BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

APPLICATION FOR APPROVAL OF EL PASO ELECTRIC COMPANY'S 2018 RENEWABLE ENERGY PLAN PURSUANT TO THE RENEWABLE ENERGY ACT AND 17.9.572 NMAC, AND REVISED RATE NO. 38 – RPS COST RIDER	)	CASE NO. 18-00109-UT
EL PASO ELECTRIC COMPANY, Applicant.	)	

DIRECT TESTIMONY

OF

JAMES SCHICHTL

MAY 1, 2018

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EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JAMES SCHICHTL

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James Schichtl, and my business address is 100 North Stanton Street, El Paso, Texas, 79901.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE") as Vice President of Regulatory Affairs.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I have been employed by EPE since February 2012. In June 2016, I was promoted from Director of Regulatory Affairs to Vice President. Prior to becoming Director, I was manager of EPE's Economic & Rate Research group, responsible for EPE's jurisdictional cost of service, rate design analysis, and developing EPE's retail rate schedules and charges. Prior to that, I was a Senior Regulatory Case Manager, responsible for the production, filing, and execution of regulatory applications before both the Public Utility Commission of Texas ("PUCT") and the New Mexico Public Regulation Commission ("NMPRC" or "Commission").

Prior to joining EPE in February 2012, I spent 18 years in various regulatory functions at Southern California Edison Company ("SCE"), 12 of those in a managerial capacity. As Manager of Pricing Design and Research, I was responsible for SCE's rates and tariffs during deregulation and changes required in following the California power crisis in 2001. I was subsequently promoted to Manager of Tariffs and Advice Letters, with broad responsibility within regulatory for evaluating California statute, rules, and regulations and managing regulatory efforts at the California Public Utilities Commission ("CPUC"). Those efforts included significant involvement in the transition back to a deregulated generation market as well as significant expansion of distributed generation in California.

I graduated with a Bachelor of Science in Mechanical Engineering in 1987 from the University of Texas at El Paso, where I also studied economics and econometrics. Throughout my career at EPE, I have attended and presented material for numerous seminars and workshops related to cost of service, rate and program design, and regulation.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As Vice President of Regulatory Affairs, I am responsible for the oversight and direction of EPE's Economic Research, Rate Research, and Regulatory

Accounting groups, as well as EPE's Regulatory Case Management group. Economic Research performs load research and analysis, and forecasting functions. Rate Research encompasses EPE's rate research function, jurisdictional and class cost of service studies, rate design analysis, and the development of retail rate schedules and charges. The Regulatory Accounting group is responsible for the scheduling, preparation and review of jurisdictional regulatory accounting and reporting. The Regulatory Case Management group coordinates and oversees regulatory filings made by EPE with the PUCT, NMPRC, the Federal Energy Regulatory Commission ("FERC"), and local municipal regulators.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS FILING?

A. Yes, I am sponsoring Exhibit JS-1, Historical Compliance and Procurement Cost, and Exhibit JS-2, which provides EPE's Rate Schedule No. 38 - Renewable Portfolio Standard ("RPS") Cost Rider ("RPS Rider") revised to reflect RPS procurement costs for the 2019 Plan Year.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with and testified before the NMPRC, PUCT, FERC and the CPUC.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I introduce EPE's other witnesses in this case, and discuss RPS issues from a regulatory policy perspective. I briefly describe issues addressed in the Final Order in Case No. 17-00090-UT, EPE's 2017 Plan proceeding, which impact EPE's current plan filing, and I provide an overview of EPE's existing waivers and variances from its 2018 and 2019 Plan Year RPS and diversity requirements. I discuss the history of EPE's procurements with respect to the Reasonable Cost Threshold ("RCT"), and describe a proposed revision to the calculation EPE is presenting in this plan filing. I also describe and discuss EPE's approved RPS Rider for recovery of EPE's Commission-approved RPS procurement costs. Finally, I provide an overview of EPE's existing Renewable Energy Credit ("REC") purchase program, which was closed to new customers by Commission final order in Case No. 17-00090-UT.

Q. WHO ARE THE OTHER WITNESSES TESTIFYING FOR EPE IN THIS CASE?

A. EPE employees Omar Gallegos and Manuel Carrasco provide testimony in support of EPE's application. EPE witness Gallegos presents the requirements of the Renewable Energy Act ("REA") and Rule 17.9.572 NMAC ("RPS Rule" or "Rule 572"), and EPE's 2018 RPS Plan ("2018 Plan") for plan year and next plan year approval. EPE witness Gallegos additionally addresses extension of the Camino Real Landfill to Energy Facility REC procurement, and EPE's request for a partial waiver from the 2020 total RPS requirement as well as a required variance to the 2020 Wind and Biomass/Other diversity requirements. EPE witness Carrasco describes and supports EPE's application of the RCT calculation relative to the RPS portfolio cost, including calculation of the impact of the proposed change to the RCT analysis that I discuss later in my testimony. He also presents the determination of the large customer adjustment to EPE's annual RPS requirement for the 2019 and 2020 plan years. Finally, EPE witness Carrasco calculates EPE's proposed RPS Rider rate for 2019 for recovery of RPS procurement costs for 2019, and for informational purposes for 2020.

III. RENEWABLE PORTFOLIO STANDARD ISSUES

Q. IN ITS FINAL ORDER APPROVING EPE'S 2017 PLAN, DID THE COMMISSION IDENTIFY ANY ISSUE RELEVANT TO EPE'S 2018 APPLICATION?

A. Yes. In the Final Order in Case No. 17-00090-UT, the Commission approved EPE's proposed RPS Rider for recovery of certain, specified RPS expenses, and ordered that EPE work with the Commission's Utility Division ("Staff") regarding the presentation of the rate rider on customer bills and the proposed computations prior to the first billed rate rider.

Q. HOW DID EPE COMPLY WITH THE COMMISSION'S DIRECTIVE TO WORK WITH STAFF REGARDING THE NEW RPS RIDER?

A. EPE provided information to Staff on the calculation of the RPS Rider and its presentation in customer bills prior to implementing the new billing mechanism. The Commission-approved RPS Rider was filed as EPE's compliance Advice Notice No. 253 as Original Rate No. 38 - Renewable Portfolio Standard (RPS) Cost Rider and implemented by EPE effective January 1, 2018, as a single line item bill charge.

IV. OVERVIEW OF EPE'S TOTAL RPS AND DIVERSITY REQUIREMENTS

Q. BASED ON EPE'S COMMISSION APPROVED RPS PLANS, PLEASE PROVIDE AN OVERVIEW OF HOW EPE HAS MET ITS TOTAL RPS AND DIVERSITY REQUIREMENTS?

A. EPE met 100 percent of its total RPS requirements through 2015 as demonstrated through EPE's annual RPS reports on file with the Commission. EPE's 2017 Report, filed concurrently with this 2018 Plan Year application, shows that EPE was required to use a Commission-approved partial waiver from total RPS for the 2017 Plan Year. The 2017 Report shows that EPE retired RECs representing 11.2% of its New Mexico adjusted energy requirements in 2017, or 77.1% of required RECs. EPE was also required to use approved variances from 2017 Wind and Biomass/other diversity targets in the 2017 Plan Year. The Commission approved the partial waiver and variances for 2017 in EPE's 2015 Plan proceeding, Case No. 15-00117-UT.

Q. IN EPE'S 2016 AND 2017 PLAN PROCEEDINGS, CASE NOS. 16-00109-UT AND 17-00090-UT, THE COMMISSION GRANTED EPE WAIVERS FROM THE 2018 AND 2019 TOTAL RPS REQUIREMENTS AND VARIANCES FROM THE 2018 AND 2019 WIND AND BIOMASS/OTHER DIVERSITY REQUIREMENTS. DOES EPE ANTICIPATE THAT IT WILL BE REQUIRED TO USE THOSE APPROVALS FOR 2018 AND 2019?

A. Yes, EPE anticipates that it will need to use its waivers from 2018 and 2019 Total RPS and variances from 2018 and 2019 Wind and Biomass/Other targets for 2018

Plan Year compliance. As discussed by EPE witness Gallegos, EPE is requesting a similar waiver and similar variances for 2020.

Q. PLEASE EXPLAIN WHY EPE HAS HAD TO SEEK WAIVERS FROM TOTAL RPS REQUIREMENTS AND VARIANCES FROM DIVERSITY TARGETS FOR PAST AND CURRENT PLAN YEAR APPLICATION PROCEEDINGS.

A. Under the Commission's current RPS Rule's RCT calculation, EPE's previously approved procurement costs included in EPE's recent REA plan applications were in excess of the RCT. Specifically, and as an example, in the 2017 Plan Final Order in Case No. 17-00090-UT the Commission found that "EPE will exceed the 3% RCT for 2018 Plan Year by $6,600,890 and by $6,721,228 in 2019." As calculated in the direct testimony of EPE witness Carrasco, the ratio of EPE's compliance cost, or revenue requirements to plan year total revenues, was projected in that case at 6.54% in 2018 and 6.59 % in 2019, far exceeding the RCT of 3%.

Q. PLEASE EXPLAIN WHY EPE'S PREVIOUSLY APPROVED PROCUREMENT COSTS NOW EXCEED THE RCT UNDER THE COMMISSION'S CURRENT RPS RULE.

A. In 2013 and 2014, the Commission amended Rule 572 to modify the methodology by which the RCT is evaluated so that plan year costs are calculated as revenue requirements that reflect how a procurement plan will impact customer bills in the plan year. Because the point of the statutory RCT is to limit rate impact resulting from the RPS requirement to a certain percentage over current base rates, the Commission amended its RCT methodology to require utilities to calculate the actual annual revenue requirement of the procurement plan, net of actual avoided costs, to determine compliance costs under the RCT. The result was that EPE's compliance cost as a percentage of plan year revenues (the RCT metric) increased in one year; even though EPE's total procurement cost decreased in the same period. In short, the apparent RCT increase is caused more by changes to the calculation method than to actual procurement cost increases.

Exhibit JS-1 summarizes the procurement and compliance costs for RCT purposes for the 2010 Plan Year filing through EPE's most recent filing in 2017. It demonstrates that although EPE's total procurement plan costs actually decreased from the 2013 to 2014 Plan Years, RPS compliance cost (as defined by the Rule) increased significantly as a percentage of annual revenues. The significant increase in the compliance costs in 2014 result almost entirely from the removal of over $20 million in avoided capacity costs from the RCT analysis, which was necessitated by the change in the RPS rule.

Q. IS EPE PROPOSING AN ALTERNATIVE RCT ANALYSIS FOR COMMISSION CONSIDERATION IN THIS PLAN APPLICATION?

A. Yes. As calculated by EPE witness Carrasco, EPE is proposing a change to its RCT analysis to reflect base revenue reductions as cost savings realized, in theory, by customers in the plan year and next plan year. These projected savings are reflected in current rates and result from the treatment of RPS energy in EPE's 2015 rate case and the impact of that treatment on the allocation of base revenue requirements to New Mexico customers.

Q. HOW DOES EPE TREAT THE ENERGY PROVIDED BY ITS NEW MEXICO RPS PORTFOLIO IN GENERAL RATE CASES?

A. The energy procured by EPE through the RPS portfolio is directly assigned to EPE's New Mexico jurisdiction to determine jurisdictional cost of service ("JCOS") allocation factors.

Q. WAS THIS DIRECT ASSIGNMENT OF RPS ENERGY AND THE ALLOCATION PROPOSED BY EPE IN ITS MOST RECENT RATE CASE?

A. Yes. EPE's proposed revenue requirement for New Mexico filed in Case No. 15-00127-UT reflected direct assignment of RPS energy and the resulting allocators.

Q. **PLEASE IDENTIFY AND EXPLAIN THE RATE IMPACT OF THIS DIRECT ASSIGNMENT OF RPS ENERGY.**

A. This direct assignment of RPS energy to New Mexico reduces the allocation to New Mexico of costs (rate base and expenses) associated with system resources. Basically, because renewable generation is procured for New Mexico customers through the RPS, fewer system resources are required to serve New Mexico load. All other things being equal, this reduces the total revenue requirement and base rates requested for New Mexico.

Q. **HAS EPE ESTIMATED THE ABOVE-DESCRIBED IMPACT OF THE RPS PORTFOLIO ON THE BASE RATES APPROVED IN EPE'S 2015 RATE CASE NO. 15-00127-UT?**

A. Yes. EPE compared the JCOS approved by the Commission for New Mexico in its 2015 rate case (which incorporated the RPS portfolio energy in allocation factors described above), with a revised JCOS using unadjusted allocation factors. The difference in jurisdictional revenue requirement between the two scenarios is approximately $6,035,492. This indicates that, all other things being equal, EPE's requested revenue requirement for New Mexico would have been higher but for the energy supplied by the RPS portfolio and reflected in jurisdictional allocation factors.

Q. WHAT IS MEANT BY THE QUALIFIER "ALL OTHER THINGS BEING EQUAL"?

A. The comparison requires a revenue requirement analysis in which system resources are assumed to be unchanged and not to be impacted by the absence of an RPS portfolio. This analysis and assumptions used are consistent with those underlying the PROMOD analysis used for the Direct Methodology analysis for the RCT. Also, the analysis assumes that any difference in requested revenue requirement resulting from the treatment of RPS energy actually translates, through a final Commission order, into the equivalent magnitude reduction in base rates.

Q. DOES THIS MEAN THAT NEW MEXICO CUSTOMERS RECEIVE A NET SAVINGS IN THEIR BILLS AS A RESULT OF THE RPS PORTFOLIO?

A. No. Although the impact of RPS energy alone on allocation factors and revenue allocation would suggest lower base rates, overall costs for customers—which include fuel and purchased power costs, and RPS Rider costs—are higher because the system resource costs avoided through RPS energy are lower cost than the RPS portfolio resources. This explains the fact that EPE's RCT analysis produces a positive value, because the overall costs are higher even assuming the reduced revenue requirements described here

Q. SHOULD THE REVENUE REQUIREMENT IMPACT OF THE RPS PORTFOLIO BE REFLECTED IN THE RCT ANALYSIS OF THE PORTFOLIO COST?

A. Yes. It is reasonable to reflect these projected base revenue reductions in the RCT analysis because they are theoretically realized in the plan year revenue requirements, consistent with the requirements for the RCT calculation in Section 14(C) of the RPS Rule. Netting these base revenue requirement savings from plan year procurement costs in the RCT analysis reduces EPE's compliance costs to 4.31% of plan year total revenues in 2019 and 3.89% of plan year total revenues in 2020. EPE witness Carrasco presents this alternative RCT analysis in his Exhibit MC-4.

V. EPE'S RPS COST RIDER

Q. DOES EPE CURRENTLY HAVE A RATE RIDER FOR PURPOSES OF RECOVERING COSTS ASSOCIATED WITH THE RPS?

A. Yes, Rate No. 38 - Renewable Portfolio Standard (RPS) Cost Rider was approved by Commission's Final Order in Case No. 17-00090-UT and implemented effective January 1, 2018.

Q. HOW WERE COSTS ASSOCIATED WITH APPROVED RENEWABLE ENERGY ACT PLANS RECOVERED BY EPE PRIOR TO APPROVAL OF THE RPS RIDER?

A. Prior to January 1, 2018, Final Procurement Plan Orders authorized EPE to recover approved plan year RPS costs either through the Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") mechanism or to defer them for recovery through base rates. In those cases, deferred costs were limited to the cost of stand-alone REC purchases (without associated energy) and costs associated with registering RECs with Western Renewable Energy Generation Information System ("WREGIS") for recovery base rates. RPS costs recovered through the FPPCAC included the cost of energy and associated RECs.

Q. WHAT COSTS DOES EPE CURRENTLY RECOVER THROUGH THE RPS RIDER?

A. Since January 1, 2018, EPE has been recovering energy and associated REC costs through the RPS Rider, based on the rate approved by Commission Final Order in

Case No. 17-00090-UT. These costs had previously been recovered through the monthly FPPCAC.

Q. HOW DID EPE REMOVE THOSE COSTS FROM THE FPPCAC FOR INCLUSION IN THE RPS RIDER?

A. Prior to the approval of EPE's RPS Rider, monthly RPS costs were estimated for FPPCAC purposes based on actual RPS costs for the period two-months prior. For example, RPS portfolio costs for recovery through the FPPCAC in December 2017 billings were estimated based on actual RPS costs in October 2017. In addition, the FPPCAC included a true-up amount to reflect the difference between the estimated and actual costs for the period two-months prior. Beginning with the January 2018 FPPCAC calculation, no current RPS-related costs are included in the FPPCAC calculation, but are instead recovered through the RPS Rider.[1]

Q. DID THE COMMISSION AUTHORIZE EPE TO RECOVER ANY OTHER RPS COSTS THROUGH THE RPS RIDER?

A. Yes. The Final Order in EPE's 2017 RPS case authorizing the RPS Rider also approved recovery of WREGIS-related costs through the rider. Estimated

[1] True-up amounts for November and December 2017 as determined in January and February 2018 based on the RPS cost recovery mechanism reflected in monthly FPPCAC calculations in 2017 remain with the FPPCAC calculation for January and February 2018.

WREGIS costs for 2018 were included in the rate approved by Commission Final Order in Case No. 17-00090-UT.

Q. ARE ANY OF EPE'S RPS COSTS CURRENTLY RECOVERED THROUGH ITS BASE RATES?

A. Yes, stand-alone REC costs (without associated energy) and WREGIS costs previously deferred pursuant to Final Orders through the end of the 2014 test year in EPE's most recent rate case are currently recovered through base rates. In the Final Order in EPE's 2015 rate case (Case No. 15-00127-UT), the Commission authorized recovery of $1.115 million of deferred REC costs through base rates annually for 5 years.

Q. DOES EPE CONTINUE TO DEFER ANY APPROVED RPS COSTS FOR RECOVERY IN BASE RATES?

A. Yes. As of March 31, 2018, RPS costs of $805,679 for stand-alone REC purchases (without associated energy), which have been deferred since the 2014 test year in EPE's 2015 rate case, are deferred and not included in the rider. Recovery of these costs will continue to be deferred, with carrying charges, until approved in EPE's next rate case, planned for mid-2019.

Q. IS EPE PROPOSING TO IMPOSE RATE CAPS ON ITS LARGE CUSTOMERS THROUGH ITS PROPOSED RPS COST?

A. Yes. As shown in the direct testimony and exhibits of EPE witness Carrasco, EPE expects that four of its largest New Mexico customers would qualify under the large customer adjustment criteria in the Rule, based on their historical usage for 2017. EPE's RPS procurement for those large customers is limited to two percent of their annual bills. EPE bills these customers on a monthly basis under the RPS Rider by multiplying the applicable portions of their bill by two percent. This approach ensures that these large customers pay no more than the limit provided for under the Rule.

Q. IS EPE INCLUDING A PROPOSED RATE RIDER TARIFF IN THIS APPLICATION FOR THE 2019 PLAN YEAR?

A. Yes, Rate No. 38 - Renewable Portfolio Standard (RPS) Cost Rider is included with my testimony as Exhibit JS-2. EPE is filing an advice notice concurrent with this application containing the proposed rider for billing in 2019.

VI. <u>DISTRIBUTED GENERATION ("DG") REC PURCHASE PROGRAMS</u>

Q. PLEASE DESCRIBE EPE'S EXISTING SYSTEM REC PURCHASE PROGRAMS.

A. Pursuant to previous Commission approvals, EPE established a Small System REC Program (Rate No. 33 - Small System Renewable Energy Certificate Purchase) to purchase RECs from customers' solar and wind DG facilities with maximum rated capacity of 10 kilowatts ("kW") or less, and a Medium System REC Program (Rate No. 34 - Medium System Renewable Energy Certificate Purchase) to purchase RECs from customers' solar and wind DG facilities with maximum rated capacity greater than 10 kW and up to 100 kW. In NMPRC Case No. 11-00263-UT, the Commission adopted the tiered pricing system for REC purchases through calendar year 2020 shown in the table below. The Tier 5 price established in that case, effective January 1, 2014, was to continue thereafter, and the Commission established a common termination date of December 31, 2020 for all new Small and Medium REC Program contracts ("REC Agreements") beginning January 21, 2012.

		Small System		Medium System	
Tier	Period	Solar	Wind	Solar	Wind
Tier 1	1/12/2012 – 6/30/2012	$0.10	$0.06	$0.12	$0.024
Tier 2	7/1/2012 – 12/31/2012	$0.08	$0.05	$0.09	$0.022
Tier 3	1/1/2013 – 6/30/2013	$0.06	$0.04	$0.06	$0.02
Tier 4	7/1/2013 – 12/31/2013	$0.04	$0.03	$0.04	$0.02
Tier 5	1/12/2014 –	$0.02	$0.02	$0.02	$0.02

EPE offered these programs through the Commission-approved Small and Medium System Renewable Energy Certificate Purchase rates for REC purchase program applications submitted prior to January 1, 2017. Customers were also required to interconnect their facilities in accordance with the DG interconnection rules and agreements established by the Commission.

EPE also currently has an authorized Large System REC Program (Rate No. 35 - Large System Renewable Energy Certificate Purchase) for systems with capacity greater than 100 kW and less than 1 megawatt ("MW"). The REC prices paid under the Large System REC Program are established under individual contracts and are limited by a cap tied to the Medium System REC Program prices. This program was initiated in 2011 pursuant to the Commission's Final Order in Case No. 11-00263-UT.

Q. ARE THE REC PURCHASE PROGRAMS CURRENTLY OPEN TO NEW CUSTOMERS WITH RENEWABLE GENERATION?

A. No. In its final order in Case No. 16-00109-UT adopting EPE's 2016 RPS Plan, the Commission approved EPE's proposal to close the REC purchase programs to new customers effective January 1, 2017. Customers who submitted to EPE an application to participate in a REC purchase program as set forth in EPE's tariffs prior to January 1, 2017, remain eligible to participate in the REC purchase programs and receive the applicable REC credit once their system becomes operational until, with some exceptions, the common termination date of 2020.[2] Customers with interconnection agreements for renewable generation installations submitted after that date are not eligible for the REC purchase programs.

Q. HOW DID THE PROGRAM CLOSURE IMPACT EXISTING PROGRAM PARTICIPANTS?

A. There is no impact of the Commission-approved closure on existing customers. Participating customers with DG systems interconnected and operating prior to January 1, 2017, will continue to participate under the tariffs and continue to receive their designated REC credit, based on the date they originated service under the applicable schedule, at the Commission-approved REC price.

Q. WHEN DO EPE'S REC PURCHASE PROGRAMS TERMINATE?

A. As noted above, the Commission established a common termination date of December 31, 2020, for all REC contracts initiated January 1, 2012 or later under the REC purchase programs. Purchase contracts that were entered into prior to January 1, 2012, had their own identified termination dates, some of which extend into 2013. The table below provides a calendar of planned termination dates and

[2] The 2020 common termination date does not apply to REC purchase agreements entered into prior to the January 1, 2012 implementation of the tiered pricing system for REC purchases described above in my testimony.

the number of customers impacted for DG systems currently participating in the REC purchase programs.

Termination Year of REC Purchases	Number of Customers
2020	1,925
2021	112
2022	182
2023	341

Of all customers currently participating in EPE's REC purchase programs, the contracts of 75% of those customers will terminate on December 31, 2020, and all contracts in the REC purchase programs will terminate by the end of 2023.

Q. DOES CLOSURE OF THE REC PURCHASE SCHEDULES IMPACT THE ABILITY OF NEW DG CUSTOMERS TO INTERCONNECT WITH EPE OR PARTICIPATE IN NET ENERGY METERING?

A. No. New customers continue to be allowed to interconnect their generating facilities and participate under the existing tariff provisions for metering options and sell exported energy to EPE.

Q. HOW MANY SMALL RENEWABLE DG FACILITIES ARE ELIGIBLE TO PARTICIPATE IN EPE'S CURRENT SMALL SYSTEM REC PROGRAM?

A. As of December 31, 2016, 2,656 customer-owned small renewable DG facilities were connected to or had submitted applications to connect to EPE's system in New Mexico, making them eligible to participate in the Small System REC Program. As of March 30, 2018, 2,554 solar DG facilities and 6 wind DG facilities are participating and receiving REC payments under the program. The total capacity for all the REC program eligible small DG systems (the sum of nameplate rated capacity) is 11.6 MW.

Q. WHAT IS EPE'S CURRENT PARTICIPATION IN THE MEDIUM SYSTEM REC PROGRAM?

A. As of December 31, 2017, 135 customer-owned medium renewable DG facilities were connected to or had submitted applications to connect to EPE's system in New Mexico. All of these facilities are solar PV. The total capacity for all the REC program eligible medium DG systems (the sum of nameplate rated capacity) is 3.08 MW.

Q. DOES EPE HAVE CUSTOMERS PARTICIPATING OR ELIGIBLE TO PARTICIPATE IN THE LARGE SYSTEM REC PROGRAM?

A. Yes, EPE currently has 6 systems participating in the large REC purchase program. These systems receive payments based on contractual arrangements with EPE pursuant to the large system REC purchase tariff. The total capacity of these 6 solar systems is 1.5 MW.

Q. WHAT ARE THE EXPECTED ANNUAL COSTS OF THE SMALL, MEDIUM, AND LARGE SYSTEM REC PURCHASE PROGRAMS IN THE 2019 AND 2020 PLAN YEARS?

A. Exhibit OG-3 lists the total cost for the REC Purchase Programs to be approximately $1,799,777 million in 2019 and 2020. Prices paid for RECs by EPE have varied over time and are a function of when a DG system began operation. The annual costs reflect rates ranging from $0.155 to $0.02 per kWh. With REC program tariffs closed to new customers the cost of the combined programs is projected to remain fairly level for 2019 and 2020, although normal variations in DG system energy output would likely result in some differences as would any approved expansions. The bulk of the program costs will drop off after the common termination date of the program in 2020, for customers who applied for interconnection after January 1, 2012.

Q. WITH THE DG REC PROGRAMS CLOSED, DID THE NUMBER OF DG RECS ACQUIRED BY EPE FROM DG CUSTOMERS STABILIZE AROUND 2016 LEVELS AS WELL?

A. No. Because the number of DG systems interconnecting to EPE's system in New Mexico continues to grow, at an average of 335 per year (from the period of 2010 through 2017), the number of RECs produced by these customers and acquired by EPE continues to increase. The REC purchase programs represented payments to DG system owners for the RECs generated by their systems, but EPE remains the owner of DG RECs from all interconnected systems, because EPE purchases the energy produced by these qualifying facility systems. The total quantity of DG RECs produced and registered for RPS compliance in New Mexico, to the benefit of all customers, will continue to increase as new systems interconnect and commence operation.

Q. HOW MANY DG RECS DOES EPE FORECAST WILL BE GENERATED AND ACQUIRED BY EPE IN THE 2019 AND 2020 PLAN YEARS?

A. As of the end of March 2018, EPE had 3,783 customer-owned renewable DG facilities connected to EPE's system, comprised of 3,777 solar DG facilities and 6 wind DG facilities. In addition, applications for 165 DG facilities have been submitted for interconnection or are under construction.

The total capacity for all the DG systems currently operating or under construction (the sum of nameplate rated capacity) is 18.8 MW. As shown in Exhibit OG-3, EPE forecasts generation of 37,086 DG RECs in 2019 and

40,618 DG RECs in 2020. These RECs will be registered in the WREGIS and will be eligible for retirement to satisfy the DG diversity requirement and contribute toward satisfaction of the total RPS requirements in those plan years.

VII. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY AND EPE'S PROPOSALS IN ITS 2018 RPS PLAN FILING?

A. As EPE witness Gallegos describes in his testimony, EPE's 2018 RPS Plan filing is in full compliance with the Rule and should be approved with the necessary waiver and variances. EPE is requesting waiver and variances from total RPS and diversity requirements for 2020, because EPE's total RPS compliance costs as a percentage of New Mexico revenues exceed the RCT. Waiver and variances for 2019 were approved by the Commission in EPE's previous RPS Plan proceeding.

EPE implemented its RPS Rider (Rate No. 38 – Renewable Portfolio Standard Cost Rider) effective January 1, 2017, pursuant to the Commission's Final Order in Case No. 17-00090. EPE proposes to modify tariff language and revise the existing rates in the RPS Rider for billing in 2019 in order to recover its 2019 Plan Year procurement costs through the RPS Rider. The revised tariff is included with an advice notice filed concurrent with this application and shown in Exhibit JS-2.

EPE also requests that the Commission approve modification of the RCT analysis to reflect base rate savings that can be attributed to the treatment of RPS energy in EPE's most recent rate case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EPE Historical Compliance and Procurement Costs

Case No. for Plan Year	10-00200-UT 2011 [1]	11-00263-UT 2012 [2]	12-00217-UT 2013 [3]	13-00223-UT 2014 [4]	14-00121-UT 2015 [5]	15-00117-UT 2016 [6]	16-00109-UT 2017 [7]	17-00090-UT 2018 [8]
Proposed RPS Portfolio Cost	$ 3,475,586	$ 14,222,679	$ 20,230,170	$ 16,193,126	$ 16,421,659	$ 15,238,697	$ 14,793,319	$ 14,207,571
Compliance Cost	$ 1,320,885	$ (4,242,974)	$ (1,904,997)	$ 13,466,047	$ 13,141,484	$ 10,212,666	$ 11,928,966	$ 12,189,304
Plan Year Revenue Requirement	$ 193,639,820	$ 199,147,476	$ 204,289,639	$ 199,026,438	$ 201,966,796	$ 191,221,136	$ 190,973,497	$ 186,280,474
RPS Cost Percentage	0.68%	-2.13%	-0.93%	6.77%	6.51%	5.34%	6.25%	6.54%

Analysis:
RPS portfolio costs increased from 2011 through 2013 as EPE added several large PPA's for solar resources. Until the 2013 Plan Year, the capacity added by these resources and others in the portfolio were credited for avoided costs based on the cost of a combined cycle combustion turbine, which actually resulted in a net credit complaince cost in 2013. Avoided capacity cost of $20.1 million was credited against RPS Portfolio costs in the 2013 Plan Year. Following the change in the RPS Rule, this avoided cost credit was not longer included in the RCT analysis, resulting in a substantial increase in complaince cost expressed as a percenatge of Plan Year revenue requirement even though the total RPS Portfolio cost decreased for the 2014 Plan Year. EPE's RPS Portfolio costs for 2018 are roughly equal to costs for 2012.

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[1] See 2011 Plan Year data provided in Exhibit RA-3, Exhibit EDE-1, and Exhibit EDE-2.
[2] See 2012 Plan Year data provided in Exhibit RA-4, Exhibit EDE-1, and Exhibit EDE-2.
[3] See 2013 Plan Year data provided in Exhibit RA-5, Exhibit CH-1, and Exhibit CH-4.
[4] See 2014 Plan Year data provided in Exhibit JS-1.
[5] See 2015 Plan Year data provided in Exhibit JS-1.
[6] See 2016 Plan Year data provided in Exhibit RA-1 and Exhibit JS-1.
[7] See 2017 Plan Year data provided in Exhibit OG-2 and Exhibit MC-1.
[8] See 2018 Plan Year data provided in Exhibit MC-1.

Exhibit JS-1
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EL PASO ELECTRIC COMPANY

1st REVISED RATE NO. 38 X

RENEWABLE PORTFOLIO STANDARD (RPS) COST RIDER

APPLICABILITY:

This Rider is applicable to bills for electric service provided under all of EPE's retail rate schedules. This Rider is established to recover Renewable Portfolio Standard ("RPS") costs. This Rider is applicable to all customer classes consistent with the New Mexico Public X
Regulation Commission (NMPRC) Rule 17.9.572.7(M) NMAC, and the limitations of NMSA X
1978, Section 62-16-4(A)(2) applicable to certain nongovernmental customers. This Rider is not applicable to customers exempt from charges for renewable energy procurements pursuant to NMSA 1978, Section 62-16-4(A)(3).

TERRITORY:

Areas served by the Company in Dona Ana, Sierra, Otero and Luna Counties.

MONTHLY RATES:

	Rate	
All Retail Rate Schedules, per kWh, except for customers subject to Large Customer Cap	$0.010154	X
Customers Subject to Large Customer Cap	2% of Pre-Tax Charges	X

STATUTORY CAP ON BILLING FOR CERTAIN LARGE CUSTOMERS:

NMPRC Rule 17.9.572.7(M) NMAC limits billed amounts for additional costs associated with RPS procurement for non-governmental customers with consumption exceeding 10 million kWh per year at a single location of facility.

RECONCILIATION FILING: X

This Rider shall be adjusted to reconcile a prior plan year's RPS Cost Rider collections with X
actual RPS costs. Any over-recovery of the previously approved RPS costs will represent a X
credit to and reduction of the approved Rider in a subsequent plan year and any under-recovery X
of the previously approved renewable energy costs will represent a charge in addition to the
approved Rider in a subsequent plan year. The annual reconciliation will also evaluate cost X
recovery from qualifying large customers pursuant to NMPRC Rule 17.9.572.7(M) NMAC. X

Advice Notice No. 257

Signature/Title ____________________
James Schichtl
Vice President – Regulatory Affairs

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

APPLICATION FOR APPROVAL OF EL PASO ELECTRIC COMPANY'S 2018 RENEWABLE ENERGY PLAN PURSUANT TO THE RENEWABLE ENERGY ACT AND 17.9.572 NMAC, AND REVISED RATE NO. 38 – RPS COST RIDER EL PASO ELECTRIC COMPANY, Applicant.	CASE NO. 18-00109-UT

AFFIDAVIT

STATE OF TEXAS)
)
COUNTY OF EL PASO)

James Schichtl hereby deposes and states under oath that the information contained in the foregoing Direct Testimony of James Schichtl, together with all schedules sponsored therein and exhibits attached thereto, is true and accurate based on my personal knowledge and belief.

SIGNED this 30th day of April, 2018.

JAMES SCHICHTL

Subscribed and sworn to before me this 30th day of April, 2018.

Julieta E. Cordero

My Commission expires:

October 2, 2018

JULIETA E. CORDERO
Notary Public, State of Texas
My Commission Expires
October 02, 2018