capacity and non-dispatchable renewable resources to peak hours.

Q20. CAN YOU SUMMARIZE THE PROCESS USED BY EPE TO EVALUATE THE BIDS RECEIVED?

A. EPE, with oversight from the IE, undertook a consistent multi-stage evaluation process consisting primarily of the following steps: eligibility and threshold requirements, non - economic qualitative assessment (including project development feasibility, resource reliability, project operational viability, operational characteristics, and proposal flexibility), and economic evaluation.

The economic evaluation involved the calculation of the levelized cost of energy ("LCOE") for each proposal. LCOE is an effective and appropriate tool for ranking resources within each respective resource technology type since they have similar operational and performance characteristics. As a result, EPE evaluated resources in groupings by resource technology type and ranked all similar proposals by category.

The LCOE rankings in conjunction with the qualitative review were utilized to develop a bidder shortlist. Shortlisted bidders were requested to submit their best and final proposals, which were then re-evaluated via the LCOE methodology and re-ranked within respective technology type categories as previously explained. The LCOE rankings by categories aided in determining which proposals were modeled into EPE's expansion planning software. EPE also used a new modeling tool that performs production cost modeling at a much more detailed level to help examine how resources would be dispatched and utilized in a dynamic production model. The modeling results were utilized to determine the least cost optimized resource plan. The IE reviewed the evaluation to make sure there was no bias toward any self-build option.

Q21. WHAT WERE THE RESULTS OF THE EVALUATION OF THE BIDS FROM THE 2017 ALL-SOURCE RFP?

A. The portfolio of resources ultimately chosen out of the RFP included Newman Unit 6, the Buena Vista I PPA and two other PPAs for a solar and a battery storage facility, respectively.[2] The RFP analysis showed that these resources could be integrated into EPE's system safely and reliably, and that the portfolio was the optimal lowest-cost alternative available through the competitive solicitation process to meet summer peaking and overall system reliability requirements. The IE confirmed that EPE conducted the RFP fairly, consistently and without bias, and that the selected resources would provide EPE customers with cost-effective, reliable electric service.

Q22. ARE THE CAPACITY COSTS OF THE BUENA VISTA 1 PPA 50 MW BESS INCURRED DURING THE TEST YEAR REASONABLE AND PRUDENT?

A. Yes, they are. The capacity cost of $5.46/kW-month that EPE is incurring monthly is competitively priced and well below the current market. According to the Lazard Levelized Cost of Energy Report published in June 2024, the levelized cost of utility-scale standalone 4-hour storage systems ranged between $13/kW-month to $23.67/kW-month. This subsidized price range assumes that projects will qualify for the full Investment Tax Credit ("ITC"); the capacity cost for the Buena Vista 1 BESS was agreed to prior to the implementation of the ITC. The BESS component of the Buena Vista 1 PPA will provide reliable and economic capacity to EPE customers over the expected 20-year service life of the facility.

IV. Newman Unit 6

Q23. YOU MENTIONED NEWMAN UNIT 6 WAS SELECTED AS PART OF THE LOWEST COST PORTFOLIO OF RESOURCES FROM THE 2017 ALL-SOURCE RFP.

[2] EPE ultimately did not pursue the battery storage PPA after the NMPRC denied the Company's request for approval of the project, and the counterparty to the solar PPA defaulted on the agreement.

WAS NEWMAN UNIT 6 SELECTED AS A SYSTEM RESOURCE?

A. Yes, it was. The 2017 All-Source RFP was performed to solicit resources that could serve EPE's capacity and energy needs on a systemwide basis, including the expected demand from both its Texas and New Mexico jurisdictional customers.

A. Designation as a Texas-Dedicated Resource

Q24. IS EPE REQUESTING THAT THE COMMISSION INCLUDE IN TEXAS RATE BASE ALL OF THE COSTS INCURRED TO BRING NEWMAN UNIT 6 INTO SERVICE?

A. Yes. EPE seeks to include in its Texas rate base approximately $217.3 million, which is the total amount of capital invested in Newman Unit 6 to place the unit into service.

Q25. HAS NEWMAN UNIT 6 BEEN UTILIZED BY EPE AS A SYSTEM RESOURCE SINCE BEING PLACED INTO SERVICE?

A. No, it has not. After Newman Unit 6 was selected as part of the lowest cost portfolio of resources bid into the 2017 All-Source that could reliably help meet EPE's needs, EPE sought regulatory approval of the unit from both the Commission and the NMPRC. After the Commission approved EPE's request to amend its Certificate of Convenience and Necessity ("CCN") to include Newman Unit 6,[3] the NMPRC rejected EPE's CCN application to approve Newman Unit 6 to serve the Company's New Mexico customers.[4] Therefore, since Newman Unit 6 went into commercial operation on December 27, 2023, it has been used exclusively to serve the needs of EPE's Texas customers.

Q26. WAS IT IN THE BEST INTERESTS OF EPE CUSTOMERS TO USE 100% OF NEWMAN UNIT 6 TO SERVE TEXAS CUSTOMERS?

A. Yes, it was. In 2021, after the NMPRC denied EPE's application for approval to utilize the New Mexico jurisdictional portion of Newman Unit 6 (approximately 42 MW of capacity)

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[3] *Application of El Paso Electric Company to Amend Its Certificate of Convenience and Necessity for an Additional Generating Unit at the Newman Generating Station in El Paso County and the City of El Paso*, Docket No. 50277, Order (Oct. 16, 2020).

[4] *In the Matter of El Paso Electric Company's Application for A Certificate of Public Convenience and Necessity to Construct, Own, and Operate Generating Unit 6 at the Newman Generating Station*, Docket No. 19-00349-UT, Order Adopting Recommended Decision with Additional Instruction (Dec. 16, 2020).

to serve EPE's New Mexico customers, EPE's Resource Planning department determined that the Company would need additional capacity beginning in 2022 to serve Texas customers due to continued load growth, another planned resource that was denied authorization by the NMPRC, another planned resource that was significantly delayed, and the planned retirement of several aging conventional gas-fired generation units. Using the capacity of the New Mexico jurisdictional portion of Newman Unit 6 to serve Texas customers was determined to be part of a low-cost resource portfolio to meet those incremental capacity needs.

Q27. HOW DID EPE DETERMINE THAT USING 100% OF NEWMAN UNIT 6 WAS NECESSARY TO MEET ITS TEXAS CUSTOMER NEEDS?

A. As part of EPE's ongoing resource planning processes, the Company develops its Loads and Resources ("L&R") document on an annual basis to reflect the surplus or deficiency of EPE generating and purchased power resources versus expected loads, considering EPE's planning reserve margin and assuming no new capacity is added.[5] In addition to the capacity need that started in 2022, the Company's 2021 Texas L&R document also demonstrated that EPE will be 76 MW short in meeting the 2023 summer peak, and that a total of 129 MW and 250 MW will be needed by the summers of 2025 and 2028, respectively, to meet increasing electricity demand from Texas customers and meet the planning reserve margin, and to a lesser extent, to replace the retirement of older, less efficient generating units. Therefore, EPE issued its 2021 Texas RFP seeking competitive proposals that would allow EPE to meet its future load growth and reliably meet its planning reserve margin. The primary objective of the 2021 Texas RFP was to identify the most cost - effective resource(s) to reliably address the capacity needs of Texas customers. EPE bid into the RFP the remaining 42 MW portion of Newman Unit 6 that would have gone to serve its New Mexico customers as a potential resource to serve the growing Texas load. After a comprehensive evaluation of the 35 different resource proposals that were bid into the 2021 Texas RFP, with every eligible bid scrutinized in detail based on threshold,

[5] Previously the Company developed its L&R document on a system-wide basis, but starting in 2021, as part of developing its integrated resource plan for New Mexico, EPE determined that given the differing regulatory requirements between Texas and New Mexico, developing separate jurisdictional L&Rs and conducting separate resource solicitations was the best approach to efficient resource selection and regulatory approvals.

quantitative, and qualitative criteria, EPE determined that the remaining portion of Newman Unit 6, which was the only gas-fired combustion turbine bid into the Texas 2021 RFP, was part of the lowest-cost portfolio of resource that would help reliably meets the capacity needs of the Company's Texas customers. The IE that EPE contracted to monitor and oversee the 2021 Texas RFP concurred with EPE's decision to select the remaining 42 MW portion of Newman Unit 6 as part of the lowest-cost resource portfolio.

Q28. SINCE EPE'S SELECTION OF THE PORTION OF NEWMAN UNIT 6 OTHERWISE ALLOCATED TO THE NEW MEXICO RETAIL JURISDICTION AS A RESOURCE TO SERVE THE ELECTRICITY NEEDS OF EPE'S TEXAS CUSTOMERS, HOW HAS EPE'S SYSTEM PLANNING TREATED THAT RESOURCE FOR PLANNING PURPOSES?

A. EPE has treated it as a resource that is dedicated to serving Texas load. In other words, in determining the need for additional resources to serve Texas load, the entire capacity of Newman Unit 6 has been included in the capacity available to serve Texas load. EPE did not dispose of that capacity by selling it off but instead kept it available to serve Texas customers and has used it to meet Texas customers' demand.

Q29. HYPOTHETICALLY, HOW WOULD EPE'S RESOURCE PLANNING FOR TEXAS LOAD REQUIREMENTS BE DIFFERENT IF 100% OF NEWMAN UNIT 6 WAS NOT AVAILABLE TO SERVE THE NEEDS OF EPE'S TEXAS CUSTOMERS?

A. If all the Newman Unit 6 capacity was not available to serve the needs of EPE's Texas customers (for instance, if the NMPRC had certificated the unit to serve New Mexico customers, or if EPE had sold an undivided interest to another entity or used the New Mexico jurisdictional portion as merchant generation), Texas customers would be approximately 42 MW shorter on the capacity needed to serve them. In practical terms, in EPE's most recent 2023 RFP that solicited bids for resources to serve Texas load, EPE would have been looking to secure an additional 42 MW of capacity to fill the void left by the absence of that portion of Newman Unit 6.

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B. Analysis of Acceleration Change Order

Q30. WHEN WAS NEWMAN UNIT 6 SCHEDULED TO BE PLACED INTO SERVICE FOR EPE CUSTOMERS?

A. Newman Unit 6 was initially scheduled for commercial operation in June of 2023 to help EPE meet its summer peak load requirements. However, there were some delays in the construction and commissioning schedule for the unit due to many distinct factors, which are discussed in more detail in the direct testimonies of EPE witnesses Rodriguez and Smith. These included late equipment deliveries caused by the COVID-19 pandemic, supply chain disruptions and technical issues. As a result, by early 2023 it became clear that there would need to be some major changes in construction staffing to meet the June commercial operation target.

Q31. HOW DID EPE DECIDE HOW TO ADDRESS THE DELAYS IN THE CONSTRUCTION AND COMMISSIONING OF NEWMAN UNIT 6?

A. Casey-MasTec, the general contractor for the project, proposed to add additional laborers, expand overtime, and add a second night shift of workers as an option for keeping the project on its initial schedule for a commercial operation date of June 21, 2023. The rough order of magnitude of these changes, together with the delay costs and impacts, was estimated by Casey-MasTec at approximately $13.9 million. My team in Resource Planning then performed a fuel and purchased power cost impact analysis to determine whether the increase in fuel and purchased power costs that EPE would incur if the commercial operation date for Newman Unit 6 was delayed past the summer peak season would be greater than the estimated $13.9 million cost to accelerate the construction of the unit to try and get it into service by June.

Q32. HOW WAS THAT COST IMPACT ANALYSIS PERFORMED?

A. The Resource Planning team ran a base case together with a series of sensitivities using the Aurora production cost model to estimate the cost impact of delaying the Newman Unit 6 commercial operation date ("COD") from a fuel and purchased power perspective. The base case and all sensitivities assumed the original June 21, 2023, COD and the 2023 fuel and purchased power budget with opportunity sales, updated with gas and Palo Verde market prices using the price curve dated January 18, 2023. The sensitivities were based on the length of time delay for the COD for Newman Unit 6, and during each period of time EPE replaced the unit's capacity (based on its effective load carrying capability) with equivalent heavy load forward market purchases through the summer peak season.

Q33. WHAT WERE THE RESULTS OF THE COST IMPACT ANALYSIS?

A. The analysis showed that delaying Newman Unit 6's COD from June 2023 to September 2023 would likely result in required heavy load purchase power costs that exceeded the cost of accelerating the construction of Newman Unit 6 by over $10 million. It indicated that the prices of the heavy load purchased power would increase over the summer peak period. Therefore, Resource Planning recommended that EPE contract with Casey-MasTec to accelerate the project. A copy of a memo that I sent to EPE witness Rodriguez, the leader of the Newman Unit 6 team at the time of completion of the analysis, is attached to my testimony as Exhibit VM-02.

V. Miscellaneous Issues

A. EIM

Q34. HAS EPE TAKEN ADDITIONAL STEPS RECENTLY TO INCREASE THE EFFICIENCY AND RELIABILITY OF ITS SYSTEM?

A. Yes. EPE continuously strives to operate its system in an economical manner by operating its most efficient units while maintaining reliability. Specifically, EPE seeks to purchase power when it can be purchased at a lower cost than EPE can generate the power. EPE also seeks to sell power in the wholesale power market when it can earn a margin above the cost of the energy. Margins on off-system sales are credited to retail customers, thus lowering overall fuel costs. Additionally, in April 2023, EPE joined the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM"). Participation in the EIM allows EPE to purchase and sell power in a broader market on an intra-hour basis, which has provided more efficiency savings to customers.

Q35. CAN YOU BRIEFLY DESCRIBE THE EIM?

A. The EIM is a centralized, intra-hour energy-only market that seeks efficient dispatch of generation across the EIM footprint to serve real-time customer demand. The EIM looks to solve energy imbalances between forecasted demand and supply and actual real - time demand and supply. The EIM currently represents nearly 80% of the demand for electricity in the Western Interconnection.

Q36. HOW DOES THE EIM FUNCTION?

A. Prior to the operating hour, EIM participants submit forward looking energy schedules for each of their resources balanced against forecasted demand. Participants also submit accompanying bid prices for dispatchable resources signaling a willingness to increase or decrease output of those resources within the hour. In each hour, across the entire EIM footprint and using the principles of security constrained unit commitment and security constrained economic dispatch, imbalances are resolved at a fifteen-minute interval in the real-time pre-dispatch market, and then further refined at a five-minute interval in the real – time dispatch (RTD) market. This refinement ensures the latest changes to the status of the system are considered when solving imbalances. Resources are then provided with dispatch operating instructions every five minutes based off the respective RTD solution for that given interval.

Q37. WHAT IS IMBALANCE ENERGY?

A. Imbalance energy is the difference between forward hourly schedules and the actual materialized real-time values of load and generation. Imbalances occur for several reasons including demand forecast error, renewable generation intermittency, and unplanned events such as generator outages.

Q38. DOES THE EIM REPLACE BILATERAL OFF-SYSTEM SALES AND PURCHASES?

A. No. The EIM is intra-hour only and looks to optimize resources only after bilateral sales and purchases have been completed. The EIM considers the marginal cost of generation in dispatching, every fifteen and five minutes, the most cost-effective generation to meet the real-time load forecast.

Q39. HOW DID EPE RESOLVE IMBALANCES PRIOR TO EIM?

A. Prior to joining the EIM, EPE would solve intra-hour imbalances via dispatch of a subset of available generation.

Q40. WHAT BENEFITS DOES THE EIM PROVIDE TO PARTICIPANTS?

A. Since its inception in 2014, the EIM has provided over $6.2 billion in cumulative benefits. Approximately $1.6 billion of those estimates came in 2023 alone. The EIM also provides reliability benefits through increased system awareness and environmental benefits of greenhouse gas reductions by optimizing across its diverse market footprint. CAISO does not quantify reliability benefits.

Q41. SPECIFICALLY WHAT RELIABILITY BENEFITS DO EPE CUSTOMERS REALIZE AS A RESULT OF EPE JOINING THE EIM?

A. Participation in the EIM provides EPE access to intra-hour energy during unexpected contingencies, allowing the Company to mitigate generation costs or respond to unplanned system contingencies in the real-time energy market. Participating in the EIM mitigates the risk of diminished real-time supply options during emergency situations, as increased participation in the EIM means there is and will continue to be less liquidity in the real - time and intra-hour bilateral trade market outside the EIM. Participation in the EIM is particularly useful in the case of a need for emergency power due to a forced contingency. That power can be quickly acquired from the EIM; this ability to acquire power on an emergency basis was not available to EPE prior to joining the EIM.

Q42. DOES THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR OR EIM HAVE CONTROL OVER EPE TRANSMISSION FACILITIES?

A. No. The EIM only utilizes participants' unused and available transmission capacity that EPE has authorized as being available to the EIM. EPE determines on an hourly basis its generation and transmission availability to participate in the EIM.

Q43. HOW MUCH DID EPE REALIZE IN BENEFITS FROM PARTICIPATION IN THE EIM DURING THE TEST YEAR?

A. As reported by CAISO, EPE made approximately $17.6 million in benefits during the Test

Year based on its participation in the EIM, as shown in Exhibit VM-03. All benefits derived from EPE's participation in the EIM are passed on directly to EPE's customers.

Q44. DID EPE INCUR ANY EXPENSES RELATED TO ITS PARTICIPATION IN THE EIM DURING THE TEST YEAR, AND WERE THOSE EXPENSES REASONABLY AND PRUDENTLY INCURRED?

A. Yes. EPE incurred a total expense of $2.9 million for startups, shutdowns, and minimum load costs associated with market-driven resource commitments in the EIM. These costs are in essence additional O&M costs for its generation resources attributed to EPE participating in the EIM. EPE also calculated a cost of approximately $1 million to direct labor costs associated with its EIM participation, as well as approximately $900,000 in software costs. When the additional expenses are netted against the total $17.6 million benefits, the true net benefit of EPE participating in the EIM was approximately $12.7 million during the Test Year, as shown in Exhibit VM-03. Based on the benefits that EPE customers realized during the Test Year because of the Company's participation in the EIM, which significantly outweighed the expenses incurred as part of that participation, the EIM expenses are reasonable and prudent and should be included in EPE's cost of service.

B. Energy Management System Upgrade

Q45. ARE YOU SUPPORTING THE ENERGY MANAGEMENT SYSTEM ("EMS") UPGRADE ADDITION?

A. Yes.

Q46. CAN YOU GENERALLY DESCRIBE THE EMS?

A. The EMS acts as the central nervous system of EPE's bulk electric system due to its coordination of generation, transmission, and distribution assets in near real time. The e-terraplatform EMS is used by reliability coordinators such as the Electric Reliability Council of Texas, Florida Power & Light, British Columbia Hydro, and Southwest Power Pool, as well as by other utilities such as AVISTA, BPA, and Idaho Power.

Q47. DOES THE EMS SUPPORT EPE'S PARTICIPATION IN THE EIM?

A. Yes. The EMS was recently upgraded to support EPE's participation in the EIM.

Q48. WHAT IS THE COST OF THE EMS UPGRADE?

A. The total cost of the EMS upgrade project was approximately $7.3 million.

Q49. WHEN WAS THE EMS UPGRADE PLACED IN SERVICE?

A. The EMS upgrade was completed and placed into service for EPE customers in September 2024.

Q50. HOW IS THE EMS USED IN THE PROVISION OF ELECTRIC SERVICE TO EPE'S CUSTOMERS?

A. The EMS is necessary for the reliable operation of EPE's power grid and EPE's operation within the Western Interconnection. The EMS is designed to centrally monitor, analyze, optimize, simulate, and control EPE's generation, transmission, and distribution assets. The EMS allows for the coordination of electricity flows with EPE's neighboring utilities as well as generation control functions such as economic dispatch and automatic generation control, and it interfaces with system protection devices. The supervisory control and data acquisition components of the EMS include Data Acquisition, Data Processing, Inter - Control Center Communications Protocol, Supervisory Control, Real-time Calculations, Tagging, Alarming, and Load Shed and Restore. The network application functions include Network Topology Processor, State Estimator, Dispatcher Power Flow, Contingency Analysis, and Dispatcher Training Simulator, which are all necessary for reliable system operation. EPE custom software includes Interchange Scheduling, Energy Accounting, Alarm Processing Monitor, Multiple Breaker Rotational Load Shed, and transfer capability applications such as Southern New Mexico Import Capability and El Paso Import Capability.

Q51. WERE THE COSTS OF THE EMS UPGRADE NECESSARY AND REASONABLE?

A. Yes. The upgrade was necessary to communicate vital bulk electric system information in real time so that the Company could fully and capably participate in the EIM. Some of these specific integrations include: new applications that allow observation of renewables and battery storage operation and ensure that EPE's automatic generation control system can effectively monitor and control battery storage resources; an upgrade to Energy Analysis that allows for correct energy accounting and balance; revenue quality meter integration throughout the system including at generation stations; network infrastructure upgrades including cyber protection; hardware refreshes of equipment to ensure capability with adjacent devices and EIM; and the extension of end-of-life support windows that guaranteed continued technical support assistance. The costs associated with the EMS upgrade were reasonable, necessary and prudent.

Q52. HOW DOES THE EMS UPGRADE BENEFIT CUSTOMERS?

A In addition to maintaining the reliability of EPE's bulk electric system which ensures the continuous supply of electricity to customers, the upgrade allows for implementation of the EIM. The upgrade will effectively allow EPE to utilize renewable resources such as solar, wind, and battery storage in real time. This is essential due to the volatility of these resources. Wind production, for example, can be producing energy consistently and suddenly drop rapidly to no production at all. The EIM would need to respond to supplement the loss with real-time transactions at the lowest cost to EPE customers and dictate that to the EMS. Previously the EMS would not have the capability to respond as quickly due to the lack of integration. Battery control was another feature added to the EMS upgrade that was not included in previous "off the shelf" EMS software purchases. Due to the increasing demand for systemwide battery storage resources in the energy industry, the manufacturer was compelled to include new battery control enhancements, such as charge and discharge capabilities, as part of the EMS upgrade. This upgrade is designed to seamlessly integrate the operational controls for renewable and battery storage resources into the EMS and maximize customer benefits.

C. Newman Unit 3 Extension - Fuel and Purchase Power Analysis

Q53. DID ENERGY RESOURCES PERFORM AN ANALYSIS WITH REGARD TO UPGRADES THAT WERE MADE TO NEWMAN UNIT 3 DURING THE TEST YEAR.

A. Yes. Starting in June 2023, there was an outage at Newman Unit 3 that lasted for nine months. This outage was a combination of a forced outage resulting from multiple equipment failures, together with an outage that had been planned to begin on November 12, 2023. During the outage, there was worked performed on the unit that effectively extended the lives of the turbine and generator for an additional five years. EPE witness Rodriguez discusses these outages and the work that was done on the unit during those outages in more detail in his direct testimony. Energy Resources was asked to perform an analysis to determine the capacity deferment value of extending the service life of this 90 MW unit for an additional five years.

Q54. HOW WAS THIS ANALYSIS PERFORMED AND WHAT WERE THE RESULTS?

A. Energy Resources used the LCOE spreadsheet developed in the evaluation of the Newman Unit 6 resource in the 2021 Texas RFP to calculate a $/kW proxy price of building another gas generation resource similar to Newman Unit 6. The analysis determined that the benefit that EPE will realize given the upgrades to Newman Unit 3 that were made during the 2023-24 outage, would be approximately $10.6 million of deferred capital costs by extending the service life of the unit for an additional five years, as opposed to building a new gas-fired generation resource.

VI. Palo Verde

Q55. PLEASE DESCRIBE PVGS.

A. PVGS is a nuclear generating station, located on an approximately 4,000-acre site approximately 50 miles west of Phoenix, Arizona. The facility consists of three separate, virtually identical generating units, and a variety of common support facilities. The net design electrical ratings of the facilities are 1,333 MW for Unit 1; 1,336 MW for Unit 2; and 1,334 MW for Unit 3. EPE's share of the total PVGS design capacity is 633 MW. PVGS also has a switchyard that operates at 500 kilovolts. EPE witness Cary Harbor provides a detailed description of PVGS in his direct testimony.

Q56. PLEASE SUMMARIZE EPE'S COST OF SERVICE AND RATE BASE ADDITIONS REQUEST FOR PVGS.

A. EPE is requesting rate base capital additions of $134.2 million on a total Company basis for PVGS. EPE also is requesting $104.5 million in total unadjusted Company Test Year

Nonfuel O&M for PVGS, along with the adjustments that I summarize below.

Q57. ARE ANY ARIZONA PUBLIC SERVICE COMPANY ("APS") EMPLOYEES TESTIFYING ON EPE'S BEHALF IN THIS CASE?

A. Yes, EPE witness Harbor is an employee of APS, which operates PVGS, and he discusses in detail the PVGS O&M and capital additions, from the plant perspective, from January 1, 2021, through September 30, 2024.

Q58. WHAT CONTROL DOES EPE HAVE OVER PVGS?

A. EPE is a minority, non-operating owner of PVGS. However, as a co-owner, EPE exercises its ownership and oversight rights provided to the Company by the PVGS operating agreement. The Company's oversight activities are discussed later in my testimony.

A. Overview of Palo Verde

Q59. IS PVGS A RELIABLE AND ECONOMIC RESOURCE FOR THE COMPANY'S CUSTOMERS?

A. Yes. PVGS has long been a source of base load power at low fuel prices for EPE's customers. PVGS diversifies EPE's portfolio of generation resources and provides long - term security to customers.

Q60. HOW IS PVGS OWNED AND OPERATED?

A. The ownership of PVGS is divided among seven utilities ("Owners"). The ownership percentages for each of the Owners can be found below in Table VM-1.

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Table VM-1	
Participant/Owner	**Percentage Owned**
Arizona Public Service	29.10%
Salt River Project	20.40%
Southern California Edison Company	15.80%
Los Angeles Department of Water and Power	5.70%
Public Service Company of New Mexico	7.29%
El Paso Electric	15.80%
Southern California Public Power Authority	5.91%

APS operates PVGS pursuant to a contract among the Owners, entitled the Arizona Nuclear Power Project Participation (ANPP) Agreement, which became effective August 23, 1973. The most recent amendment to the ANPP Agreement was executed in April 2014. The agreement calls for several Owner committees: Administrative Committee, Engineering & Operations ("E&O") Committee, Audit Committee, Fuel Committee, Switchyard Committee, and Termination Funding Committee. EPE employees are on the Administrative, E&O, Termination Funding, Audit, Fuel, and Switchyard Committees. I serve as a member of the Administrative, E&O, and Fuel Committees.

B. PVGS Performance During the Test Year

Q61. DID PVGS OPERATED EFFICIENTLY DURING THE TEST YEAR?

A. Yes. For example, in 2023 and 2024, PVGS achieved a capacity factor of 91.42% and 93.65%, respectively. In comparison, the U.S. Energy Information Administration (EIA) reported that the United States nuclear fleet averaged a 93.1% capacity factor in 2023. It should be noted that PVGS achieved this capacity factor taking into consideration refueling outages, during which several large reliability projects were implemented. EPE is obligated in fuel reconciliation cases to provide testimony addressing the reasonableness of operation if Palo Verde's level of performance as measured by achieved capacity factor falls below 89.5% on a three-year rolling average, on a unit-by-unit basis. As set forth in EPE's fuel reconciliation testimony, Palo Verde Units 1 and 2 met this performance standard for the three-year period of 2021 through 2023, and Palo Verde Unit 3 was just slightly below that capacity factor.

APS and the Owners, through their oversight function, continue to work to improve performance at PVGS and will continue to incur costs related to the efforts to achieve expected performance.

C. Palo Verde Capital Monitoring and Approval Process of Capital Costs

Q62. HOW DOES EPE MONITOR PVGS CAPITAL ACTIVITIES AND COSTS?

A. EPE monitors Palo Verde capital activities and costs primarily through the PVGS E&O Committee's Capital Improvement Budget and Capital Project Approval Process ("Capital Budget Procedure"). EPE participated in the development of this procedure, which provides a process for all Owners to review, approve, and control PVGS capital improvement costs. The Owners must unanimously approve all capital improvements. A unanimous vote is likewise required for the capital budget each year. Once the budget is approved, APS can proceed with construction only on those projects for which E&O Committee approval has been received.

Q63. WHAT IS EPE'S REVIEW PROCESS FOR THE PALO VERDE CAPITAL BUDGET?

A. EPE reviews the annual Palo Verde capital budget as part of the overall budget package, to ensure that budget items and levels match the requirements determined necessary for safe and efficient operation by the E&O Committee. EPE analyzes the line items for consistency with activities from prior years and with ongoing repair, replacement, and improvement efforts. EPE regularly attends and participates in plant meetings to better understand and evaluate capital budget needs.

EPE reviews budget submittals to ensure that projects are identified and accounted for in the correct budget (capital versus O&M), they are in the correct budgetary category, and carryover work is accurately represented from one year to the next. EPE also reviews capital project justifications and scrutinizes individual projects to ensure the projected total costs do not exceed the capital improvement work authorization variance limits contained in the Capital Budget Procedure. Additionally, EPE reviews projected indirect PVGS capital improvement overhead and allocated costs.

Q64. ARE THERE FURTHER REVIEWS OF THE CAPITAL BUDGET BY PROJECT?

A. Yes. Capital budget approval signifies an Owner's agreement to allocate funds for the capital project for the budget year. Projects are presented individually to the E&O Committee throughout the year using work authorization packages that include business cases and financial analyses for the proposed projects. Non-regulatory projects above $500,000 must be approved by both the E&O and the executive level Administrative Committees. Except for emergent issues that must be addressed immediately, APS may not spend money or otherwise proceed with project implementation until the project has been reviewed and approved by the applicable Owner Committee(s). This process allows the Owners the opportunity to review and ask questions about proposed projects to help ensure that these expenditures serve customer interests.

Q65. DOES EPE COMPARE ACTUAL PVGS CAPITAL COSTS TO BUDGET AMOUNTS?

A. Yes. EPE monitors variance explanations for budgeted amounts monthly. This monthly analysis allows comparison of individual projects against budget and against the amount approved, in total, for each individual project. EPE can further investigate any material variances and communicate with APS and other Owners to address any concerns.

Q66. WHAT DO YOU CONCLUDE ABOUT THIS PROCESS FOR THE REVIEW AND APPROVAL OF CAPITAL EXPENDITURES?

A. The review and approval process for capital expenditures is crafted to verify that proposed projects undergo thorough examination and assessment to establish their necessity and reasonableness. Review and approval are required by PVGS management, and unanimous approval by the Owners is also required. The approval process ensures capital improvements at PVGS are consistent with the needs of all the Owners and in the best interest of their customers.

D. PVGS Capital Additions to Rate Base

Q67. WHAT AMOUNT OF PVGS CAPITAL ADDITIONS TO RATE BASE DOES EPE REQUEST?

A. The Company is seeking to include $134.2 million in PVGS total Company capital additions to rate base, which were placed in service during the period January 1, 2021, through September 30, 2024, the end of the current Test Year.

Q68. WHERE IS INFORMATION ABOUT THE CAPITAL PROJECTS THAT WERE ADDED AT PVGS FROM JANUARY 1, 2021, THROUGH SEPTEMBER 30, 2024?

A. There are three sources of this information. EPE witness Cynthia Prieto's capital additions exhibit lists Palo Verde plant additions during the period January 1, 2021, through September 30, 2024. Schedule H5.2a includes a list of all Palo Verde capitalized projects with actual costs of $100,000 or more (EPE share) that EPE requests be included in rate base. Lastly, the testimony of EPE witness Harbor describes PVGS major capital additions that support PVGS's philosophy to replace aging plant components from a plant wide perspective utilizing categorization specific to PVGS.

Q69. ARE THE PVGS CAPITAL EXPENDITURES INCLUDED IN EPE'S REQUEST REASONABLE AND NECESSARY?

A. Yes. The capital projects that resulted in these costs have undergone the budget and project review processes discussed above. EPE, as well as all the other Owners, have concurred that the projects and related costs are reasonable, necessary, and prudent for safe, reliable, cost-effective service to our customers.

E. PVGS O&M Expense

1. General Discussion

Q70. DOES EPE MONITOR AND REVIEW PVGS O&M COSTS?

A. Yes. EPE reviews the annual O&M budget, as part of the overall budget package, including budget assumptions. EPE reviews the package to ensure that the budget is reasonable based upon expected plant performance and the refueling and maintenance outage schedules, and consistent with the budgeted staffing levels and other operational needs (*e.g.,* loads, insurance premiums, and United States Nuclear Regulatory Commission fees). In addition to a total budget, APS provides separate refueling and maintenance outage budgets for EPE, and other Owners, to review and verify that the amounts and scope are both reasonable and consistent with planned outage dates. The reviews and questions submitted by other Owners on the proposed O&M budget are also reviewed and considered by EPE prior to EPE participating in the budget approval process. Unanimous approval of the O&M budget by the Owners is required under the ANPP Agreement.

2. Test Year Costs

Q71. WHAT AMOUNT OF PVGS O&M EXPENSE DID EPE INCLUDE IN THE TEST YEAR COST OF SERVICE?

A. EPE included the unadjusted Test Year costs in the amount of $104.5 million for nonfuel O&M expense. The PVGS O&M cost information is included in Schedule G-15 co-sponsored by EPE witness Steven A. Sierra. EPE witness Sierra also presents adjustments to Test Year O&M costs.

Q72. WHAT DOES THIS TEST YEAR AMOUNT REPRESENT?

A. This amount represents EPE's Test Year share of the costs to perform the day-to-day O&M activities on Units 1, 2, 3, common plant and water resources at PVGS.

Q73. ARE THE TEST YEAR EXPENDITURES REASONABLE?

A. Yes. These costs are reasonable and necessary to provide safe and reliable energy to customers and reflect unadjusted Test Year costs. Processes and procedures are in place that allow the Owners to closely scrutinize the O&M budget before it is adopted. The efficiency of a plant, measured by $/O&M per megawatt hour (MWh), can be affected by prudent spending on O&M as well as capital. As discussed in the testimony of EPE witness Harbor, the combination of higher capacity factors and mostly lower costs has put PVGS below the industry average on a cost-per-MWh basis.

Q74. HOW DOES EPE DETERMINE IF O&M COSTS ARE REASONABLE?

A. As described previously, EPE participates in the review and approval of the PVGS O&M budget. EPE monitors the PVGS O&M variance explanations and identifies issues throughout the year. EPE makes informal and formal recommendations for corrective actions, as necessary. Furthermore, EPE monitors public policy issues such as Arizona property taxes, operational issues affecting plant capacity factor enhancements, and maintenance efficiencies. These steps help ensure costs remain reasonable.

Q75. ARE O&M COSTS INCREASING AT PVGS?

A. Yes. As previously noted, the PVGS is located west of Phoenix, Arizona. That region has experienced significant growth in the last several years, to the point where it is becoming more and more difficult for PVGS to attract and retain talent. Most of the increase in O&M cost at PVGS is related to labor and labor-related overheads, including hourly and salary increases, as well as increases in headcount. Furthermore, there were increases in major chemical prices, material rebuilds, increased insurance costs, and corporate fees.

Q76. DOES APS PROVIDE EXPLANATIONS OF ANY PVGS O&M BUDGET VARIANCES?

A. Yes. APS and PVGS personnel provide monthly variance reports and explain variances at E&O Committee meetings. Where necessary, EPE and other Owners seek clarifications to make budget recommendations.

Q77. FOR ITS BASE RATE REQUEST, IS THE COMPANY PROPOSING ANY ADJUSTMENTS TO THE TEST YEAR PVGS O&M EXPENSES?

A. Yes. Please see EPE witness Sierra's direct testimony for the adjustments to Test Year O&M expenses.

VII. Summary and Conclusions

Q78. PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS.

A. The value of capacity that EPE proposes to be imputed to the Macho Springs and Newman solar PPAs is in accordance with the settlement and order in Docket No. 46831 and should thus be approved by the Commission. The Commission should also approve the inclusion of the capacity charges for the Buena Vista I BESS. The Buena Vista 1 BESS capacity charge is well-below market, and the resource has been serving Texas customers since July of 2023.

The Commission should approve EPE's request to include in rate base 100% of the capital investment made in Newman Unit 6, which has been exclusively serving Texas customers since December 27, 2023. The portion of Newman Unit 6 that would have served EPE's New Mexico customers was rejected by the NMPRC and subsequently was selected through a competitive solicitation process as part of the least-cost portfolio of resources to meet EPE's growing capacity needs. I also provided an analysis indicating the economics of the costs of accelerating the construction project for Newman Unit 6 as opposed to the cost of purchasing replacement capacity and energy on the market. I also described an analysis performed by my team to determine the value of certain upgrades made during the test year at EPE's Newman Unit 3.

The Commission should also approve the costs incurred during the Test Year related to the Company's participation in the EIM market given the significant benefits such participation has obtained for EPE's customers. Further, the Commission should approve the costs incurred by the Company for the recent upgrade of its EMS in order to support EPE's participation in the EIM. Such costs were reasonable and necessary and have resulted in significant benefits to EPE customers.

Finally, the Commission should approve the inclusion of the capital additions placed in service at Palo Verde from January 1, 2021, through September 30, 2024, in EPE's rate base, and should also approve the inclusion of the Palo Verde Test Year O&M expenses in the Company's cost of service, because those capital additions and O&M costs were reasonable, necessary and prudent.

Q79. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED BY V. MARTINEZ

Schedule	Description	Sponsorship	In Rate case package
C-6.8	ALLOCATION OF UNASSIGNED BALANCE	Co-Sponsor	Yes
C-6.9	NUCLEAR FUEL INVENTORY POLICY	Sponsor	Yes
E-2.1	FOSSIL FUEL INVENTORY POLICIES	Sponsor	Yes
E-2.2	FOSSIL FUEL INVENTORY EVALUATION	Sponsor	Yes
E-2.3	FOSSIL FUEL INVENTORIES	Co-Sponsor	Yes
E-2.4	FOSSIL FUEL INVENTORY LEVELS	Co-Sponsor	Yes
E-2.5	FOSSIL FUEL INVENTORY VALUES	Co-Sponsor	Yes
E-3.1	FUEL OIL BURNS	Co-Sponsor	Yes
E-3.2	NATURAL GAS SUPPLY DISRUPTIONS	Sponsor	Yes
E-3.3	COAL OR LIGNITE SUPPLY DISRUPTIONS	Sponsor	Yes
H-1	SUMMARY OF TEST YEAR PRODUCTION O&M EXPENSES (NUCLEAR & FOSSIL)	Co-Sponsor	Yes
H-1.1	NUCLEAR COMPANY-WIDE O&M EXPENSES SUMMARY	Co-Sponsor	Yes
H-1.1a	NUCLEAR PLANT O&M SUMMARY	Co-Sponsor	Yes
H-1.1a1	NUCLEAR UNIT O&M SUMMARY	Co-Sponsor	Yes
H-5.2a	NUCLEAR CAPITAL COSTS PROJECTS	Co-Sponsor	Yes
H-5.3a	NUCLEAR CAPITAL EXPENDITURES (HISTORICAL, PRESENT, PROJECTED)	Co-Sponsor	Yes
H-6.1a	NUCLEAR UNIT OUTAGE HISTORY	Co-Sponsor	Yes
H-6.1b	NUCLEAR UNIT OUTAGE DATA	Co-Sponsor	Yes
H-6.1c	NUCLEAR UNIT OUTAGE PLANNING	Co-Sponsor	Yes
H-6.3a	NUCLEAR UNIT INCREMENTAL OUTAGE COSTS	Co-Sponsor	Yes
H-12.4a	FIRM PURCHASED POWER (NET MWh)	Sponsor	Yes
H-12.4b	FIRM PURCHASED POWER ENERGY COSTS	Sponsor	Yes
H-12.4c	FIRM PURCHASED POWER FIXED COSTS	Sponsor	Yes
H-12.4d	FIRM PURCHASED POWER ENERGY COSTS PER MWh	Sponsor	Yes

SCHEDULES SPONSORED BY V. MARTINEZ

Schedule	Description	Sponsorship	In Rate case package
H-12.4e	NON-FIRM PURCHASED POWER (Net MWh)	Sponsor	Yes
H-12.4f	NON-FIRM PURCHASED POWER ENERGY COSTS	Sponsor	Yes
H-12.4g	NON-FIRM PURCHASED POWER ENERGY COSTS PER MWh	Sponsor	Yes
H-12.5b	OFF SYSTEM SALES - ECONOMY AND FIRM (NET MWh)	Sponsor	Yes
H-12.5c	OFF SYSTEM SALES REVENUE (ENERGY CHARGE COMPONENT)	Sponsor	Yes
H-12.5d	OFF SYSTEM SALES REVENUE (FIXED CHARGE COMPONENT)	Sponsor	Yes
H-12.5e	OFF SYSTEM SALES REVENUE (ENERGY CHARGE PER KWh)	Sponsor	Yes
I-1.3	FOSSIL FUEL PURCHASED	Sponsor	Yes
I-1.4	NON-RECURRING FUEL AND PURCHASED POWER EXPENSES	Sponsor	Yes
I-2	FUEL AND PURCHASED POWER PROCUREMENT PRACTICES	Sponsor	Yes
I-3	FUEL AND PURCHASED POWER COMMITTEES	Sponsor	Yes
I-4	FUEL AND FUEL-RELATED CONTRACTS	Sponsor	Yes
I-7	NATURAL GAS STORAGE DESCRIPTION	Sponsor	Yes
I-8	FUEL PROPERTIES	Sponsor	Yes
I-9	EMPLOYEE ORGANIZATIONAL CHARTS	Sponsor	Yes
I-10	EMPLOYEE ETHICS	Sponsor	Yes
I-11	FUEL AND PURCHASED POWER ASSUMPTIONS NARRATIVE	Sponsor	Yes
I-12	FOSSIL FUEL MIX	Sponsor	Yes
I-13	ETHICS - RELATIONSHIP WITH FUEL SUPPLIER	Sponsor	Yes
I-15	FUEL CONTRACT ANALYSES - RECONCILIATION PERIOD	Sponsor	Yes
I-16	RECONCILABLE FUEL COSTS (NA-fuel rec)	Co-Sponsor	Yes

SCHEDULES SPONSORED BY V. MARTINEZ

Schedule	Description	Sponsorship	In Rate case package
I-16.1	FOSSIL FUEL MIX (BURNED) (NA-fuel rec)	Co-Sponsor	Yes
I-16.2	FOSSIL FUEL MIX (PURCHASED) (NA-fuel rec)	Co-Sponsor	Yes
I-16.3	COMPETITIVE SPOT FOSSIL FUEL PURCHASES (NA-fuel rec)	Co-Sponsor	Yes
I-16.4	OTHER SPOT FOSSIL FUEL PURCHASES	Sponsor	Yes
I-17.1	COAL COST BREAKDOWN	Co-Sponsor	Yes
I-17.2	LIGNITE COST BREAKDOWN	Sponsor	Yes
I-17.3	COAL COST DESCRIPTION	Sponsor	Yes
I-18	COAL AND LIGNITE SUPPLIER LOCATIONS	Sponsor	Yes
I-19.1	RAIL HAUL DISTANCE	Sponsor	Yes
I-19.2	UNIT TRAINS	Sponsor	Yes
I-19.3	CYCLE TIME	Sponsor	Yes
I-19.4	RAIL CARS	Sponsor	Yes
I-19.5	RAIL CAR LEASES	Sponsor	Yes
I-19.6	RAIL CAR MAINTENANCE	Sponsor	Yes
19.7	RAIL CAR REPAIRS	Sponsor	Yes
I-21	FUEL MANAGEMENT	Sponsor	Yes
O-1.5	SYSTEM INFORMATION	Sponsor	Yes

El Paso Electric Company

100 N. Stanton St.
Post Office Box 982
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MEMORANDUM

TO: David Rodriguez
FROM: Victor Martinez
DATE: February 6, 2023
SUBJECT: Newman 6 Delay – Fuel and Purchase Power Cost Impact Study

Summary

On February 5, 2023, El Paso Electric's ("EPE") Resource Planning Department ("RP") received a request to perform a Fuel and Purchased Power ("FPP") cost impact study for delaying Newman 6 ("NM6"), which is scheduled to commence operation on June 21, 2023, at the beginning of the peak summer months. NM6 is a combustion turbine unit carrying a nameplate capacity of 228 MW.

The General Contractor ("GC") for the NM6 project contacted EPE with a preliminary Change Order ("CO") for approximately $11.3MM. The completion of NM6 has been delayed due to late equipment deliveries caused by supply chain disruptions, impacts from COVID-19 and extreme weather; and technical issues experienced throughout the project. The CO assumes continuing with the normal course and pool of resources but extending the Commercial Operation Date ("COD") to September 11, 2023.

An alternative option to accelerate the project entails continuing to push completion of the NM6 project to as close as the original contract completion date as possible. However, this will require addition manpower, overtime, and adding a second shift at night (six days per week, ten hours per day for twelve weeks) beginning February 6, 2023, through April 29, 2023. The total Rough Order of Magnitude ("ROM") for acceleration is estimated at $7.2MM; the delay and impact costs incurred by the GC is estimated to be an additional $4.4MM and $2.3MM, respectively; for a grand total of $13.9MM. Refer to Exhibit D for details of the acceleration ROM, delays, and impacts.

Sensitivity Analysis

To quantify the FPP cost impact of delaying NM6, the RP team ran a series of sensitivities using the production cost model called Aurora.

The base case and the sensitivities used in this study assume the 2023 FPP Budget with Opportunity Sales, updated with gas and Palo Verde Market prices using the price curve dated January 18, 2023.

The table below summarizes a few other assumptions used in the study, followed with a detailed description of each.

NEWMAN 6	Base Case	Sensitivity 1	Sensitivity 2	Sensitivity 3
COD	June 21, 2023	July 21, 2023	August 21, 2023	September 11, 2023
Heavy load forward market purchase	none	June 21 through July 20, 2023	June 21 through August 20, 2023	June 21 through September 10, 2023

The base case assumes the original COD of June 21, 2023.

The first sensitivity assumes delaying NM6 by one month, starting on July 21, 2023. To compare "apples" to "apples" and keep the same level of reliability, a heavy load forward market purchase for 210 MW was forced-in beginning June 21, 2023, through July 20, 2023. The 210 MW heavy load market purchase is equivalent to the capacity that Newman 6 would have contributed based on its Effective Load Carrying Capability ("ELCC")[1].

The second sensitivity assumes delaying NM6 by two months, starting on August 21, 2023, with a forced-in heavy load forward market purchase of 210 MW beginning June 21, 2023, through August 20, 2023. The third sensitivity assumes the CO option which delays NM6 by almost three months to September 11, 2023. A heavy load forward market purchase of 210 MW was forced in beginning June 21, 2023, through August 31, 2023. Since load demand starts to decrease in September, RP assumed heavy load forward market purchases during the first ten days was not necessary.

The results show that delaying NM6 by one and two months - to July 21, 2023, and August 21, 2023 - increases FPP costs by $8.6MM and $19.6MM, respectively. Delaying NM6 to the proposed Change Order date of September 11, 2023, increases FPP costs by $24.8MM. Exhibit A reflects the FPP cost by month in comparison to the Base Case.

Conclusion

Even though the accelerated ROM option requires addition manpower, overtime, and adding a second shift for twelve weeks, it will cost less than the CO option, $13.9MM compared to $36.1MM ($11.3MM plus increased FPP costs of $24.8MM) as reflected on Exhibit B. The CO option, which assumes extending the COD to September 11, 2023, is so much higher because of the heavy load purchase power required, during the peak summer period, to maintain reliability. The market price for heavy load purchase power

[1] ELCC is a capacity credit towards peak for each generation resource type, including gas resources. It is expressed as a percentage of the generator's nameplate rating and is determined using the Unforced Capacity method which deducts for forced outage rate from the unit capacity.

increases quite significantly from May to June, July, August, and September as reflected on Exhibit C.

The accelerated ROM option assumes completion of the NM6 project to as close as the original contract date of June 21, 2023. There is a possibility of the project being delayed because the schedule to complete NM6 is highly contingent upon EPE's responsibilities and on-site support during both the day and night shifts from Sargent and Lundy's for electrical design and from Mitsubishi for start-up and commissioning resources. However, even if the completion date for the project is extended another month to July 21, 2023, and assuming a third (one month equivalent) of the $13.9MM ROM estimated costs due to acceleration, delays, and impact, is added, it will still cost less than the CO option, $27.1MM compared to $36.1MM as reflected on Exhibit B.

Furthermore, if EPE decides to proceed with the CO option and the COD of September 11, 2023, is not met, such delay will result in additional FPP costs and potential additional impact and delay costs. This is on top of the $36.1MM referenced on Exhibit B. The longer the delay, the higher the costs.

Given these findings, Resource Planning recommends the alternative option to accelerate the project and accept the ROM for a grand total of $13.9MM.

EXHIBIT A
Newman 6 - Fuel and Purchase Power Cost Comparison

Newman 6 Sensitivity Analysis
FPP Comparison Analysis by Month

		2023 FPP Difference versus Base Case		
COD >>>	Base Case: June 21, 2023	Sensitivity 1: July 21, 2023	Sensitivity 2: August 21, 2023	Sensitivity 3: September 11, 2023
Jan-23	$39,510,149	$0	$0	$0
Feb-23	$21,976,686	$0	$0	$0
Mar-23	$12,959,016	$0	$0	$0
Apr-23	$11,420,949	$0	$0	$0
May-23	$12,640,219	$0	$0	$0
Jun-23	$17,051,359	$1,769,514	$1,769,514	$1,769,514
Jul-23	$20,288,778	$6,793,265	$10,143,213	$10,143,213
Aug-23	$20,665,197	$0	$7,679,681	$12,609,082
Sep-23	$20,065,428	$0	$0	$300,106
Oct-23	$15,869,560	$0	$0	$0
Nov-23	$16,136,753	$0	$0	$0
Dec-23	$20,047,084	$0	$0	$0
Total	**$228,631,178**	**$8,562,778**	**$19,592,407**	**$24,821,914**

Total FPP	**$237,193,956**	**$248,223,585**	**$253,453,092**

EXHIBIT B
Newman 6 - Cost Impact Analysis

Newman 6
Cost Impact Analysis

		Total Cost Impact $MM			
		Base Case: June 21, 2023	Sensitivity 1: July 21, 2023	Sensitivity 2: August 21, 2023	Sensitivity 3: September 11, 2023
1	Total FPP Cost Difference versus Base Case $MM	$0.0	$8.6	$19.6	$24.8
2	Change Order ("CO") Estimate $MM COD September 11, 2023				$11.3
3	Total Expense - CO Option = Sum Lines (1 & 2)				$36.1
4	Total Rough Order of Magnitude ("ROM") Estimate $MM COD - close to original date (late June 2023)	$13.9	$13.9		
5	Additional Costs [(a)]	$0.0	$4.6		
6	Total Rough Order of Magnitude ("ROM") Estimate $MM Adjusted based on new start date = Sum Lines (4 & 5)	$13.9	$18.5		
7	Total Expense - ROM Option = Sum Lines (1 & 6)	$13.9	$27.1		

[(a)] Sensitivity 1 ssumes additional costs for delays and other costs, which is equivalent to four weeks (one month) = ($13.9MM / 12 Weeks) * 4 Weeks = $4.6MM.

EXHIBIT C
Heavy Load Forward Market Purchase Prices

EL PASO ELECTRIC COMPANY
BLENDED PURCHASES POWER PRICE FORECAST

	Heavy Load, 6x16 Prices			
			PV Forward Monthly Prices $/MWH	% Change versus May
2023	Jan	$	150.08	
	Feb	$	107.48	
	Mar	$	45.00	
	Apr	$	36.36	
	May	$	32.42	
	Jun	$	81.02	150%
	Jul	$	165.17	409%
	Aug	$	184.45	469%
	Sep	$	133.21	311%
	Oct	$	62.69	
	Nov	$	59.46	
	Dec	$	79.67	

El Paso Electric – EPE Newman 6 Project

Delays, Impacts, and Acceleration ROM

The following tables provide a high-level summary of the costs associated with the request to Accelerate the project schedule (Table 1) as well as delays and impacts incurred by Casey due to EPE Caused Delays (Table 2) to achieve as close to the original contract completion date as possible.

The information below is at a high level and based on adding additional manpower, overtime, and a night shift starting February 6, 2023 through April 29, 2023. The First Fire date is highly contingent on Article 2.10 "EPE Responsibilities", on-site electrical design support from Sargent and Lundy to support both shifts, and additional Mitsubishi start up and commissioning resources on-site to support both shifts.

"SCHEDULE ACCELERATION ROM (6 DAYS + NIGHT SHIFT)"

Assumptions:

- 12-week nightshift 6 days per week 10-hours per day
- Based on the following target crew size:
  - Electrical: 35
  - Piping: 15
  - Multi-Craft / Rigging: 5
  - Warehouse: 5

CATEGORY	ROM AMOUNT	DESCRIPTION
Direct Hire		
Productivity Impact/Inefficiency	$2,196,162	Includes labor efficiency/productivity is impacted from the following items: extended OT fatigue, trade stacking due to compression of schedule, and nightshi inefficiency and turnover impact from dayshift to nightshift for those activities anticipated to be impacted.
Overtime Differential	$1,999,112	OT differential associated with 6 day/wk schedule and shift work.
Indirect Labor & Expenses	$1,140,638	Indirect staff and field support labor and expenses in support of the schedule acceleration including nightshift.
Craft Support Labor	$294,420	Additional orientation for added manpower and warehouse and forklift support labor to support accelerated schedule and increased manpower.
Construction Equipment (Casey Owned and 3rd Party)	$270,120	Additional and excessive operating hours for construction equipment to support the schedule acceleration.
Subcontract – Electrical, Insulation and Scaffold support	$445,625	Subcontractors' acceleration costs for additional manpower, extended OT fatigue, hours, trade stacking due to compression of schedule, and nightshift inefficiency and turnover impact from dayshift to nightshift, including additional scaffolding support.
Start-Up and Commissioning	$839,996	Additional support needed from 3rd Party for Piping Flushing activities due to activity stacking caused by schedule compression. Additional SU&C support on nights for hot commissioning.
TOTAL	**$7,186,073**	The Acceleration ROM requested by EPE does not include all costs incurred or related to delay as previously communicated by Contractor to EPE (see Table 2).

Table 1: Acceleration Rough Order of Magnitude

As previously communicated to EPE and in addition to the ROM for Acceleration, the project has experienced EPE caused impacts, including delayed engineering, detail design, supply of EPE provided materials, and the generator water discovery.

EXHIBIT D
Newman 6 – Delays, Impacts and Acceleration ROM
Page 2 of 2

"DELAYS AND IMPACTS IN ADDITION TO ACCELERATION ROM"

CATEGORY	ROM INCURRED COST	ROM DELAY COST
Staff and Craft Support Labor	$266,122	$2,203,407
Site Facilities		$72,317
Construction Equipment (incl. Fuel, Oil, Maintenance)	$101,410	$418,517
Start-Up and Commissioning Labor	$785,408	$370,188
Direct Manhour Labor Inefficiency	$535,550	$1,201,170
Direct Manhour Acceleration Costs (Cinco de Mayo)	$374,796	
Subcontractors		$110,362
Generator Water - Mitsubishi Support Labor and Materials	$235,253	Incl. Above
TOTAL	**$2,298,539**	**$4,375,961**

Table 1: Impacts and Delays in Addition to Acceleration ROM

The total Rough Order of Magnitude for Acceleration, Delays, and Impacts is $13,860,573.

EL PASO ELECTRIC COMPANY
TEST YEAR (TY) EIM BENEFITS SUMMARY
OCTOBER 23 - SEPTEMBER 24

Positive is payment to EPE / Negative is cost to EPE

Month	Report	Main Settlements	Admin	Penalty	Sub-Allocation	Counter Factual	EIM Dispatch	Net Benefits as Reported by CAISO
Oct-23	T+11M	$ 4,657,879	$ (34,128)	$ 2,610	$ (70,696)	$ (245,321)	$ (1,462,094)	$ 2,848,251
Nov-23	T+11M	$ 717,172	$ (21,441)	$ 19,393	$ 6,800	$ (56,859)	$ (233,023)	$ 432,043
Dec-23	T+70b	$ 1,218,192	$ (28,372)	$ (825)	$ (6,697)	$ (218,632)	$ (184,839)	$ 778,826
Jan-24	T+70b	$ 4,516,764	$ (26,482)	$ 14,202	$ (3,498)	$ (172,418)	$ (1,591,658)	$ 2,736,911
Feb-24	T+70b	$ 3,064,319	$ (26,767)	$ 5,429	$ (19,559)	$ (230,869)	$ (895,023)	$ 1,897,531
Mar-24	T+70b	$ 1,390,683	$ (19,295)	$ 8,248	$ 4,337	$ (12,036)	$ (208,722)	$ 1,163,215
Apr-24	T+70b	$ 1,184,510	$ (21,379)	$ 7,641	$ (21,846)	$ 30,346	$ (117,419)	$ 1,061,853
May-24	T+70b	$ 570,694	$ (20,623)	$ 2,645	$ (7,397)	$ 155,840	$ (51,173)	$ 649,985
Jun-24	T+70b	$ 1,212,045	$ (26,739)	$ 7,125	$ (2,825)	$ 76,047	$ (441,527)	$ 824,126
Jul-24	T+70b	$ 2,821,702	$ (31,280)	$ 4,167	$ (15,892)	$ 83,752	$ (640,843)	$ 2,221,605
Aug-24	T+9b	$ 1,814,244	$ (31,351)	$ 6,723	$ (6,057)	$ 47,087	$ (435,179)	$ 1,395,466
Sep-24	T+9b	$ 1,983,543	$ (26,981)	$ 6,312	$ (8,834)	$ 18,630	$ (377,685)	$ 1,594,984
Total		$ 25,151,748.20	$ (314,837.68)	$ 83,667.52	$ (152,163.44)	$ (524,434.42)	$ (6,639,186.00)	$ 17,604,794

Total Net Benefits to Customers During TY:	**$ 17,604,794**
Market Unit Start/Run Costs During TY:	$ (2,927,233)
EIM Labor Costs During TY:	$ (1,048,211)
EIM Software Costs During TY:	$ (901,173)
True Net Benefits of EIM During TY:	**$ 12,728,177**

DOCKET NO. 57568

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

DAVID RODRIGUEZ

FOR

EL PASO ELECTRIC COMPANY

JANUARY 2025

EXECUTIVE SUMMARY

David Rodriguez is the Vice President-Energy Supply for El Paso Electric Company ("EPE" or "Company"). He is responsible for the Company's local and remote power generation and its power marketing activities, which include power plant operations and maintenance, new plant construction, oversight of EPE's interest in its remote generation Palo Verde Generating Station ("Palo Verde"), power purchases and sales, and gas purchases.

Mr. Rodriguez describes EPE's generation fleet and supports the recovery of the costs of new investments in the fleet and of the costs to operate and maintain it. EPE's generation fleet consists of its local units and the remote generation at Palo Verde. EPE witness Cary Harbor describes Palo Verde costs and operations, and EPE witness Victor Martinez addresses EPE's rate requests related to Palo Verde.

Mr. Rodriguez addresses the capital additions to EPE's local generation fleet, including a new power generating unit at the Newman Power Station (Newman Unit 6), that the Company placed in service from January 1, 2021, through September 30, 2024, along with two known and measurable post-Test Year adjustments resulting in a decrease in rate base. These capital additions were reasonable and are used and useful to EPE in providing service to its customers.

Additionally, Mr. Rodriguez addresses the operations and maintenance ("O&M") expenses and practices that EPE employs to manage its local generation fleet, together with the level of O&M expenses that should be included in rates.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Rodriguez, and my business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company") as Vice President - Energy Supply.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I earned a Bachelor of Arts degree in Management in 2007 and a Master of Business Administration with a concentration in Finance in 2010, both from the University of Texas at El Paso. I have been employed at EPE for over 20 years, where I have held positions as a Power Plant Operator, Business Analyst, Manager of Support Services, Director of Support Services, Senior Director of Support Services and Supply Chain Management, Senior Director of Power Generation, Vice President of Power Generation, and most recently, Vice President of Energy Supply.

Q4. PLEASE DESCRIBE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS VICE PRESIDENT OF ENERGY SUPPLY FOR EPE.

A. My principal areas of responsibility are the fiscal and operational oversight of the Company's Power Generation and Power Marketing functions. Regarding Power Generation, my responsibilities include engineering, asset management, plant operation and maintenance, turbine and generator outages, new generation projects, and remote oversight of Palo Verde Generating Station ("Palo Verde" or "PVGS"), a nuclear power plant in Arizona that EPE owns in part. Regarding Power Marketing, my responsibilities include real-time, day-ahead, and long-term power and gas procurement, as well as overseeing the Company's participation in the Energy Imbalance Market ("EIM") operated by the California Independent System Operator ("CAISO").

Q5. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE A REGULATORY BODY?

A. Yes, I have submitted testimony to the Public Utility Commission of Texas ("PUCT" or Commission) and to the New Mexico Public Regulation Commission.

II. Purpose of Testimony

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe EPE's local generation fleet and to support recovery of the costs of new investments in that fleet and of the costs to operate and maintain it. EPE's generation fleet consists of its local gas-fired units, which I discuss below in Section III.

I address the status of the Company's generating units that are included in the Retiring Plant Rider and the current status of those units' planned retirements. I also present the operations and maintenance ("O&M") costs incurred during the Test Year for the Company's Rio Grande Unit 6 that EPE is requesting to recover through the Retiring Plant Rider. Rio Grande Unit 6 provided valuable service to EPE's Texas customers during the Test Year but has been out of EPE's rate base since 2016.

My testimony discusses the capital additions to EPE's local generation fleet, including Newman Unit 6, the new generating unit EPE placed in service at its Newman Power Station on December 27, 2023. A portion of the capital investment in this power generation facility is currently being recovered in Texas through a Generation Cost Recovery Rider ("GCRR"). In this filing EPE seeks approval to recover 100% of its total capital investment in Newman Unit 6 given that the unit has been exclusively used to serve Texas customers. EPE witnesses George Novela and Victor Martinez explain this request in more detail in their respective direct testimonies.

I also address the reasonableness and prudence of the costs of other capital additions and improvements for the local generation fleet made from January 1, 2021 through September 30, 2024, which covers the period that starts with the first month after the test - year end in EPE's last base rate proceeding, Docket No. 52195, through the end of the Test Year in this case, and which also includes two minor known and measurable post - Test Year adjustments that result in a decrease in total rate base.

In addition, I address the O&M practices that EPE employs to manage its local generation fleet and the related expenses, together with the level of reasonable and necessary Test Year O&M expenses for EPE's local generation that should be included in rates.

I discuss total Company generation fleet capital investments and operating costs in my testimony. EPE witness Adrian Hernandez discusses the allocation of the total Company costs to the Texas jurisdiction in his direct testimony.

Q7. WHAT DOES YOUR TESTIMONY DEMONSTRATE?

A. My testimony demonstrates that the capital additions to EPE's local generation fleet placed into service from January 1, 2021, through the September 30, 2024, Test Year end were prudent and reasonable and are used and useful in providing safe, reliable, and efficient power to meet EPE customers' needs.

I also demonstrate that EPE maintains effective cost controls at its local generating facilities. The O&M practices EPE employs to manage its local generation fleet are prudent and reasonable, and the Test Year O&M costs, as adjusted, are reasonable and necessary and should be included in rates.

Q8. WHAT RATE CASE SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. The schedules that I sponsor, or co-sponsor, are listed in Exhibit DR-1.

Q9. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

III. EPE's Generating Facilities

Q10. WHAT ARE EPE'S GENERATING FACILITIES?

A. EPE meets the bulk of its customers' electrical requirements with power produced at its generating stations, which are fueled by a mix of natural gas, uranium, and renewable resources. Table DR-01 identifies EPE's generating stations as of the September 30, 2024, Test Year end. The table also reflects the fuel types and net peak capacities of these resources.

Table DR-1

Generating Station	Net Peak Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	Duty
Palo Verde (Units 1, 2, and 3)[1]	622	Uranium	N/A	Base load
Rio Grande (Units 6, 7, 8, 9)	313	Natural Gas	N/A	Peaking and Load-following
Newman (Units 1, 2, 3, 4, 5, and 6)	902	Natural Gas	N/A	Peaking and Load-following; for Unit 5, load following and base load in combined cycle mode
Copper (Unit 1)	49	Natural Gas	N/A	Peaking
MPS (Units 1, 2, 3, and 4)	352	Natural Gas	Diesel	Peaking and load-following
Macho Springs Solar, LLC	50	Solar	N/A	Purchase Power Agreement, System Resource
Community Solar Facility[2]	3	Solar	N/A	Dedicated Facility for Customers in the Community Solar Program
Newman Solar	10	Solar	N/A	Purchased Power/Community Solar
Buena Vista Energy Center, LLC	120/50	Solar/Battery Storage	N/A	Purchase Power Agreement, System Resource
Total	2,421			

EPE also owns several small solar facilities with a combined capacity of approximately 1 megawatt ("MW").

The Newman and Copper Power Stations are located in EPE's Texas service area within the City of El Paso, Texas. The Rio Grande Power Station is located in EPE's southern New Mexico service area within the City of Sunland Park, adjacent to the City of El Paso. The Montana Power Station ("MPS") is located in EPE's Texas service territory just east of the City of El Paso in unincorporated El Paso County. The Montana, Copper, Newman, and Rio Grande Power Stations are considered EPE's local generation. Exhibit DR-2 is a map depicting the location of EPE's generation.

[1] The 622 MW Palo Verde is the total capacity owned by EPE including approximately 40 MW from Unit 3 that are not serving either Texas or New Mexico.

[2] Customer Dedicated Resources, the costs of which are not included in base rates.

Palo Verde, which is located in Arizona, is considered EPE's remote generation. EPE witness Carey Harbor addresses the costs and operations of Palo Verde, and EPE witness Victor Martinez addresses EPE's rate requests related to those costs and operations.

Q11. ARE ALL OF THE GENERATING FACILITIES INCLUDED IN THE ABOVE TABLE DR-1 AVAILABLE TO SERVE TEXAS LOAD?

A. Yes. Except for Community Solar, Newman Solar, Newman Unit 6, and Palo Verde Unit 3, all the resources included in the table are system resources that also serve New Mexico customers. The New Mexico Public Regulation Commission rejected certification of Newman Unit 6. As a result, that portion of Newman Unit 6 that would have otherwise served New Mexico retail load has been serving and will continue to serve EPE's growing Texas load.

A. Local Unit Operation and Performance

Q12. PLEASE BRIEFLY DESCRIBE THE TYPICAL OPERATION OF EPE'S LOCAL GENERATION.

A. Generally, EPE's local units are used to follow load and compensate for the variable output of renewable resources, to provide grid stability, and to serve EPE's load obligations. For the most part, each of the local units can be used interchangeably to satisfy these functions. EPE's load demands are such that, under normal conditions, the older conventional steam generating units (Newman 1, 2 and 3, Rio Grande 7 and 8) are typically backed down to minimum loads for the low load hours during off-peak periods and allowed to be economically dispatched during the higher load periods of the daytime peak periods, particularly during the summer. Newman Unit 6 is equipped to handle EPE's peak summer demands, and its ability to rapidly start up and shut down helps in managing the fluctuations of intermittent Company- and customer-owned renewable energy resources that are growing in magnitude. Rio Grande Unit 9 and the MPS units are designed and are routinely cycled to meet the varying load demands or to displace less efficient generation. Rio Grande Unit 6, which has not been included in EPE's rate base since 2016, was placed into Inactive Reserve status during 2019 and 2020 but came out of inactive reserve in June

2021.[3] In January 2022 the unit went back into inactive reserve status; however, Rio Grande Unit 6 was placed back into active status on March 5, 2022. Since then, it has remained available for dispatch, particularly to support peak demand as needed.

Q13. ARE ANY OF EPE'S LOCAL POWER GENERATING FACILITIES COMBINED CYCLE UNITS?

A. Yes. Newman Units 4 and 5 are two-on-one combined cycle units, each consisting of two gas turbines and one steam turbine. Newman Unit 4 consists of Unit 4-GT1, Unit 4-GT2 and Unit 4 Steam Turbine. Newman Unit 5 consists of Unit 5-GT3, Unit 5-GT4 and Unit 5 Steam Turbine. A combined cycle power generating facility uses both gas-fired combustion turbines (GT1 and GT2 in Unit 4, and GT3 and GT4 in Unit 5) and a steam turbine, together to produce additional electricity from the same fuel source. The energy in the exhaust heat from the combustion turbines is converted to thermal energy via a Heat Recovery Steam Generator and routed to the nearby steam turbine, which generates additional power. The combustion turbines can be operated independently from the steam turbines.

B. Retiring Plant Rider Status and Requested Addition

Q14. ARE THE GENERATION UNITS THAT ARE CURRENTLY INCLUDED IN THE RETIRING PLANT RIDER (NEWMAN UNITS 1 AND 2 AND RIO GRANDE UNIT 7) CONTINUING TO PROVIDE ELECTRIC SERVICE TO EPE'S RATEPAYERS?

A. Yes, they are. As I just explained, Newman Units 1 and 2 and Rio Grande Unit 7 continue to provide service to EPE's customers.

Q15. HAS EPE DETERMINED ON WHAT DATES NEWMAN UNITS 1 AND 2 AND RIO GRANDE UNIT 7 WILL BE RETIRED?

A. Not as of this time. EPE continues to plan for transitioning from its older conventional

[3] Inactive Reserve is defined as the state in which a unit is unavailable for service but can be brought back into service "after some repairs", and the phrase "after some repairs" is defined to mean that some action may be needed to prepare the unit for service because it had been sitting idle for a period of time, and some equipment parts have deteriorated or need replacing before the unit can be operated.
https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/GADS_DRI_2024.pdf

steam generating units retiring to adding new generation in the same manner that it has explained to the Commission in each of its generation certificate of convenience and necessity ("CCN") filings since 2019. For resource planning purposes, EPE has continued to designate Newman Unit 1 and Rio Grande Unit 7 as retired as of the end of 2022. The planned retirement date of Newman Unit 2 remains December 2027. Based on these planned retirement dates, EPE has continued seeking out and investing in new generation resources to add to its portfolio, including Newman Unit 6, and several purchased power agreements ("PPAs") for both solar and energy storage facilities. However, there is always some risk in constructing and adding new generating resources to replace retiring units, and EPE has already experienced delays in project completion for both Newman Unit 6 and multiple PPAs. To mitigate this risk, EPE plans to maintain Rio Grande Units 6 and 7 and Newman Unit 1 on inactive reserve whenever possible, but available for service until planned resource additions required to serve load are constructed, completed, and operating. EPE has continued and will continue to use these units as needed to serve customers, instead of taking them out of service. This plan is reasonable because it allows EPE to use existing resources to help ensure safe and reliable service for customers at minimal cost, as new and more efficient replacement resources are added.

Q16. YOU MENTIONED THAT RIO GRANDE UNIT 6 IS NOT IN BASE RATES BUT HAS BEEN PROVIDING ELECTRIC SERVICE TO EPE CUSTOMERS. IS THE COMPANY SEEKING RECOVERY OF O&M COSTS RELATED TO RIO GRANDE UNIT 6?

A. Yes. As EPE witness George Novela explains in his direct testimony, EPE is seeking to recover the O&M costs related to Rio Grande Unit 6 that the Company incurred during the Test Year through the Retiring Plant Rider. The Company makes this request because although it has been out of EPE's base rates since 2016, Rio Grande Unit 6 was moved from inactive reserve to active service on March 5, 2022, so that it could support peak demand. Since that time, and during the Test Year, the unit has actively served Texas customers. Rio Grande Unit 6 operates primarily as a load-following unit during the summer peak season and to support system needs during planned transmission maintenance or during generation outages.

Q17. WHAT O&M COSTS RELATED TO RIO GRANDE UNIT 6 WERE INCURRED DURING THE TEST YEAR THAT EPE IS REQUESTING TO BE INCLUDED IN THE RETIRING PLANT RIDER?

A. The total costs incurred for O&M of Rio Grande Unit 6 during the Test Year are approximately $1.1 million. These costs covered required maintenance for various components such as the boiler, cooling towers, turbine, generator, condenser, electrical switchgear, lubricating oil systems, and pump and motor repairs, among various other miscellaneous repair and maintenance activities needed to keep the unit reliably operational. These costs also include internal labor, labor overhead, contractor, and material costs. These expenses were reasonably and prudently incurred by EPE so that Rio Grande Unit 6 could safely and reliably provide needed capacity to EPE's Texas load. As has been the case during the last several years, Rio Grande Unit 6 is expected to continue providing service to Texas customers during the summer peak season and to support the completion of planned generation and transmission outages for the foreseeable future.

C. New Power Generation Facilities

Q18. DID EPE ADD ANY NEW GENERATION RESOURCES TO ITS PORTFOLIO FROM JANUARY 1, 2021, THROUGH SEPTEMBER 30, 2024 (THE END OF THE TEST YEAR IN THIS DOCKET)?

A. Yes. EPE added Newman Unit 6, a simple-cycle natural gas-fired combustion turbine unit at its existing Newman Power Station in El Paso, Texas. The nameplate rating of the unit was initially approximately 228 MW based on the elevation at the Newman Power Station location and EPE's summer peak conditions. However, EPE negotiated with Mitsubishi for an additional 3.4 MWs of output from Newman Unit 6, which I discuss in more detail below. While in its normal start-up procedure, Newman Unit 6 can be on-line and achieve full load capability much more quickly than the other units at the Newman Power Station. Newman Unit 6 marks the first addition of a discrete new power generation facility to EPE's local generation fleet since 2016. Newman Unit 6 commenced commercial operations and began serving EPE customers on December 27, 2023.

EPE also added the energy and capacity from a solar generating facility coupled with a battery energy storage system ("BESS") at the Buena Vista Energy Center

("Buena Vista") through a PPA. The solar facility has a nameplate capacity of 120 MW, and the BESS has a 50 MW capacity. EPE witness Martinez discusses the Buena Vista PPA in his direct testimony.

Q19. DO YOU HAVE A PHOTOGRAPH OF NEWMAN UNIT 6?

A. Yes, attached as Exhibit DR-3 are photographs of Newman Unit 6.

Q20. HAS NEWMAN UNIT 6 BEEN INCLUDED IN EPE'S RATE BASE?

A. No, it has not. EPE is requesting that it be included in rate base in this case. I discuss the total invested capital in Newman Unit 6 that EPE seeks to include in rate base later in my testimony.

Q21. DID EPE OBTAIN CCN AUTHORIZATION FOR NEWMAN UNIT 6?

A. Yes. In October 2020, the Commission granted EPE's application to amend its CCN to construct, own and operate Newman Unit 6.[4]

IV. EPE's Local Generation Fleet—Capital Additions

Q22. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section of my testimony is to describe and support cost recovery of the capital additions to EPE's local generation fleet that EPE requests in this application. The scope of this request includes those capital additions placed in service from January 1, 2021, through the Test Year ending September 30, 2024.

A. Methodology and Process

Q23. WHAT IS EPE'S APPROACH FOR CAPITAL ADDITIONS TO ITS LOCAL GENERATING FLEET?

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[4] *Application of El Paso Electric Company to Amend Its Certificate of Convenience and Necessity for an Additional Generating Unit at the Newman Generating Station in El Paso County and the City of El Paso*, Docket No. 50277, Order (Oct. 16, 2020).

A. EPE strives to maintain efficient and reliable power plant operations. This requires capital projects that maintain or improve the performance, availability, and reliability of EPE's local generation fleet. To determine appropriate, reasonable, and timely capital investments for meeting these goals, EPE assesses current and future energy needs, evaluates available technologies, and considers regulatory and environmental requirements.

Q24. FOR CAPITAL ADDITION PROJECTS AT ITS EXISTING LOCAL GENERATION FLEET, DOES EPE USE A COMPETITIVE BIDDING PROCESS?

A. Yes, EPE typically utilizes competitive bidding in its procurement strategy for purchases above $100,000. EPE may utilize Single or Sole Source Policy Waivers approved at the executive level when engaging vendors with specific skills or expertise that are more qualitative in nature, such as engineering and architectural services, for example, or when a product or service is only offered through one vendor. Formal competitive bids are typically coordinated by EPE's Supply Chain Management group.

Q25. WHAT COMPANY PROCEDURES AND PROCESSES ARE IN PLACE TO ENSURE THE REASONABLENESS OF THE COSTS ASSOCIATED WITH POWER GENERATION CAPITAL PROJECTS?

A. Non-stock materials and construction services for power generation projects exceeding $100,000 are typically procured through a formal competitive bidding process.

A purchase requisition with all necessary information and approvals is then submitted to EPE's Supply Chain Management group for processing. All requests for bids, with appropriate EPE bid number and bid due dates, are sent to a minimum of three qualified and approved suppliers, provided that three qualified and approved suppliers exist for that product or service. For certain major projects including Newman Unit 6, EPE typically retains the services of third-party consultants, including independent evaluators, to advise and assist EPE with obtaining and evaluating competitive bid proposals.

Q26. WHAT INFORMATION IS INCLUDED IN THE REQUEST FOR BIDS THAT EPE PROVIDES FOR CONTRACTOR SERVICES?

A. Bid specifications include a statement of work and clearly state the supplier's obligations and responsibilities for all areas of the work or services to be performed, including but not limited to safety, sanitation, and all other aspects of the work to be performed or services to be provided. Bid specifications include a time frame for the completion of work or service. Specifications may also include a detailed performance guarantee clause, if applicable. Additionally, pre-bid meetings and tours of the project site(s) are conducted when appropriate.

Q27. DOES EPE FOLLOW A PROCESS WHEN IT RECEIVES THE BIDS FROM SUPPLIERS?

A. Yes. Upon receipt of all bids, Supply Chain Management evaluates and ranks the bids based on best value and may coordinate with the respective business unit(s) as needed. The Supply Chain Management group will then issue a summary report to the requestor with their recommendation. It includes price quotes by supplier, copies of the bids, the recommended supplier, and the reason(s) for the selection. All information received pertaining to bid packages will remain confidential and supplier pricing and services are not discussed with competing suppliers. Supply Chain Management may notify all bidding participants when the bid has been awarded. Work performed by contractors or consultants will begin after a purchase order ("PO") has been issued. Contractors and consultants must provide proof of insurance before a PO is issued.

The Company reserves the right to reject any or all bids. Additionally, the Company reserves the right to deviate from written policies and procedures when, upon a showing of good cause and with the approval of executive leadership, it is in the best interest of the Company and its customers.

Q28. IS THERE A LIST OF THE MAJOR PRODUCTION PLANT CAPITAL ADDITIONS TO THE LOCAL GENERATION FLEET THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. Yes, EPE witness Cynthia Prieto includes a list of all plant additions that EPE made from January 1, 2021, through September 30, 2024, including for local generation in her Exhibit CSP-2. The local generation capital additions fall under the "Steam Production" and "Other Production" categories in her exhibit. The total Company amount of local generation capital additions, not including Newman Unit 6, is $268,109,617. As previously stated, I sponsor the reasonableness and prudence of the capital expenditures for these projects.

B. Larger Capital Additions

Q29. WHAT ARE SOME OF THE LARGER LOCAL GENERATION CAPITAL ADDITIONS THAT EPE SEEKS TO INCLUDE IN RATE BASE?

A. I use a $5 million threshold to identify large capital additions. Capital additions over $5 million related to EPE's local generation, as identified in EPE witness Prieto's Exhibit CSP-2, that EPE is requesting to be included in rate base are listed below in Table DR-2:

TABLE DR-2

LOCAL GENERATION CAPITAL ADDITIONS (OVER $5M)	AMOUNT
1. NEWMAN CAPITAL BLANKET	$16.4M
2. NEWMAN UNIT 3 MAJOR INSPECTION CAPITAL IMPROVEMENTS	$11.9M
3. RIO GRANDE UNIT 8 MAJOR HP/IP TURBINE IMPROVEMENTS	$11.2M
4. NEWMAN UNIT 4 STEAM TURBINE MAJOR - CAPITAL REPLACEMENT	$11.0M
5. NEWMAN U4 GAS TURBINE 1 SPARE TURBINE COMPONENTS	$11.0M
6. NEWMAN U4 GAS TURBINE 2 SPARE TURBINE COMPONENTS	$11.0M
7. COPPER GAS TURBINE - HOT GAS PRESSURE INSPECTION/COMPRESSOR REPLACEMENT	$11.0M
8. COPPER GAS TURBINE REPLACEMENT PARTS (W501B4)	$7.6M
9. RIO GRANDE CAPITAL IMPROVEMENT BLANKET	$7.4M
10. MONTANA STATION CAPITAL IMPROVEMENTS BLANKET	$7.0M
11. NEWMAN U4 GAS TURBINE 2 - 2ND SPARE ROTOR ACQUIRE	$6.8M
12. NEWMAN UNIT 4 GAS TURBINE 1 -501B SPARE BLADED ROTOR	$6.6M
13. NEWMAN UNIT 2 DIST CONTROL SYS UPGRADE	$6.4M
14. NEWMAN UNIT 4 GAS TURBINE1 MAJOR INSPECTION-IMPROVEMENT CAPITAL IMPROVEMENTS	$6.0M
15. NEWMAN UNIT 3 AIR PREHEATER ROTOR REPL	$5.1M
16. GENERATION OPERATIONS CMMS	$8.3M

Q30. THE FIRST PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE GENERATION – NEWMAN CAPITAL BLANKET. WHAT ARE THE TYPES OF PROJECTS INCLUDED IN THE GENERATION – NEWMAN CAPITAL BLANKET WORK ORDER?

A. The Newman Capital Blanket includes capital improvements at the Newman Power Station, including small projects (those with costs expected to be less than $200,000) that do not receive individual capital project work order numbers and small continual improvement capital expenditures. Examples of the small capital projects included in the blanket are work on boilers, pumps, motors, compressors, valves, heat exchangers, piping systems, reverse osmosis systems, battery back-up systems, electrical systems, seasonal readiness, and other miscellaneous capital improvements.

Q31. CAN YOU PLEASE EXPLAIN HOW MANAGEMENT DETERMINES THE NEED FOR A PROJECT ASSIGNED TO THE BLANKET?

A. Projects are assigned to the blanket when the estimated project costs are expected to be below $200,000. These projects typically arise as a result of discovery work (inspections or outages), equipment failure analyses, and critical equipment assessments, and they include projects that are continuous equipment improvement projects with annual costs below $200,000.

Q32. IS THERE A LISTING OF THE CAPITAL PROJECTS INCLUDED IN THE GENERATION – NEWMAN BLANKET WORK ORDER?

A. Yes. Exhibit DR-4 contains a list of all the projects with costs that were expected to be under $200,000 with brief descriptions of each. Capital blankets may also include capital projects above $200,000 when the project cost was initially estimated to be under $200,000, but the project experienced unforeseen change orders during implementation that increased the project cost above the blanket threshold.

Q33. WERE THE COSTS FOR THE NEWMAN CAPITAL BLANKET REASONABLE AND NECESSARY?

A. Yes, these costs were reasonable and necessary for EPE to continue providing customers with safe, efficient, and reliable service from the generating units at its Newman Power Station. Maintaining, modifying, and improving plant equipment is required to maintain plant reliability, manage costs, and realize the useful life of existing equipment. The costs incurred for these projects were reviewed under strong budgetary controls and approved through reasonable managerial decision-making.

Q34. CAN YOU PLEASE DESCRIBE THE STRONG BUDGETARY CONTROLS MENTIONED IN YOUR PREVIOUS ANSWER?

A. Projects included in capital blankets follow EPE's procurement policies, where projects are formally bid out if costs are expected to be above $100,000. Informal bids (price quotes) are encouraged when project costs are expected to be below $100,000. Additionally, the blanket projects are regularly reviewed and approved by EPE's executive leadership team during the annual Capital Budgeting Process or through the monthly budget reforecasting process.

Q35. THE SECOND PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE NEWMAN UNIT 3 MAJOR INSPECTION AND CAPITAL IMPROVEMENTS. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. Initially, this project was scheduled as a major inspection of the turbine and generator and included funds for replacement of some major components. The original budget was $2.8 million for O&M and $700,000 for capital. Like many turbine or generator major inspections and outages, the actual costs can differ substantially once the unit is disassembled for inspection and the condition of major components has been verified. Common work typically performed during these types of outages includes performing non - destructive testing on critical components; replacing/refurbishing components to restore functionality on main stop valves, control valves, reheat stop valves, intercept valves and blowdown valves; restoring babbit on bearings; and replacing steam seals in the steam path, among various other miscellaneous work. In this case, a series of technical failures pushed the unit into an unplanned shutdown that resulted in equipment damage.

Exhibit DR-5 is an event summary performed by Burns & McDonnell, an EPE engineering consultant, based upon its independent investigation of the unplanned shutdown.

Q36. WHAT EQUIPMENT WAS DAMAGED AND WHAT WAS THE CAUSE?

A. A failure in the unit's Uninterruptible Power Supply ("UPS") caused the control system battery to run low. As a result, the main AC lube oil system experienced a malfunction. Subsequently, the AC and DC back up lube oil systems were unable to energize, which led to the steam turbine coasting to a complete stop in a short period of time. This stoppage resulted in component damage that included the wiping of bearing, seals, and packing due to the loss of oil. The damage to Newman Unit 3 caused subsequent damage to the generator lagging and turbine enclosure. Weld repairs and machining of the rotor journals, refurbishment of all bearings, repair of all steam seals, and replacement of several rows of blades were needed to get the unit back to its normal operating condition.

Q37. DID THIS DAMAGE RESULT FROM EPE'S IMPROPER OPERATION OR MAINTENANCE OF THE EQUIPMENT?

A. No. EPE was not imprudent in how it operated and maintained this unit. The technical analysis performed for the Newman Unit 3 unplanned outage event showed that it was the result of a cascading sequence of multiple equipment failures As noted in Exhibit DR-5, the event summary prepared by Burns & McDonnell, the unplanned outage at Newman Unit 3 resulted from a faulty UPS and associated notification systems that subsequently caused the back-up battery system to lose its charge and prevented the backup pumps from starting as needed when the unit experienced the loss of power condition.

Q38. WAS THERE ALSO A PLANNED OUTAGE SCHEDULED FOR NEWMAN UNIT 3 DURING THE TEST YEAR?

A. Yes. A planned outage at Newman Unit 3 was scheduled to begin on November 12, 2023. The planned outage was scheduled for 174 days, which would have kept Newman Unit 3 out of service until May 4, 2024. During that planned outage, EPE intended to conduct a major inspection of the turbine and generator and to perform the common work typically performed during these types of outages that I described above, and the Company had set aside funds for potential replacement of major components.

Q39. HOW DID THE FORCED OUTAGE AND REPAIRS REQUIRED TO ADDRESS THAT ISSUE COINCIDE WITH THE PLANNED OUTAGE WORK THAT WAS ALREADY SCHEDULED?

A. As noted, the planned outage was set to occur November 12, 2023, but the unplanned event occurred on June 28, 2023. As a result, much of the work needed to place the unit back in service for the unplanned event would have been required to be performed during the planned outage but was instead performed slightly ahead of schedule during the forced outage resulting from the unplanned shutdown. The additional work performed that was above and beyond what would have been needed during the planned outage effectively extended the useful life of the turbine and generator by approximately five years. A letter from one of EPE's turbine and generator contractors (Ethos Energy) is included as Exhibit DR-6 (Confidential) to my testimony; the letter supports EPE's position regarding the five - year service life extension. The benefit of extending the useful life of the 90-MW Newman Unit 3 for an additional five years is approximately $10.6 million in deferred capital costs. The direct testimony of EPE witness Martinez addresses the analysis performed to estimate the value of extending this unit's useful life by five years.

Q40. WAS THIS EVENT COVERED BY EPE'S INSURANCE POLICY?

A. Yes. EPE's insurance carrier reimbursed EPE approximately $1.8 million net of the deductible. EPE's deductible was $5 million.

Q41. THE THIRD PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE RIO GRANDE UNIT 8 MAJOR HIGH PRESSURE / INTERMEDIATE PRESSURE (HP/IP) TURBINE IMPROVEMENTS PROJECT. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The Rio Grande Unit 8 Major HP/IP Turbine Improvement Project was a planned scheduled project undertaken to open and inspect the major turbine components and replace/refurbish as needed. Once the unit had been opened and inspected, the team identified the need for work to refurbish the rotor and inner cylinder shell; to replace blades, diaphragms, blade rings, seals, brackets; and for miscellaneous refurbishment of blade welds and various valve components. Additionally, the generator radial leads required refurbishment, and the full turbine/generator train required realignment. This project re - established efficient and effective operations of the unit in accordance with the original design specifications of the equipment.

Q42. THE FOURTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE NEWMAN 4 STEAM TURBINE MAJOR CAPITAL REPLACEMENT. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The Newman 4 Steam Turbine Major Capital Replacement project was originally planned and scheduled as a valve outage. While performing a borescope inspection, the Company identified damage to turbine blades that required replacement. The outage was reclassified as a major inspection, the damaged turbine components were replaced and extensive maintenance on the generator was performed. This project allowed the unit to continue operating efficiently and effectively in accordance with the design specifications of the equipment.

Q43. THE FIFTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE NEWMAN UNIT 4 GAS TURBINE 1 (GT-1) SPARE TURBINE COMPONENTS. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The Newman U4 GT-1 Spare Turbine Components project involved the purchase and use of a replacement set of rotating, stationary, and combustion components for the gas turbine to replace aging parts that had exceeded their serviceable life. These components are long - lead items and needed to be purchased in advance of the planned outage to execute the work in an efficient and effective manner. This project, along with the subsequent planned outage project, re-established safe and reliable operation of the unit in accordance with the design specifications of the equipment. These components were installed on U4 GT-1 during the major planned outage for this unit during the Test Year.

Q44. THE SIXTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 IS THE NEWMAN UNIT 4 GAS TURBINE 2 (GT-2) SPARE TURBINE COMPONENTS. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. Similar to GT-1, the Newman U4 GT-2 Spare Turbine Components project involved the purchase and use of a replacement set of rotating, stationary, and combustion components for the gas turbine to replace aging parts that had exceeded their serviceable life. These components are long-lead items and needed to be purchased in advance of the planned outage to execute the work in an efficient and effective manner. This project, along with the subsequent planned outage project, re-established safe and reliable operation of the unit in accordance with the design specifications of the equipment. These components were installed on U4 GT-2 during the major planned outage for this unit during the Test Year.

Q45. THE SEVENTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-02 ABOVE IS THE COPPER GAS TURBINE – HOT GAS PATH INSPECTION / COMPRESSOR CAPITAL IMPROVEMENTS. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The Copper Gas Turbine Hot Gas Path Inspection / Compressor Capital Improvements project was originally budgeted to perform a periodic inspection on the turbine and compressor. However, unforeseen and unexpected damage to the turbine was identified during the borescope inspection prior to the planned outage. This discovery created the need to order replacement components in advance of the outage. I discuss these replacement parts in more detail below. The unexpected damage subsequently caused an unplanned outage on the unit due to a rotating turbine blade failing and impacting stationary blades, which created the need to begin major inspection and maintenance work earlier than originally scheduled. This work entailed a comprehensive examination of the turbine and casing to identify and address wear and damage and to restore the safe and reliable operation and performance of the unit. Additionally, the compressor hook-fits were reestablished and the spare rotor with the new turbine rotor were installed as part of this project. Finally, the generator stator was rewound.

Q46. THE EIGHTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE COPPER GAS TURBINE CAPITAL REPLACEMENT PARTS. WHAT WAS THIS PROJECT AND WHY WAS IT UNDERTAKEN?

A. The Copper Gas Turbine Capital Replacement Parts Project was undertaken to procure long-lead gas turbine replacement parts for the major unit outage to support the efficient and effective execution of the project. Parts were purchased in conjunction with the seventh project in Table DR-2 above, which was the Copper Unit's Hot Gas Path Major inspection project that I just described. These parts included, but were not limited to, combustion baskets, transitions, transition seals, diaphragms, fuel nozzles, compressor blades, vanes, and rotor air cooling pipe.

Q47. THE NINTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE GENERATION – RIO GRANDE BLANKET. WHAT ARE THE TYPES OF PROJECTS INCLUDED IN THE GENERATION – RIO GRANDE BLANKET WORK ORDER?

A. The Generation – Rio Grande Blanket includes capital improvements at the Rio Grande Power Station, including small capital projects that do not receive individual capital project work order numbers. Examples of the small capital projects at the Rio Grande Power Station include work on boilers, pumps, motors, compressors, valves, heat exchangers, piping systems, reverse osmosis systems, battery back-up systems, electrical systems, seasonal readiness, and other miscellaneous capital improvements.

Q48. IS THERE A LISTING OF CAPITAL PROJECTS INCLUDED IN THE GENERATION – RIO GRANDE BLANKET WORK ORDER?

A. Yes. Exhibit DR-4 contains a list of all the projects under $200,000 with brief descriptions. Capital blankets may also include capital projects above $200,000 when the project cost was initially estimated to be under $200,000, but the project experienced unforeseen change orders during implementation that increased the project cost above the blanket threshold.

Q49. THE TENTH PROJECT IN YOUR LARGE CAPITAL ADDITIONS TABLE DR-2 ABOVE IS THE MONTANA CAPITAL BLANKET. WHAT ARE THE TYPES OF PROJECTS INCLUDED IN THE MONTANA CAPITAL BLANKET?

A. The Montana Capital Improvement Blanket consists of capital improvements at the Montana Power Station, primarily including capital projects under $200,000 that do not receive individual capital project work order numbers. Examples of the small capital projects at the Montana Power Station include work on pumps, motors, compressors, valves, heat exchangers, piping systems, reverse osmosis systems, battery back-up systems, electrical systems, seasonal readiness, and other miscellaneous capital improvements.

Q50. IS THERE A LISTING OF CAPITAL PROJECTS INCLUDED IN THE MONTANA CAPITAL BLANKET WORK ORDER?

A. Yes. Exhibit DR-4 contains a list of all the projects under $200,000 with brief descriptions. Capital blankets may also include capital projects above $200,000 when the project cost was initially estimated to be under $200,000, but the project experienced unforeseen change orders during implementation that increased the project cost above the blanket threshold.

Q51. CAN YOU PLEASE EXPLAIN HOW MANAGEMENT DETERMINED THE NEED FOR A PROJECT ASSIGNED TO THE MONTANA AND RIO GRANDE BLANKETS?

A. As previously noted in my testimony regarding the Newman Capital Blanket project, projects are assigned to blankets when the total estimated project costs are expected to be below $200,000 and often arise as a result of inspections, scheduled or unscheduled outages, equipment failure analyses, and critical equipment assessments.

Q52. WERE THE COSTS FOR THE RIO GRANDE AND MONTANA CAPITAL BLANKETS REASONABLE AND NECESSARY?

A. Yes, these costs were reasonable and necessary for EPE to continue providing customers with safe, efficient, and reliable service from the generating units at its Rio Grande and Montana Power Stations. Maintaining, modifying, and improving plant equipment is