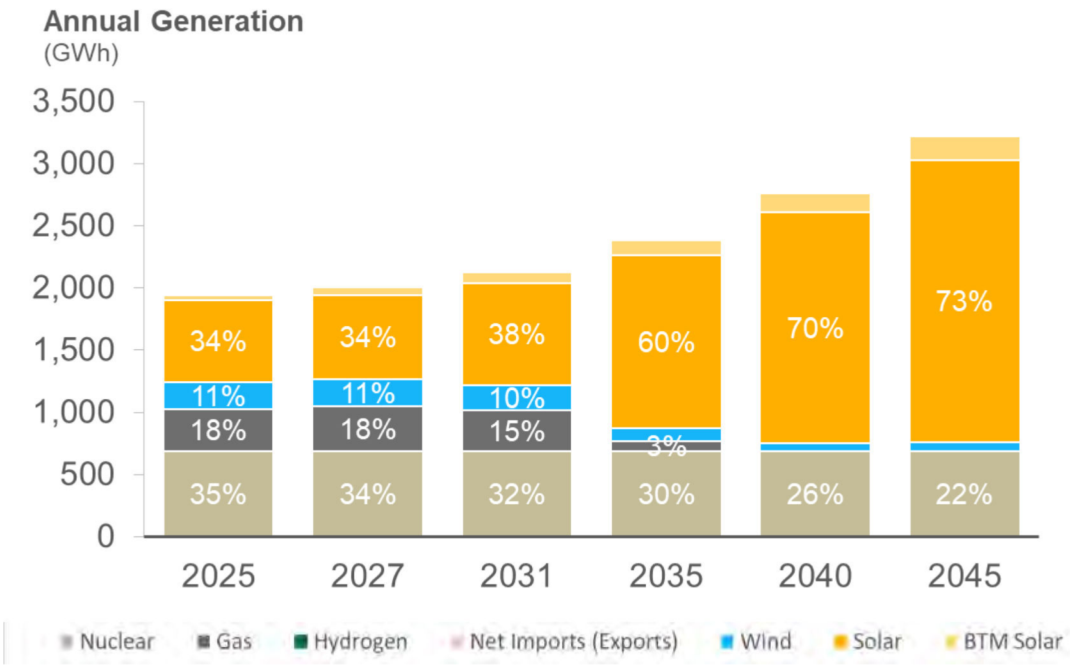
Figure 6-14. Annual Generation for NM Jurisdiction in SSP Case[41]



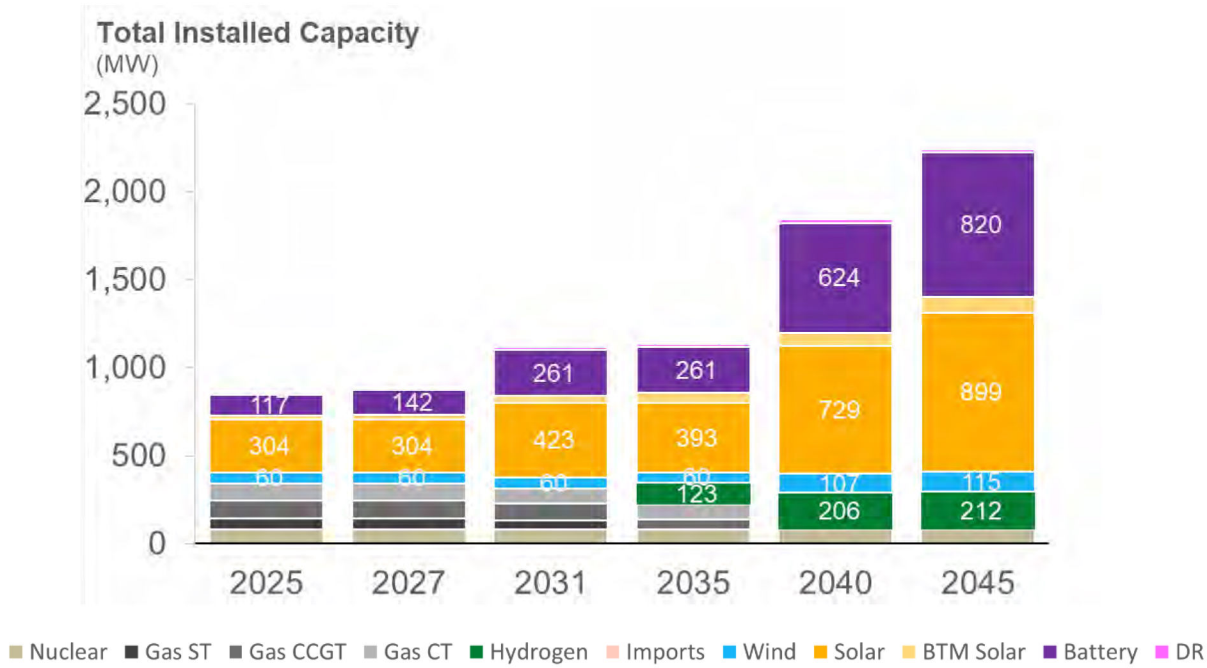
6.7 Separate System Planning (H2) Detailed Results

This section presents the year-by-year results for New Mexico in the Separate System Planning (H2) case (SSP H2). Dispatchable hydrogen generation significantly reduces the amount of solar and storage resources needed for reliability compared to the SSP case. It also adds more wind resources compared to the SSP case.

See Figure 6-15 for the total capacity for the New Mexico jurisdiction through 2045 in the SSP H2 case. In 2025, more than 300 MW of solar, 100 MW of storage, and 60 MW of wind capacity is allocated to the New Mexico jurisdiction. The capacity for each of these resources grows through 2045. Combustion turbines that can burn green hydrogen are added in later years to help the New Mexico system meet the 100% zero-carbon requirement while ensuring reliability at least cost. The capacity for these combustion turbines increases from approximately 120 MW in 2035 to more than 200 MW in 2040 and 2045.

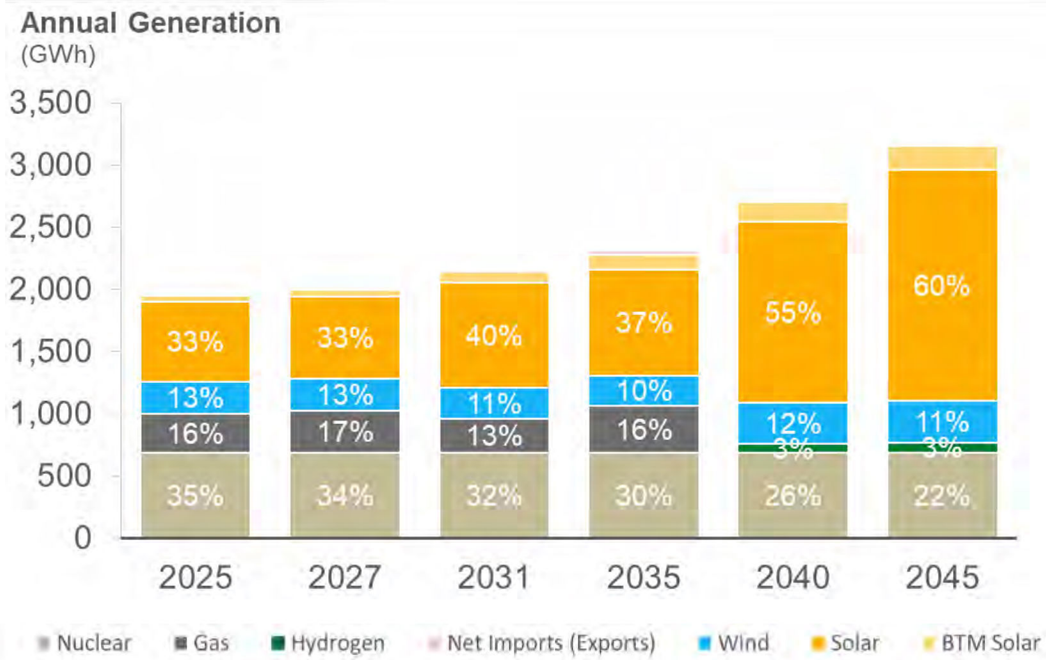
[41] The chart shows percentages for solar, wind, natural gas, and nuclear. This is the generation expressed as a percentage of total New Mexico load.

Figure 6-15. Capacity for NM Jurisdiction in SSP H2 Case



See Figure 6-16 for the annual generation for the New Mexico jurisdiction through 2045 in the SSP H2 case. In 2040 and 2045, when the 100% zero-carbon requirement is in effect, only renewable and zero-carbon resources serve New Mexico load. Solar, wind, and nuclear generation account for most of this generation. Generation from green hydrogen accounts for a small share of the total generation (approximately 3%). Because of the high cost to produce green hydrogen, the combustion turbines dispatch infrequently, only when other clean resources do not produce sufficient energy to serve load. They serve as a reliable source of back-up power and can supply zero-carbon generation when other zero-carbon resources aren't available to meet load.

Figure 6-16. Annual Generation for NM Jurisdiction in SSP H2 Case[42]



[42] The chart shows percentages for solar, wind, natural gas, and nuclear. This is the generation expressed as a percentage of total New Mexico load.

7 Sensitivity Analysis

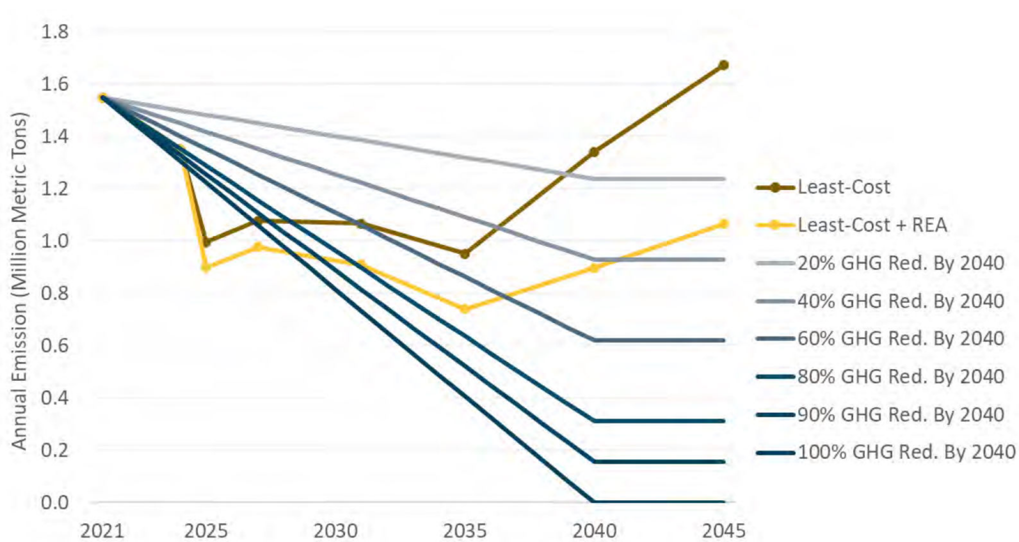
In addition to the REA cases, E3 performed analysis on several sensitivity cases to evaluate uncertainties in key planning assumptions and their impacts on the system portfolio. For each sensitivity case, E3 varied one or more inputs from the Least-Cost case and reoptimized for the period 2025-2045 to determine a new optimal portfolio. Any differences in the portfolio between the Least-Cost case and the sensitivity cases indicate the impact of the changes to planning assumptions. Sensitivity cases analyzed in this study include:

- Carbon reduction sensitivities
- Load and demand-side resource sensitivities
- Gas resource sensitivities
- Gas and carbon price sensitivities
- Technology cost sensitivity

7.1 Carbon Reduction Sensitivities

E3 assessed several greenhouse gas (GHG) reduction trajectories for the El Paso Electric system, ranging from 20% to 100% reductions by 2040 (see Figure 7-1). E3 first modeled the El Paso Electric system in 2021 to determine the emissions associated with serving retail load in this year. This emissions level serves as the baseline for calculating future emissions reductions under the different trajectories through 2040.

Figure 7-1. Emission Limits for Carbon Reduction Sensitivities



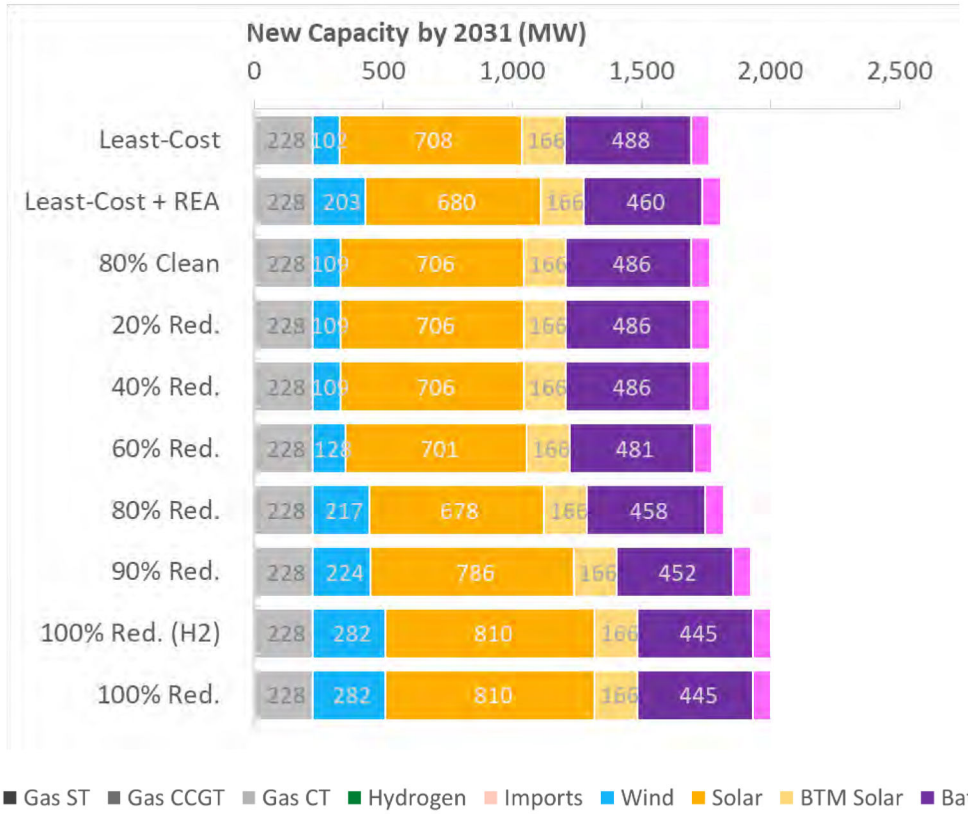
Modeling a range of carbon reduction trajectories serves two primary purposes. First, it helps inform how the cost of the EPE portfolio changes as a function of greenhouse reduction levels. This cost-carbon relationship can help guide future portfolio decisions. Second, there is a possibility that the federal government establishes carbon reduction requirements (or similar clean energy policies) that would require EPE to reduce emissions from the portfolio beyond levels that would result from existing state policies. These sensitivities, along with the carbon price sensitivities in Section 7.4, provide insights into how the portfolio could evolve under such policies.

The remainder of this section presents a summary of the results of the carbon reduction sensitivities, as well as a sensitivity that requires the portfolio to reach 80% zero-carbon energy by 2035 ("80% Clean").[43] The summary includes capacity and energy charts for 2031 and 2040, as well as a chart that illustrates the relationship between cost and carbon.

See Figure 7-2 for the cumulative resource additions through 2031. The portfolios in the 80% Clean and 20% to 60% Carbon Reduction sensitivities are similar to that of the Least-Cost case. This is because near-term renewable additions in the Least-Cost case already result in a reduction of carbon emissions in 2031 from the 2021 baseline emissions level. As shown in Figure 7-1 above, the Least-Cost case goes beyond the emissions reduction trajectory for the 60% Carbon Reduction sensitivity in 2031. Similarly, the 80% Carbon Reduction portfolio is similar to the Least-Cost Plus REA Resources case, as the latter achieves emissions reductions in 2031 that are very close to the trajectory for the 80% Carbon Reduction sensitivity. For the 90% and 100% reduction portfolios, more renewable resources are added to the system to further reduce emissions. These renewable resources also contribute to the reliability requirement and thus reduce some of the need for incremental storage capacity. Across all sensitivities, no new gas capacity is added by 2031 beyond Newman 6.

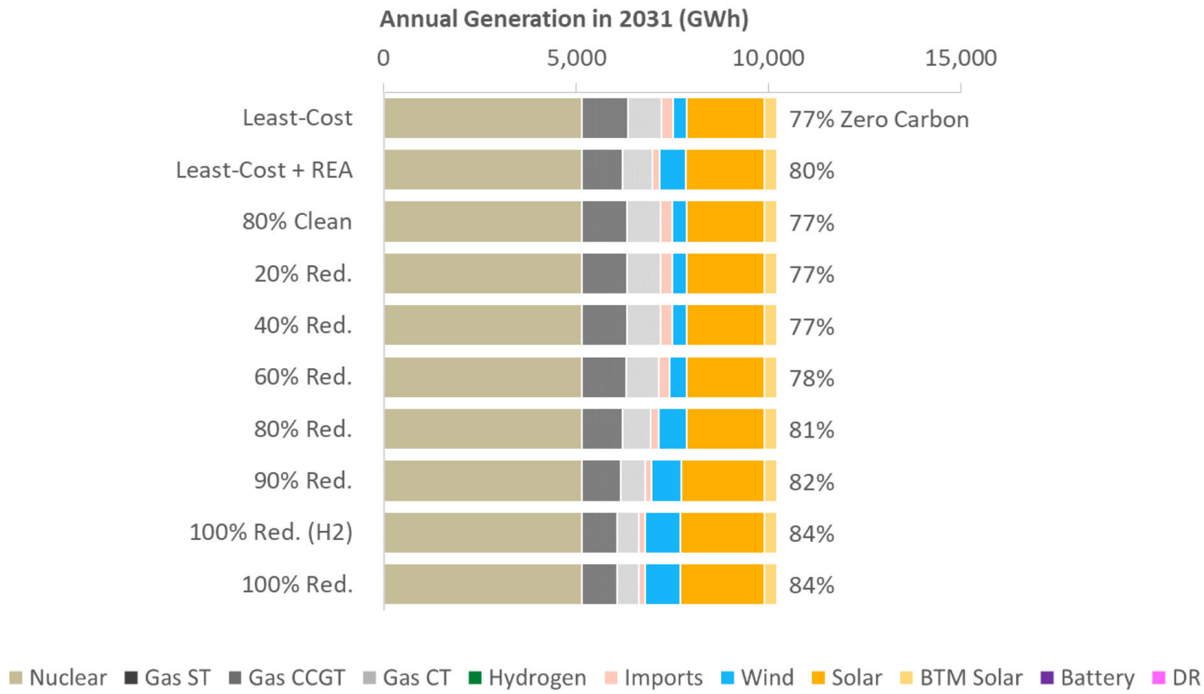
[43] E3 presented draft results for the carbon reduction sensitivities at the 2021 El Paso Electric Company Integrated Resource Plan Public Participation March 2021 Meeting. This report provides final results for the carbon reduction sensitivities.

Figure 7-2. Cumulative New Capacity by 2031 for Carbon Reduction Sensitivities



See Figure 7-3 for the annual generation mix in 2031. The shares of generation from zero-carbon energy sources in the 80% Clean and 20% to 60% Carbon Reduction cases are close to that of the Least-Cost case (77%). In the more stringent emission reduction sensitivities, which have more renewable resource additions, the percentage of zero-carbon energy increases to over 80%.

Figure 7-3. Annual Generation in 2031 for Carbon Reduction Sensitivities



See Figure 7-4 and Figure 7-5 for the cumulative resource additions through 2040. Figure 7-5 includes the most extreme sensitivity, 100% Carbon Reduction (no H_2). Compared to 2031, there is much more divergence in the resource portfolios in 2040 because the clean energy targets become binding in all sensitivities. As the stringency of the requirement increases, the resource portfolio has more renewable and storage resources, and less gas plant additions. At the 100% carbon reduction level, almost all additions beyond Newman 6 are renewable and storage resources. The large difference in resource additions between the two 100% Carbon Reduction sensitivities highlights the benefits of a clean, firm resource – in this study, hydrogen-powered plants – in achieving a fully decarbonized system. Without such a resource, supplying 100% zero-carbon energy while ensuring reliability across all hours requires a significant overbuild of renewable and storage resources.

Figure 7-4. Cumulative New Capacity by 2040 for Carbon Reduction Sensitivities

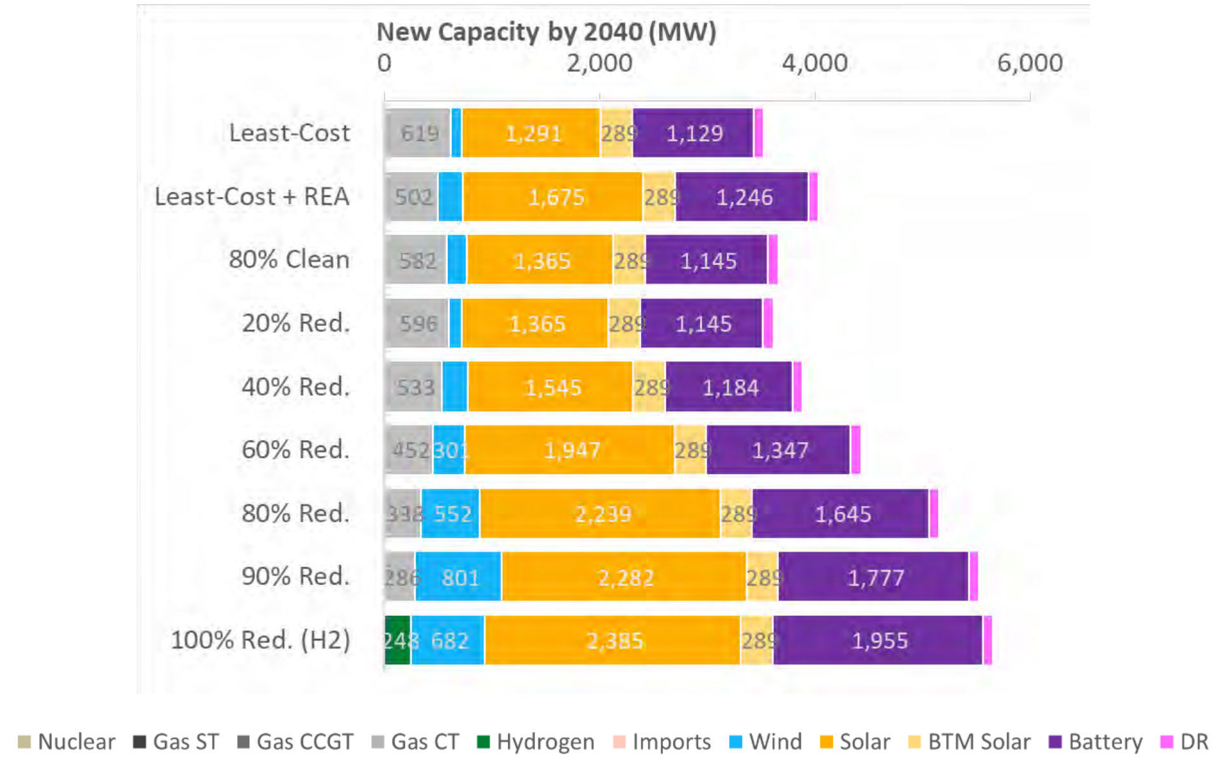
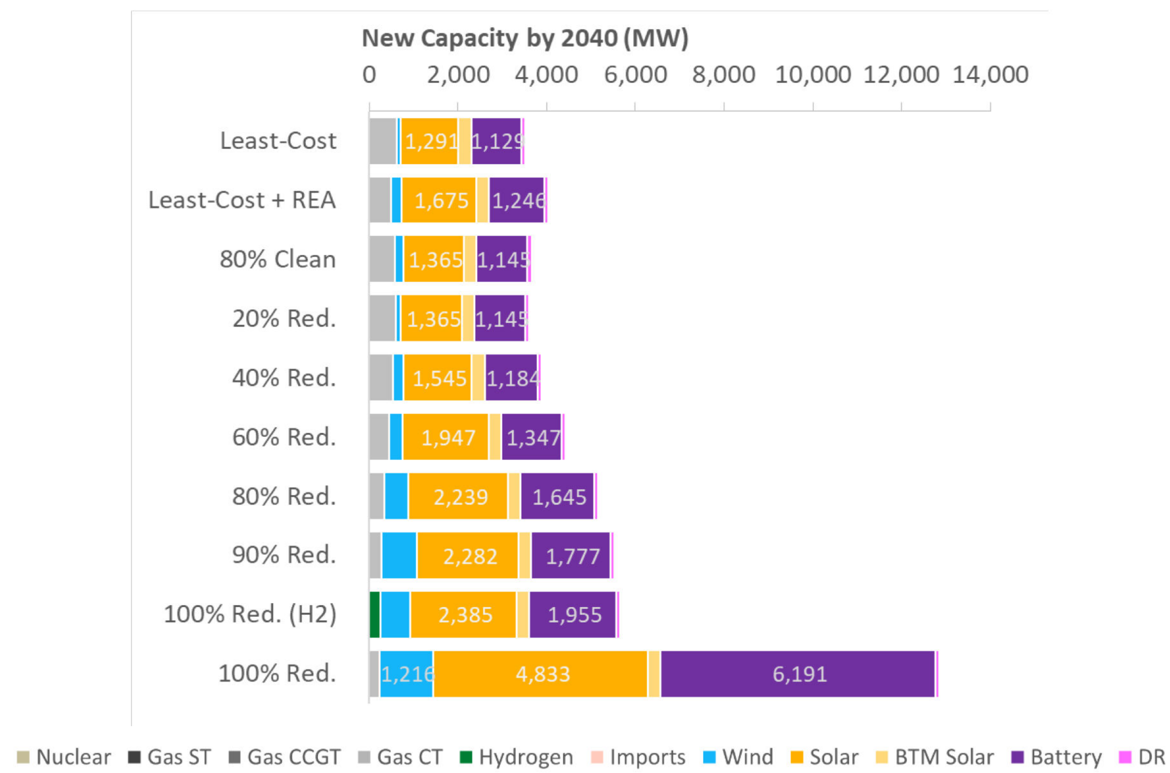
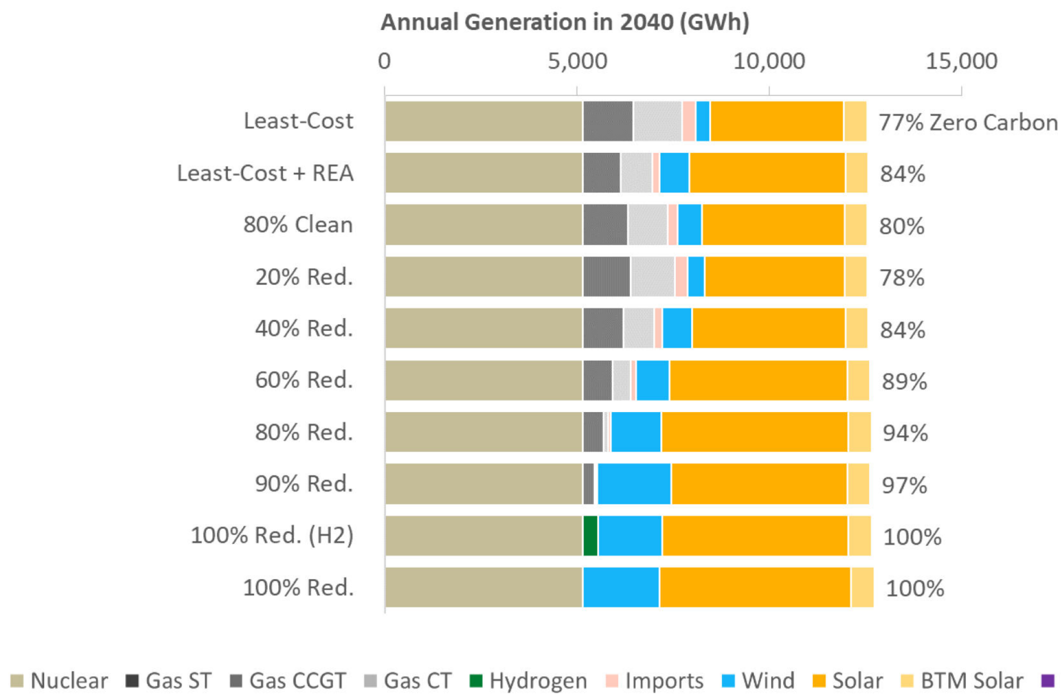


Figure 7-5. Cumulative New Capacity by 2040 for Carbon Reduction Sensitivities



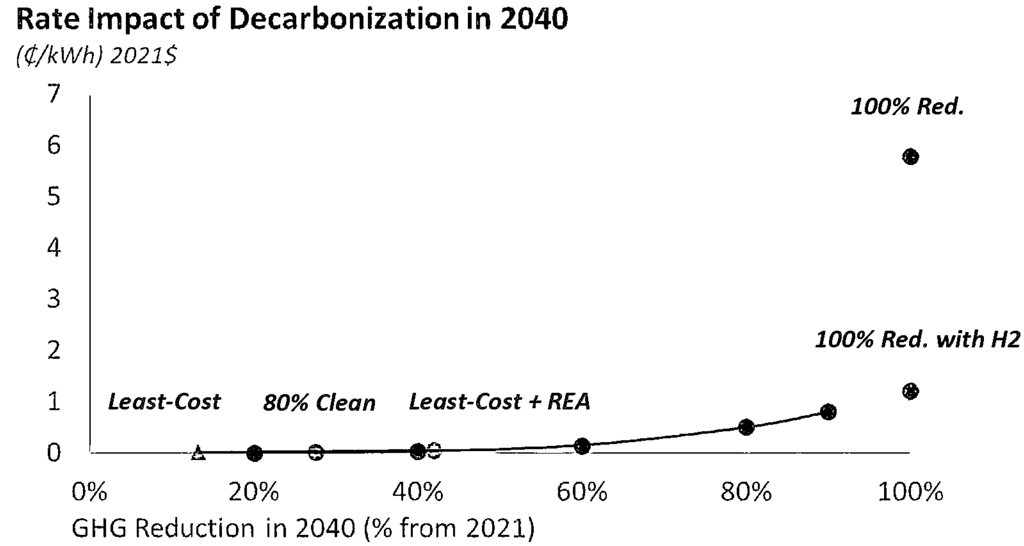
See Figure 7-6 for the annual generation mix in 2040 across carbon reduction sensitivities. Gas generation and market imports decline as the stringency of the targets increases. In the 100% Carbon Reduction (H_2) case, nuclear, wind, and solar resources make up most of the energy supply. Given the high cost of hydrogen, hydrogen-burning plants only dispatch when the system does not have sufficient energy supply from other resources and thus have low capacity factors. In the 100% Carbon Reduction (no H_2) sensitivity, the only resources available to serve load besides nuclear are wind and solar facilities.

Figure 7-6. Annual Generation in 2040 for Carbon Reduction Sensitivities



The cost of the EPE portfolio under these sensitivities is another important factor to consider. Figure 7-7 shows the incremental average system rate impact relative to the Least-Cost case, as well as the reduction in GHG emissions, for the above sensitivities in 2040. The Least-Cost case results in 13% GHG reductions. The 20% and 40% reduction sensitivities, 80% Clean, and Least-Cost Plus REA cases achieve higher GHG reduction levels with relatively small impacts to rates. Further emission reductions lead to higher rate impacts. The 90% Carbon Reduction sensitivity has an additional cost of 0.8 ₵/kWh. The rate impacts are higher still for the 100% Carbon Reduction sensitivities, with the rate impact for the sensitivity without hydrogen (5.8 ₵/kWh) being significantly higher than the rate impact for the sensitivity with hydrogen (1.2₵/kWh). As discussed above, the sensitivity without hydrogen results in significant overbuilds of renewable and storage resources to ensure reliability without firm generating capacity. This results in the large rate impact.

Figure 7-7. Incremental Rate Impact in 2040 for Carbon Reduction Sensitivities



7.2 Load and Demand-Side Resource Sensitivities

One key planning assumption that drives future resource needs is the load forecast. There are several uncertain factors within the load forecast, including end-use energy demand, distributed generation (DG) deployment levels, and demand-side management (DSM) deployment levels. Each of these factors is tested through the following sensitivities:

- **High Distributed Generation (DG)**
  EPE provided a high forecast for the deployment of DG, which is more than double the level in the Least-Cost case. Figure 7-8 *compares the DG levels in the high DG sensitivity versus the base assumption.*

- **High Demand-Side Management (DSM)**
  In the High DSM sensitivity, EPE assumed that smart thermostats gain market adoption faster than in the Least-Cost case and would ultimately rise to 60 MW of capacity rather than 50 MW (see Figure 7-9 *). This sensitivity also assumes a doubling of incremental energy efficiency levels compared with the base assumption (see* Figure 7-10 *).*

- **Low Load Growth** and **High Load Growth**
  EPE developed load forecasts for low and high load growth sensitivities. Figure 7-11 *and* Figure 7-12 *compare the load forecast for energy and demand, respectively, between the sensitivities and the base assumption.*

Load and demand-side resource forecasts beyond 2040 were assumed to have the same growth rate as that between 2039 and 2040. [44]

Figure 7-8. Distributed Generation Capacity in the High DG Sensitivity

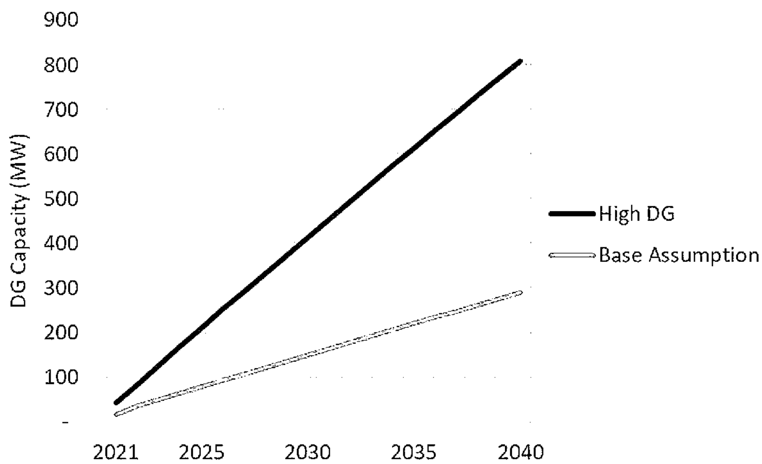
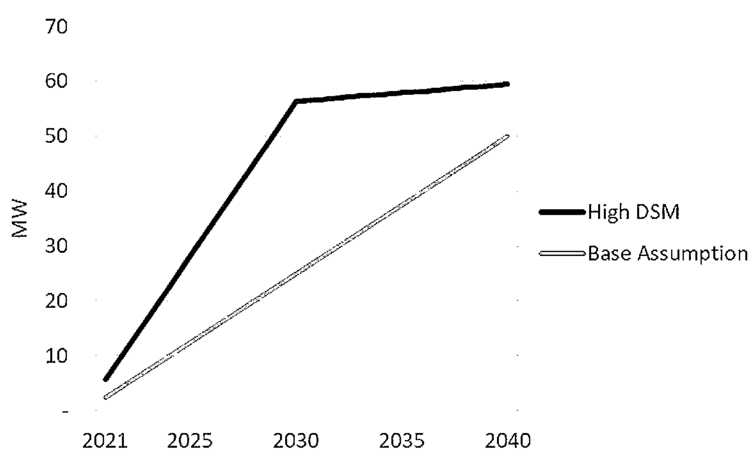


Figure 7-9. Smart Thermostat Capacity in the High DSM Sensitivity



[44] The capacity for smart thermostats remains constant at the 2040 level.

Figure 7-10. Incremental Energy Efficiency in the High DSM Sensitivity

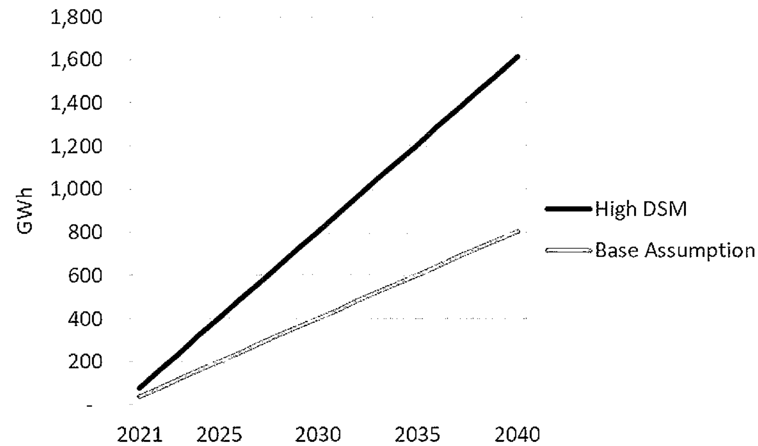
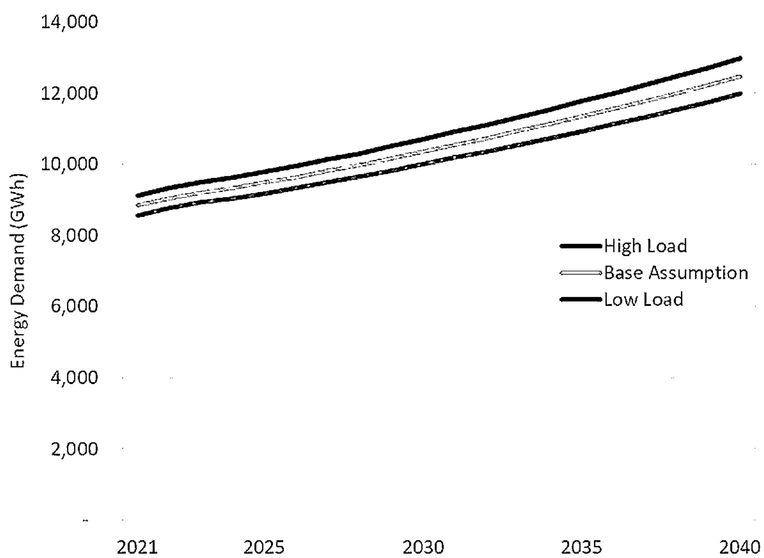
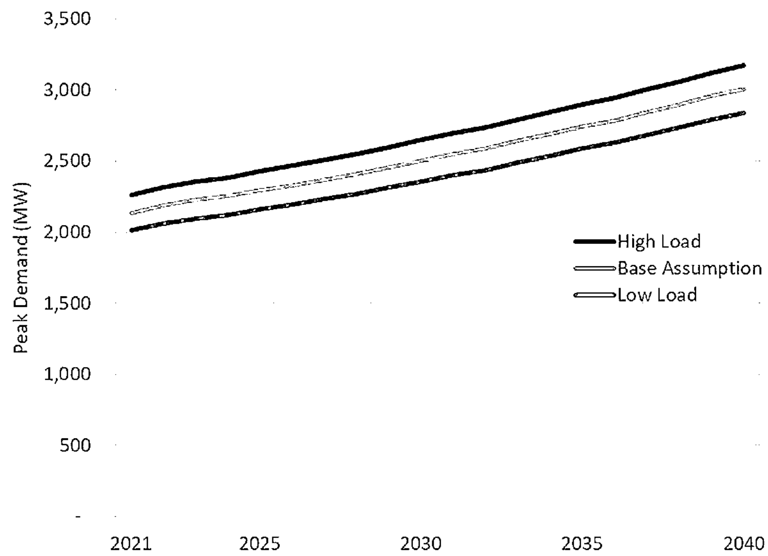


Figure 7-11. Native System Load Forecast[45] for Energy in Load Sensitivities



[45] Native system forecast does not include the impact of energy efficiency (EE), distributed generation (DG), and electric vehicles (EV). These components are accounted for separately and do not change in the Low Load or High Load sensitivities.

Figure 7-12. Native System Load Forecast[45] for Demand in Load Sensitivities



See Figure 7-13 and Figure 7-14 for the cumulative resource additions through 2031 and 2040, respectively. In the High DG sensitivity, the additional DG in the system displaces the need for some utility-scale solar, but otherwise has a similar portfolio to that of the Least-Cost case. In the High DSM and Low Load sensitivities, reduced load across all hours leads to less capacity additions across all resources.[46] By contrast, the higher demand in the High Load sensitivity leads to more capacity additions across all resources.

See Figure 7-15 and Figure 7-16 for the annual generation mix in 2031 and 2040, respectively. In the high DG sensitivity, the generation mix is almost the same as the Least-Cost case, as DG replaces utility-scale solar, which has a similar production profile. In the High DSM and Low Load sensitivities, the percentage of zero-carbon energy is lower than that in the Least-Cost case because of lower renewable energy levels and higher gas dispatch. The High Load sensitivity has a slightly higher zero-carbon energy share than the Least-Cost case in 2031 due to more renewable resources in the near-term and a slightly lower clean percentage in 2040 as more gas is added.

[46] BTM solar capacity remains at the levels that are forecast by EPE and does not vary in these sensitivities.

Figure 7-13. Cumulative New Capacity by 2031 for Load and Demand-Side Resource Sensitivities

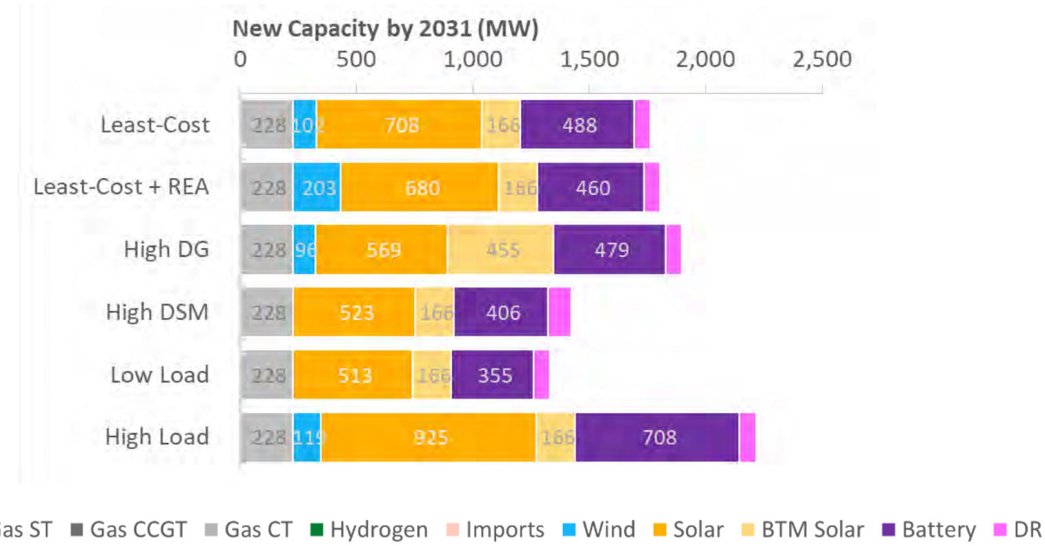


Figure 7-14. Cumulative New Capacity by 2040 for Load and Demand-Side Resource Sensitivities

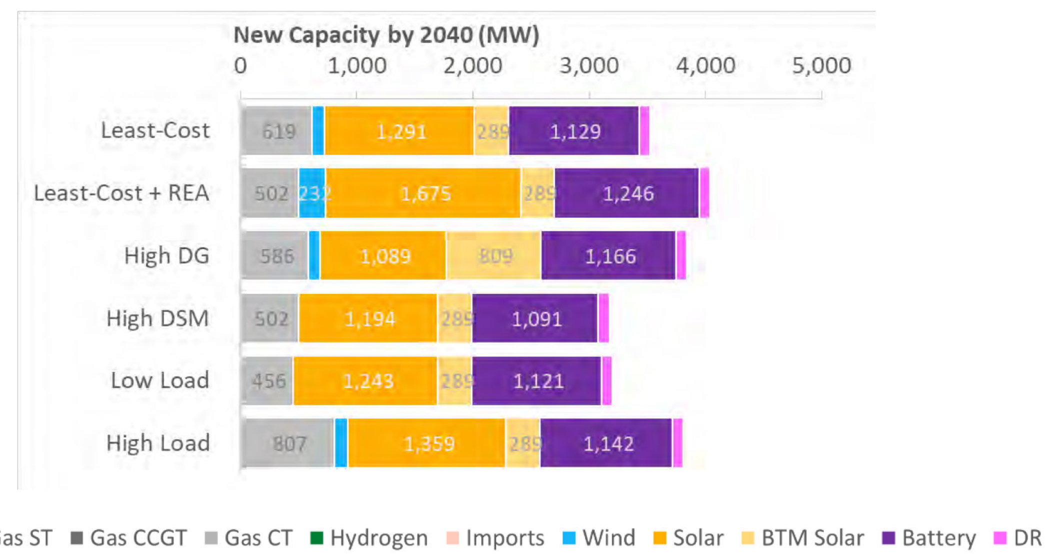


Figure 7-15. Annual Generation in 2031 for Load and Demand-Side Resource Sensitivities

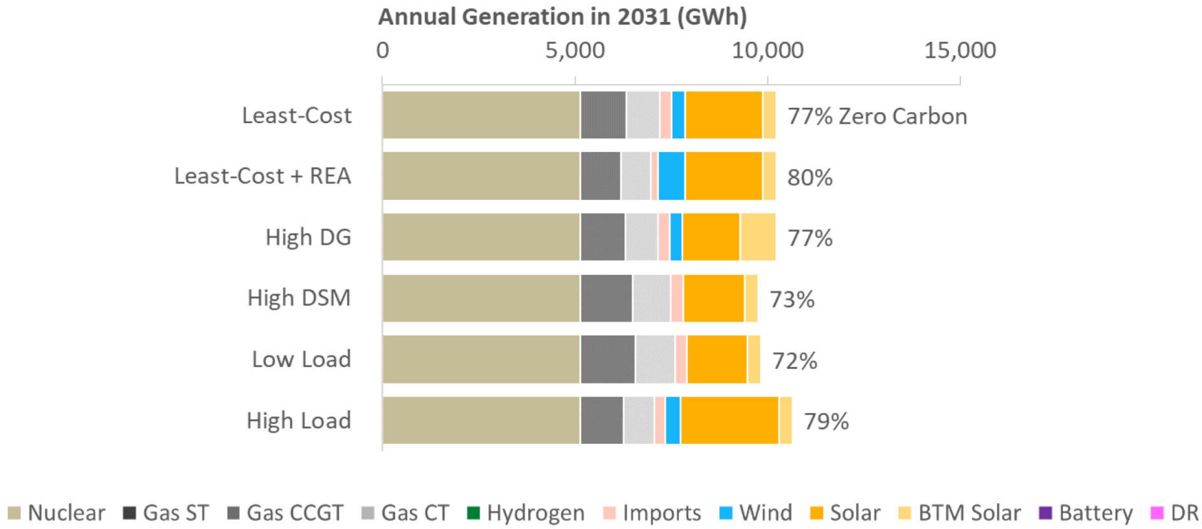
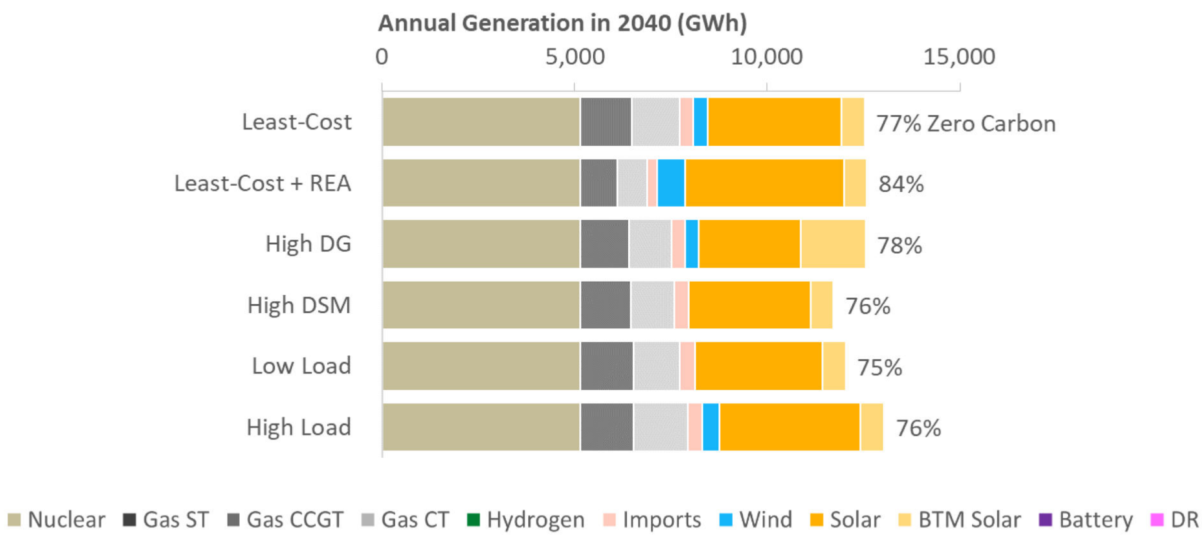


Figure 7-16. Annual Generation in 2040 for Load and Demand-Side Resource Sensitivities



7.3 Gas Resource Sensitivities

Across the REA cases, existing and new gas resources play an important role in ensuring reliability for the overall system. E3 analyzed two sensitivities for gas resource availability to understand the implications of not having some gas resources available to the portfolio:

- **No Lifetime Extensions**
  In the Least-Cost case, the lifetimes for Newman units 1, 3, and 4 are extended by five years. These plant extensions reduce the need for new capacity in the near term. The No Lifetime Extensions sensitivity does not allow for these lifetime extensions. Given the uncertainty in plant conditions and maintenance costs going forward, this sensitivity can help EPE assess which resources are needed without these extensions.

- **No New Gas**
  After the addition of the Newman 6 unit, the portfolio cannot include any new natural gas plant capacity, including capacity that would otherwise serve Texas customers.

See Figure 7-17 and Figure 7-18 for the cumulative resource additions through 2031 and 2040, respectively. In 2031, the No Extension sensitivity has more renewable, storage, and gas additions than the Least-Cost case to make up for the reduction in capacity from the units that retire earlier. However, by 2040, the two portfolios converge, as the gas extensions in the Least-Cost case do not go beyond 2031. For the No New Gas sensitivity, more renewable and storage resources are added to the system than the Least-Cost case to meet load growth and reliability requirements. This is especially evident by the year 2040. Without the option to add gas capacity, the No New Gas sensitivity relies on renewable and storage resources to satisfy the PRM, and these resources' contributions decline with penetration (per the ELCC analysis).

Figure 7-17. Cumulative New Capacity by 2031 for Gas Resource Sensitivities

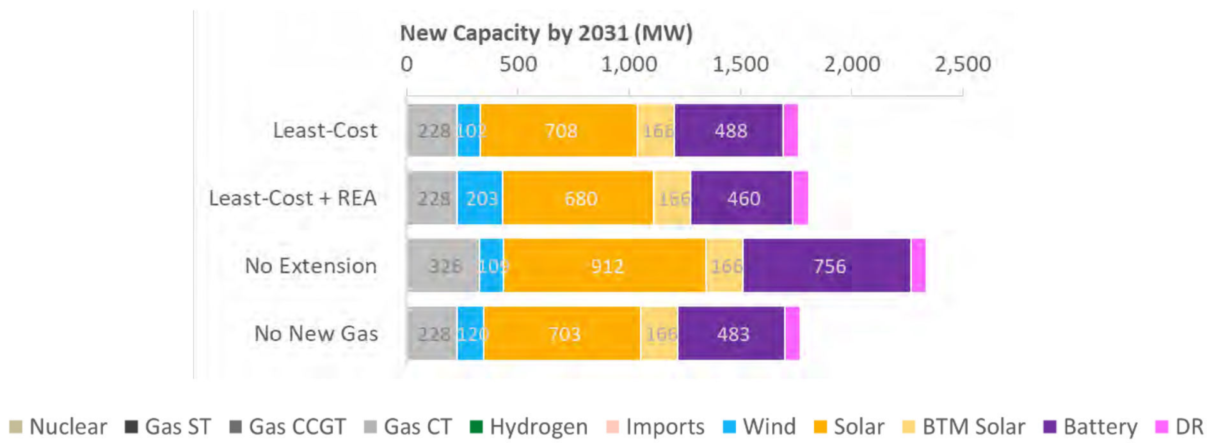
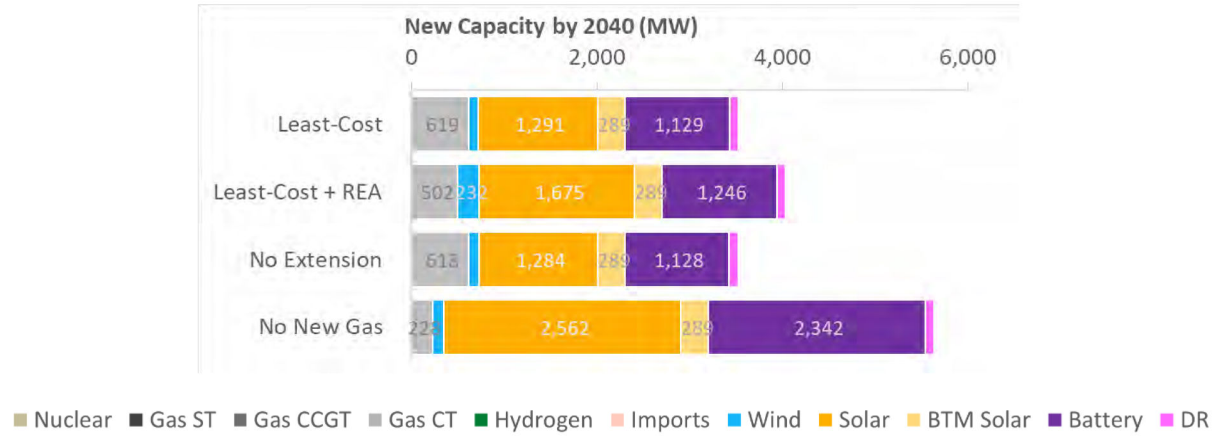


Figure 7-18. Cumulative New Capacity by 2040 for Gas Resource Sensitivities



See Figure 7-19 and Figure 7-20 for the annual generation mix in 2031 and 2040, respectively. The No Extension sensitivity has a higher percentage of zero-carbon energy than the Least-Cost case in 2031 because of larger near-term renewable additions. However, after the extension period, the generation mix is similar. The No New Gas sensitivity has a much greater share of zero-carbon energy in 2040 given the large amount of renewable resources on the system.

Figure 7-19. Annual Generation in 2031 for Gas Resource Sensitivities

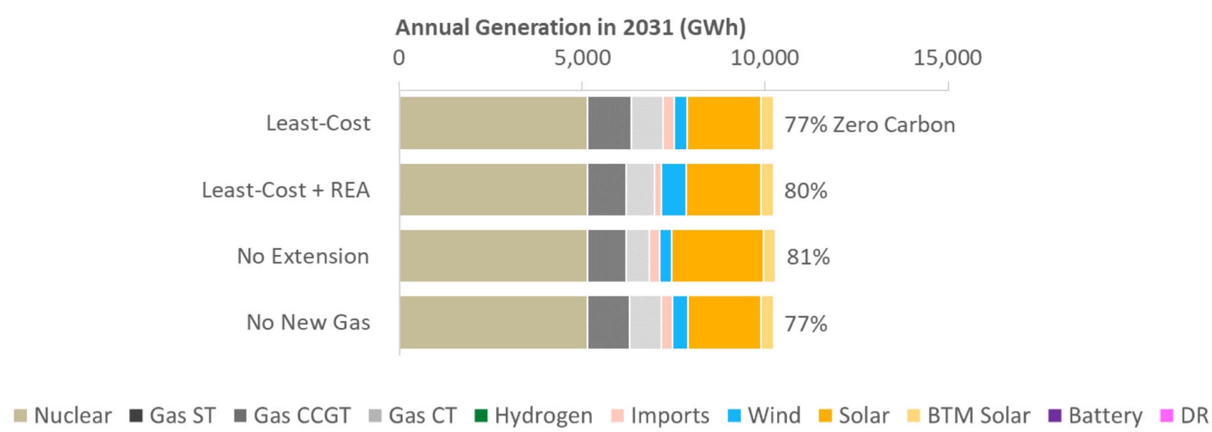
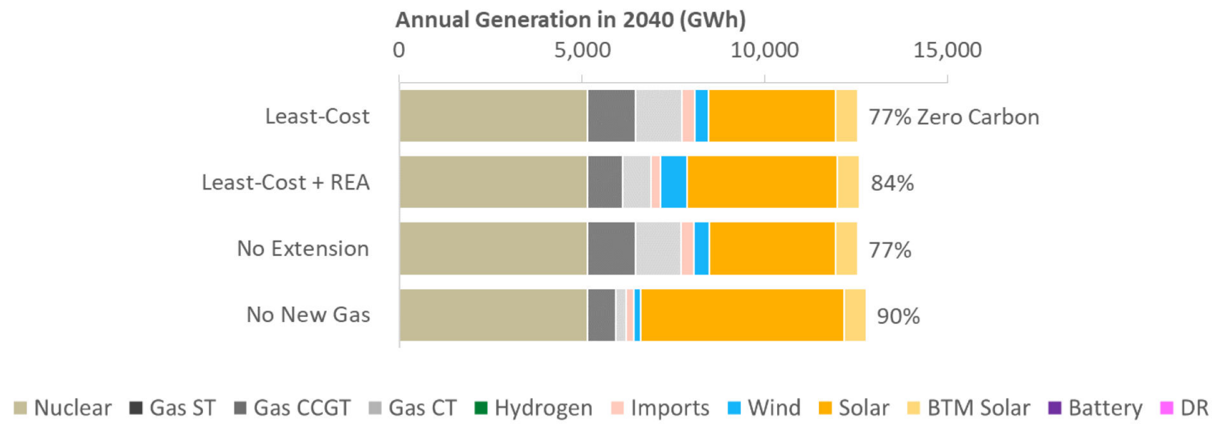
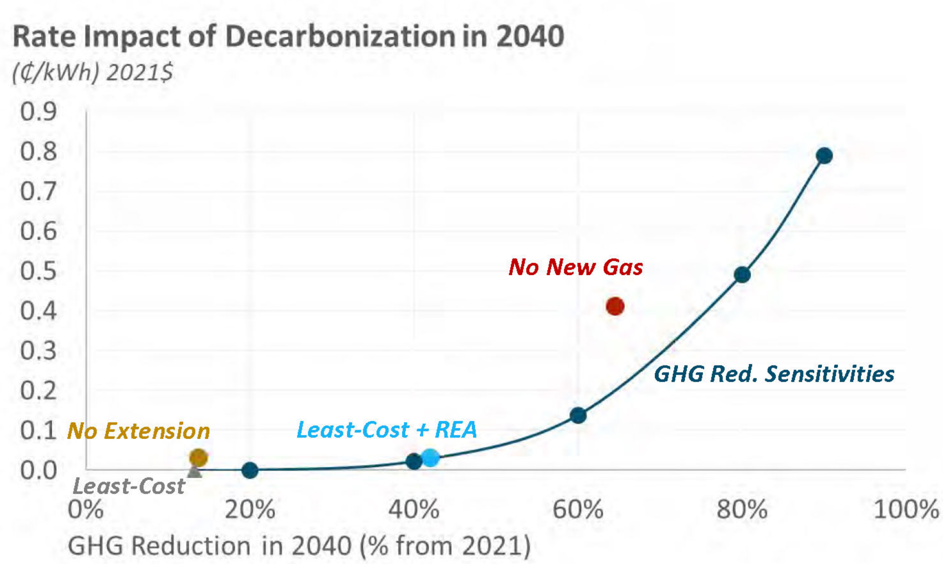


Figure 7-20. Annual Generation in 2040 for Gas Resource Sensitivities



See Figure 7-21 for the incremental rate impact of the gas resource sensitivities relative to the Least-Cost case in 2040. The No Extension sensitivity achieves the same level of carbon reductions as the Least-Cost case because they converge by this year. However, the No Extension sensitivity has slightly higher costs than the Least-Cost case because some of the renewable and storage resources in the No Extension sensitivity come online in earlier years when the resource costs are higher. The No New Gas sensitivity has a cleaner portfolio but also a higher cost than the Least-Cost case due to the overbuild of renewable and storage resources to displace firm gas resources available to the Least-Cost case. Moreover, the No New Gas sensitivity does not compare favorably to the cost-carbon relationship that was identified in the Carbon Reduction sensitivities that allowed for new gas plant additions.

Figure 7-21. Incremental Rate Impact in 2040 for Gas Resource Sensitivities



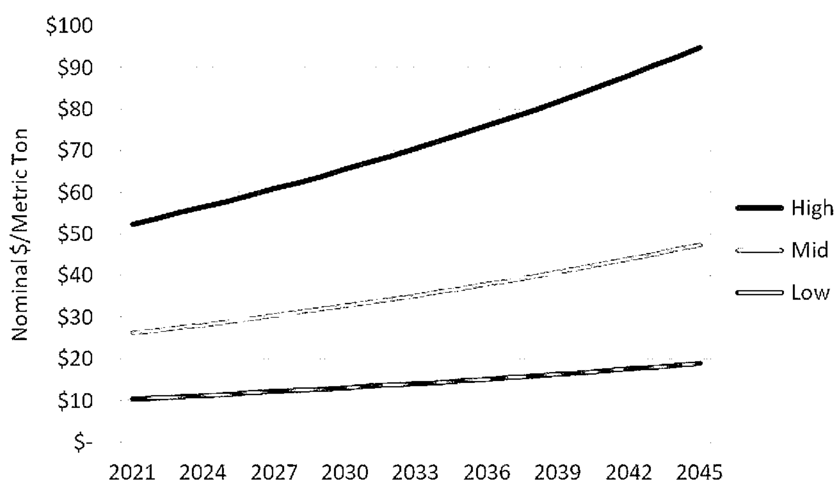
7.4 Gas and Carbon Price Sensitivities

The future market price of natural gas is uncertain. Historical gas prices are volatile, making future projections challenging. E3 tested a high gas price level. In addition, E3 tested different carbon price levels, which reflect the potential for future policies that impose a cost on emitting carbon dioxide from power plants. E3 analyzed four price sensitivities in total related to carbon or gas pricing:

- **Low / Mid / High Carbon Price**
  The New Mexico Public Regulation Commission has published carbon emission prices that should be considered in IRPs. Figure 7-22 *shows the low, mid, and high carbon price trajectories. Three sensitivity cases were developed by performing capacity expansion under these different carbon prices. The base assumption in the Least-Cost case is that there is not a price on carbon in the future.*

- **High Gas Price**
  Gas prices are 15% higher than those in the Least-Cost Case.

Figure 7-22. Carbon Price Sensitivities



See Figure 7-23 and Figure 7-24 for the cumulative resource additions through 2031 and 2040, respectively. See Figure 7-25 and Figure 7-26 for the annual generation mix in 2031 and 2040, respectively. Introducing carbon prices and increasing gas prices both make gas plant operations more expensive. As a result, the gas and carbon price sensitivities have more renewable resources and less new gas resources in the portfolio than the Least-Cost case. The generation mix also becomes cleaner in these sensitivities as the cost of burning gas is higher than the Least-Cost case. At the price levels tested in these sensitivities, the carbon price sensitivities have a larger impact on the portfolio. However, if higher gas prices were tested, the magnitude of the portfolio changes would increase commensurately.

Figure 7-23. Cumulative New Capacity by 2031 for Gas and Carbon Price Sensitivities

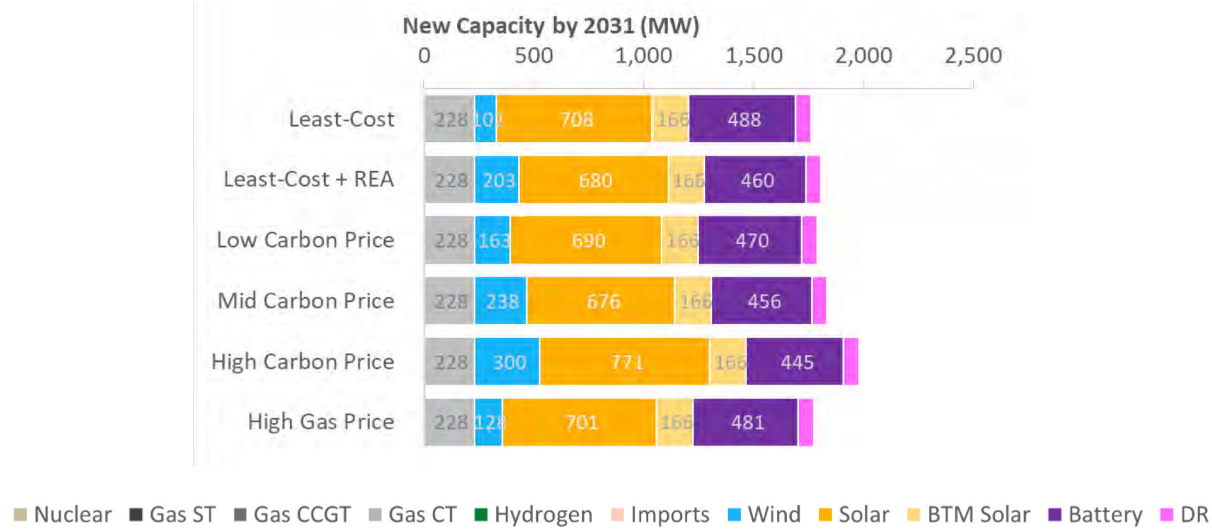


Figure 7-24. Cumulative New Capacity by 2040 for Gas and Carbon Price Sensitivities

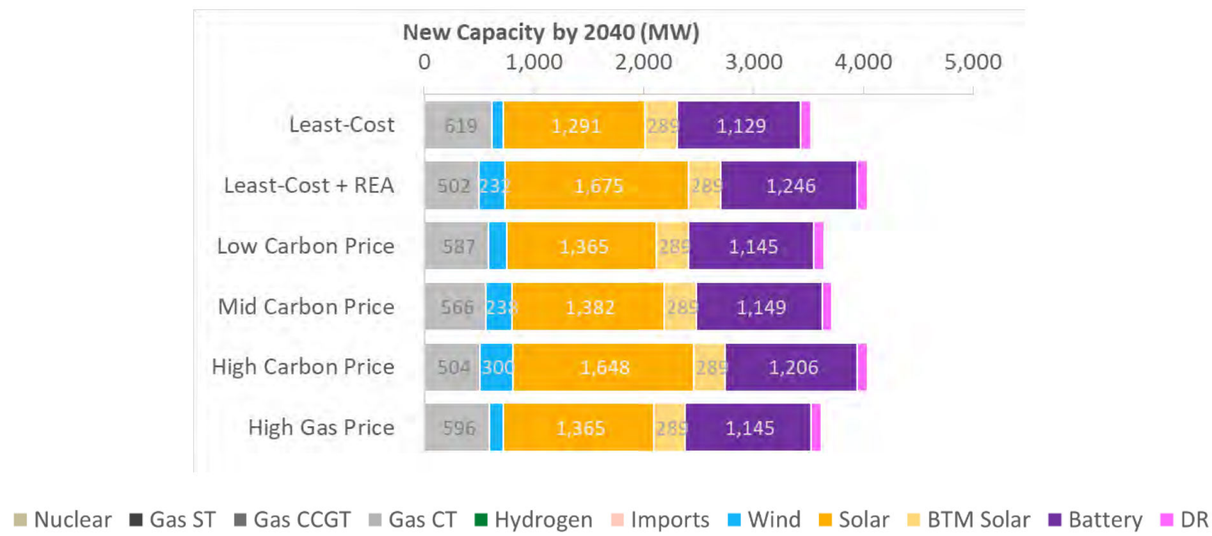


Figure 7-25. Annual Generation in 2031 for Gas and Carbon Price Sensitivities

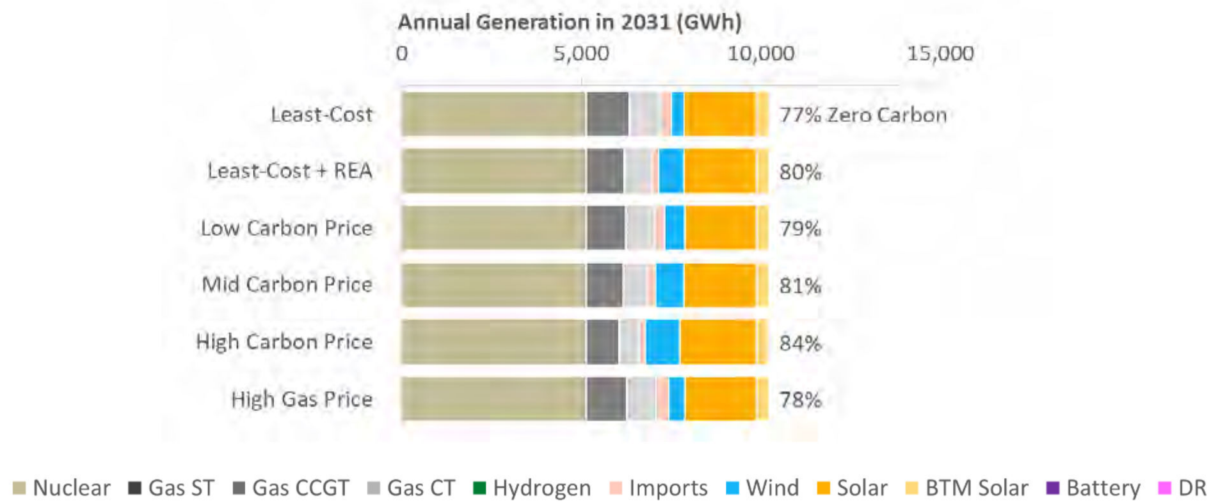
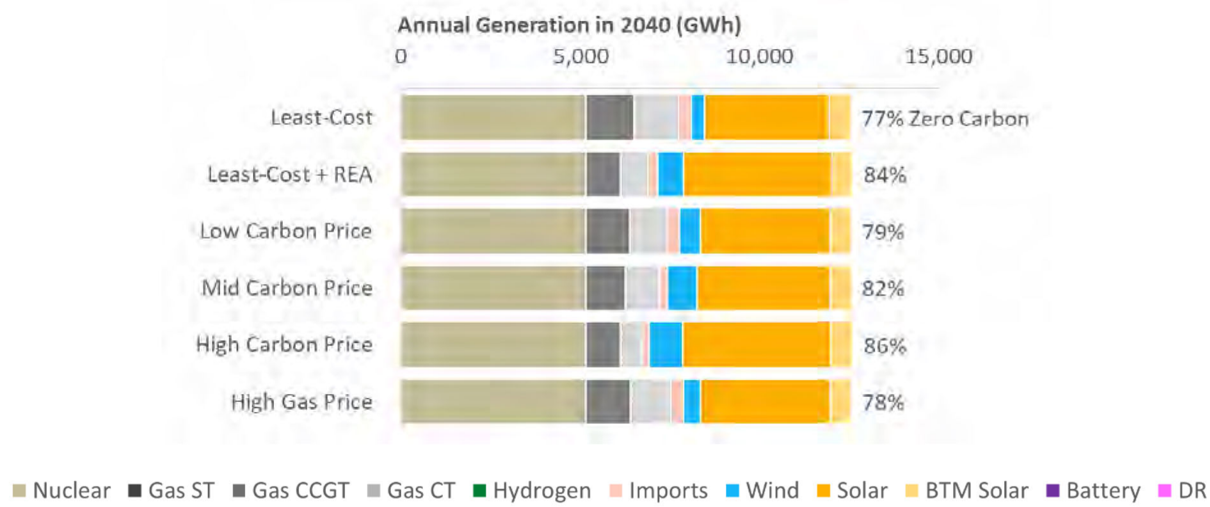


Figure 7-26. Annual Generation in 2040 for Gas and Carbon Price Sensitivities



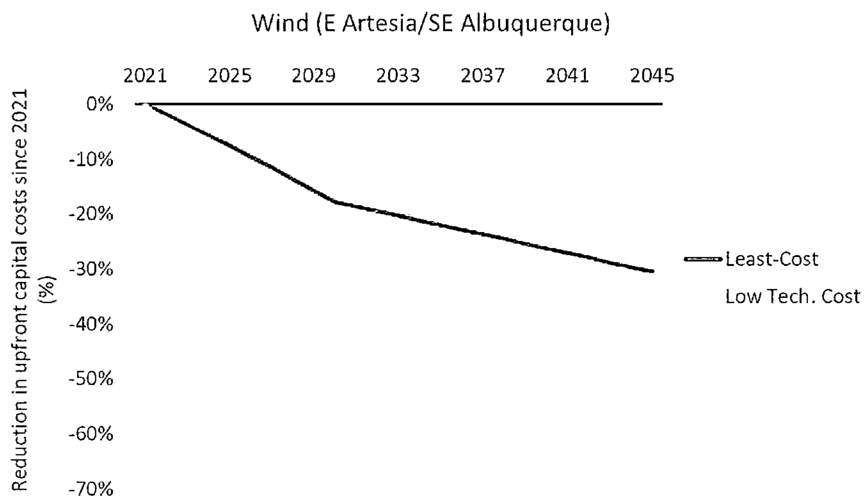
7.5 Technology Cost Sensitivity

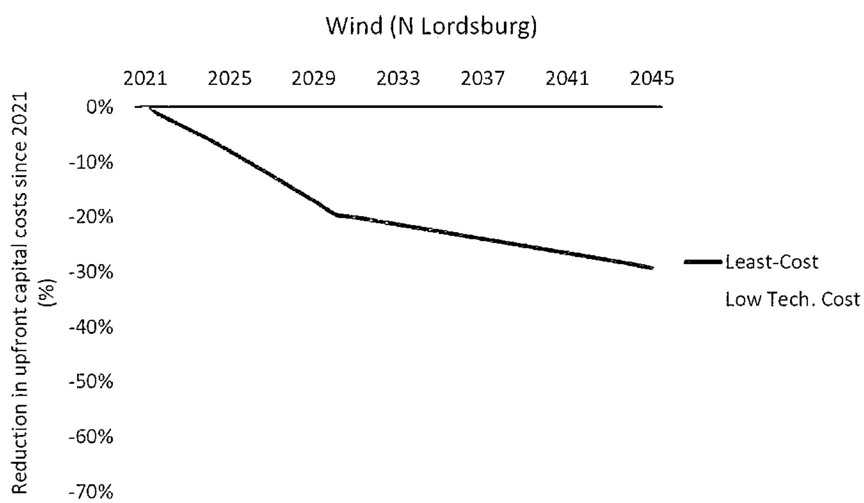
The deployment levels of different technologies within an optimal portfolio depend on many factors, but one of the most important is the cost of the technology. In recent years, the cost of renewable and storage resources has fallen dramatically. Under base assumptions, there are substantial further cost declines through the IRP planning horizon,[47] but these cost declines are uncertain. Costs could decline more slowly or more quickly than anticipated. E3 assessed a Low Technology Cost sensitivity, which has renewable and

[47] See Appendix A: Candidate Resource Assumptions for renewable and storage cost decline assumptions.

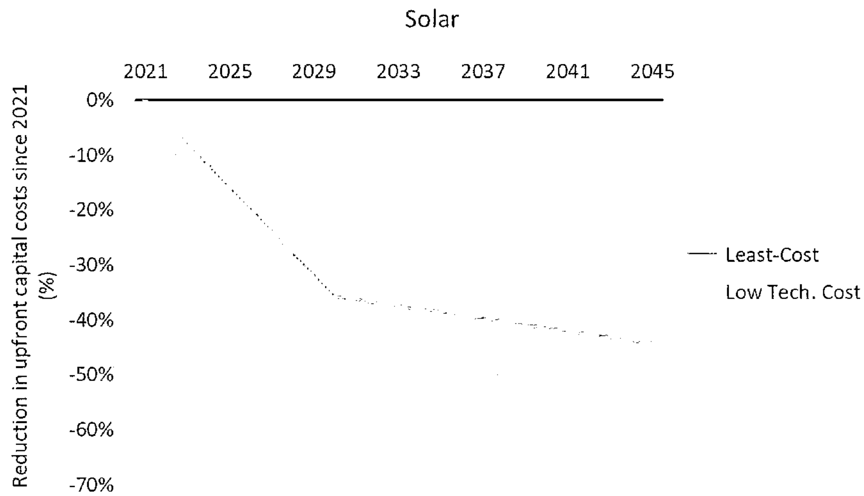
storage costs declining more quickly than under the base assumptions.[48] Figure 7-27 shows the change in resources costs by technology.

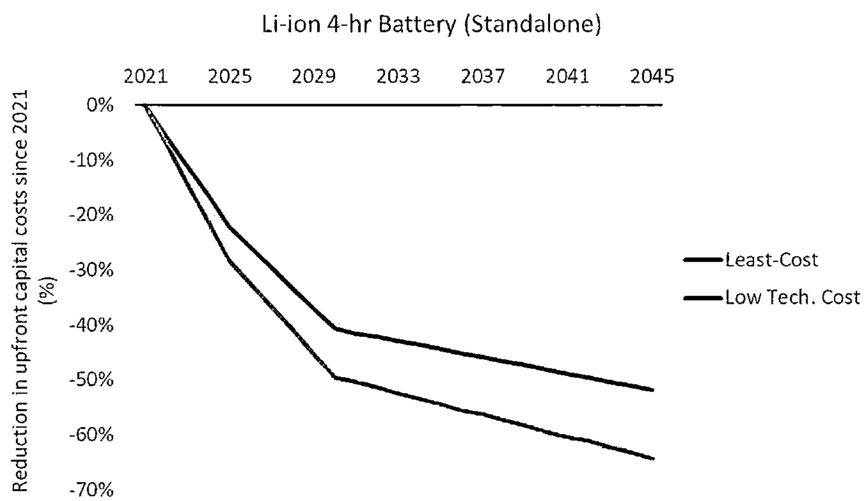
Figure 7-27. Cost Reductions in the Low Technology Cost Sensitivity

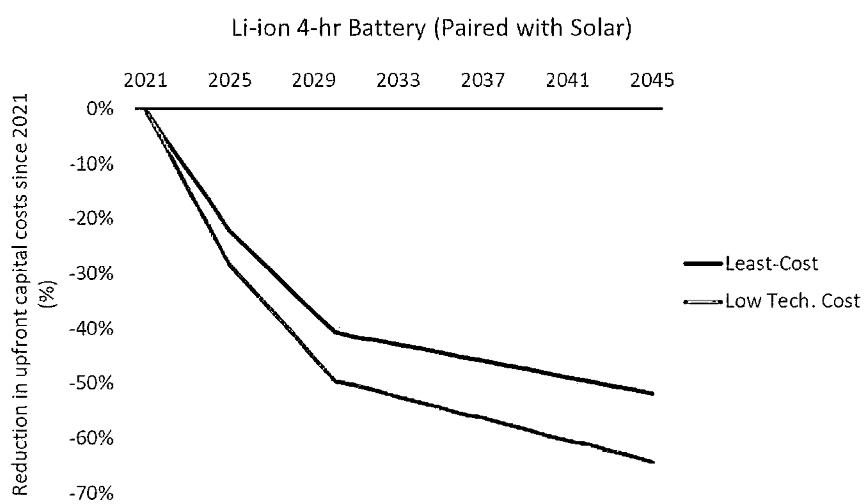




[48] The cost declines for the Low Technology Cost sensitivity are based on the "Advanced" trajectory from the NREL ATB, while the cost declines for the Least-Cost case are based on the "Moderate" trajectory from the NREL ATB.


Solar
2021 2025 2029 2033 2037 2041 2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost


Li-ion 4-hr Battery (Standalone)
2021 2025 2029 2033 2037 2041 2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost


Li-ion 4-hr Battery (Paired with Solar)
2021 2025 2029 2033 2037 2041 2045
0%
-10%
-20%
-30%
-40%
-50%
-60%
-70%
Reduction in upfront capital costs since 2021 (%)
Least-Cost
Low Tech. Cost

See Figure 7-28 and Figure 7-29 for the cumulative resource additions through 2031 and 2040, respectively. Lower technology costs make renewable and storage resources more economical, and thus the Low Technology Cost sensitivity has slightly more renewable additions and less gas additions than the Least-Cost portfolio. The resulting zero-carbon energy levels are also higher in the Low Technology Cost sensitivity (see Figure 7-30 and Figure 7-31). Between the renewable resources, the increase in wind capacity is higher than that of solar due to larger cost reductions.

Figure 7-28. Cumulative New Capacity by 2031 for Low Technology Cost Sensitivity

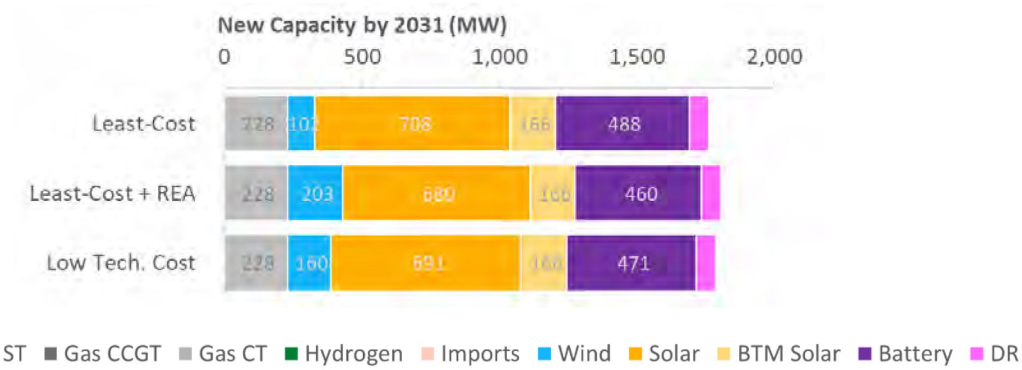


Figure 7-29. Cumulative New Capacity by 2040 for Low Technology Cost Sensitivity

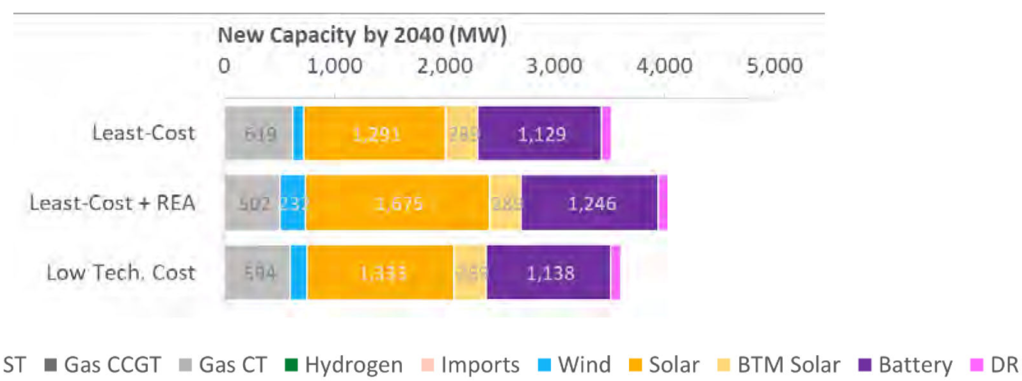


Figure 7-30. Annual Generation in 2031 for Low Technology Cost Sensitivity

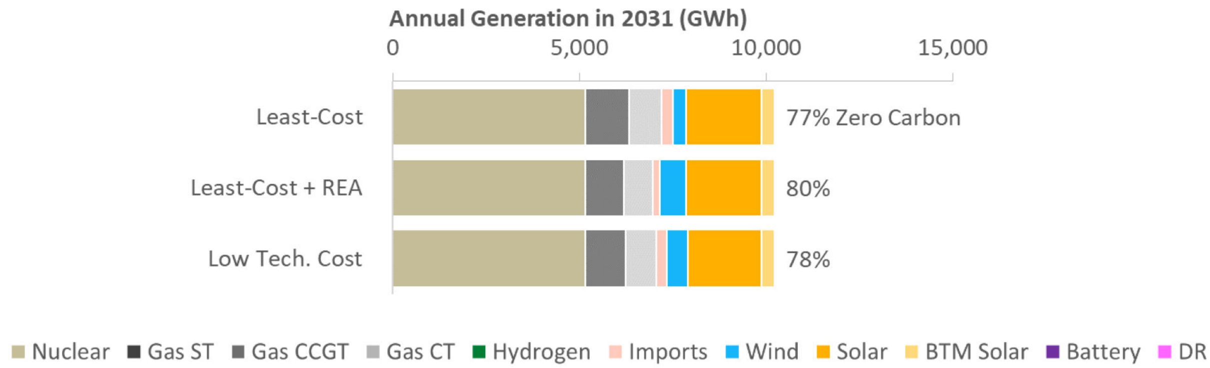
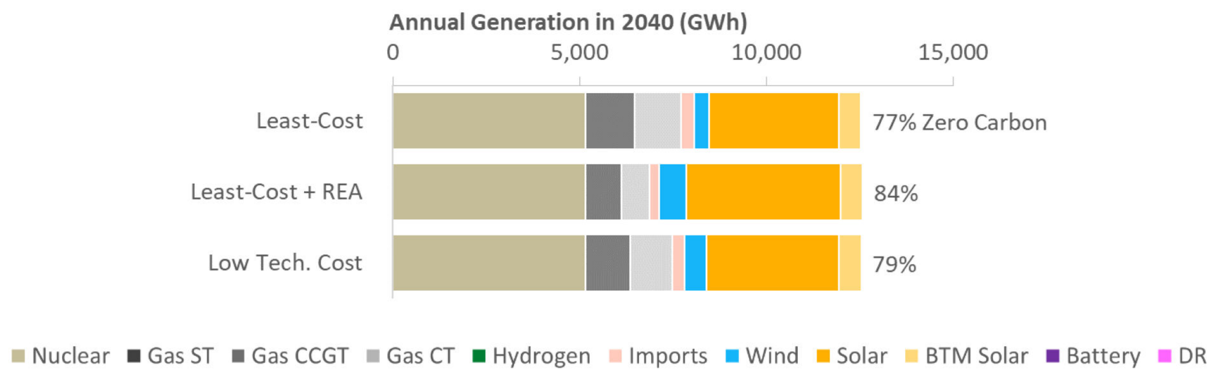


Figure 7-31. Annual Generation in 2040 for Low Technology Cost Sensitivity



8 Appendix A: Candidate Resource Assumptions

This appendix provides the assumptions for all candidate resource options that are considered in the resource portfolio optimization.

Table 8-1 provides the financial life for each resource. This is the period over which all costs for a project must be recovered. For modeling purposes, E3 assumes that gas projects would be financed by El Paso Electric and that renewable, storage, and nuclear projects would be financed by a third party and made available to El Paso Electric via power purchase agreements (PPAs) or tolling agreements.[49] This is a modeling assumption and does not necessarily reflect future financing and ownership structures.

Table 8-1. Financial Life (years)

Resource	Financial Life
Solar	30
BTM Solar	30
Wind	30
Geothermal	25
Biomass	20
Standalone Batteries	20
Paired Batteries	20
Gas Peaker	40
Nuclear (SMR)	30

Table 8-2 provides the upfront capital cost and Table 8-3 provides the fixed operations and maintenance (O&M) cost for each resource over time. E3 utilized the 2020 Annual Technology Baseline (ATB) from the National Renewable Energy Laboratory (NREL)[50] to develop cost assumptions for renewable, gas peaker, and nuclear resources. E3 utilized the Levelized Cost of Storage Version 6.0 report from Lazard[51] to develop cost assumptions for storage resources and applied a cost decline curve over time using data from the NREL ATB. For utility-scale solar resources, E3

[49] A tolling agreement is an agreement under which one entity pays another entity for the rights to utilize and dispatch a power plant to generate electricity.
[50] https://atb.nrel.gov/
[51] https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/

adjusted the upfront capital cost downward so that the levelized cost would align more closely with recent solar power purchase agreement (PPA) pricing.

Table 8-2. Upfront Capital Cost ($/kW) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	900	858	815	773	730	688	681	675	669	663	657	651	645	639	633	626	620	614	608	602	596
BTM Solar	1,693	1,607	1,521	1,435	1,350	1,264	1,249	1,234	1,220	1,205	1,190	1,175	1,161	1,146	1,131	1,117	1,102	1,087	1,072	1,058	1,043
Wind (Artesia/ABQ)[52]	1,463	1,431	1,399	1,367	1,333	1,299	1,286	1,273	1,260	1,247	1,234	1,220	1,207	1,194	1,180	1,167	1,153	1,140	1,126	1,113	1,099
Wind (Lordsburg) [53]	1,785	1,743	1,700	1,655	1,609	1,561	1,549	1,537	1,525	1,512	1,500	1,488	1,475	1,463	1,450	1,437	1,424	1,411	1,398	1,385	1,372
Geothermal	8,545	8,451	8,358	8,265	8,172	8,080	8,040	7,999	7,959	7,920	7,880	7,841	7,801	7,762	7,724	7,685	7,647	7,608	7,570	7,532	7,495
Biomass	4,499	4,482	4,464	4,447	4,429	4,407	4,385	4,363	4,339	4,321	4,301	4,275	4,255	4,234	4,209	4,184	4,166	4,142	4,121	4,100	4,081
Standalone Batteries	786	749	712	674	637	599	591	585	576	570	562	553	547	539	533	524	516	510	501	495	487
Paired Batteries	726	691	657	622	588	553	545	540	532	527	519	511	505	497	492	484	476	471	463	457	449
Gas Peaker	1,223	1,214	1,205	1,198	1,194	1,188	1,183	1,178	1,171	1,167	1,164	1,159	1,156	1,153	1,149	1,145	1,143	1,139	1,136	1,133	1,130
Nuclear (SMR)	7,339	7,301	7,257	7,217	7,176	7,126	7,079	7,030	6,979	6,936	6,891	6,836	6,791	6,744	6,691	6,637	6,595	6,544	6,497	6,450	6,406

Table 8-3. Fixed O&M ($/kW-yr) (2021 $)

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	13	13	12	11	11	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9
BTM Solar	12	12	11	10	10	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8	7
Wind	43	43	42	42	42	41	41	41	40	40	40	39	39	39	38	38	38	38	37	37	37
Geothermal	187	186	185	185	184	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183
Biomass	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Standalone Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Paired Batteries	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Gas Peaker	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Nuclear (SMR)	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126

[52] This wind resource corresponds to land-based wind class 3 in the NREL ATB.
[53] This wind resource corresponds to land-based wind class 7 in the NREL ATB.

Table 8-4 provides the $/kW-yr levelized cost for each resource over time. The levelized cost reflects the total cost of a resource – including capital costs, fixed O&M, financing costs, taxes, tax credits,[54] etc. – on a levelized basis over the financial lifetime of project. E3 developed a pro forma financial model to determine the total levelized costs for each resource. The $/kW-yr levelized cost is a direct input into the resource portfolio optimization.

Table 8-4. Real Levelized Cost ($/kW-yr) (2021 $)[55]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Utility-Scale Solar	48	58	57	55	53	51	51	50	50	50	49	49	48	48	48	47	47	47	46	46	45
BTM Solar	65	87	84	81	77	73	72	71	70	69	69	68	67	66	65	64	63	63	62	61	60
Wind (Artesia/ABQ)	98	133	132	131	130	128	127	126	125	124	123	122	121	120	118	117	116	115	114	113	112
Wind (Lordsburg)	129	150	150	148	146	144	143	142	141	140	139	138	137	136	135	134	133	131	130	129	128
Geothermal	663	672	680	680	680	679	677	675	672	670	667	665	663	660	658	656	653	651	649	646	644
Biomass	440	448	455	458	460	462	460	459	457	456	454	452	451	449	447	445	444	442	441	439	438
Standalone Batteries	90	86	82	77	73	69	68	67	66	66	65	64	63	63	62	61	61	60	59	59	58
Paired Batteries	63	71	68	64	60	56	55	55	54	54	53	52	52	51	51	50	50	49	49	48	47
Gas Peaker[56]	117	116	116	116	116	115	115	114	114	114	113	113	113	113	112	112	112	112	112	111	111
Nuclear (SMR)	652	654	657	660	662	664	661	657	653	650	647	642	639	636	632	628	624	621	617	613	610
Smart Thermostats	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29

Table 8-5 provides the capacity factor for each resource that has a production profile that varies by season and time of day. Section 0 provides more information about the development of profiles for these resources.

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[54] E3 assumes that solar projects coming online in 2025 would be eligible for a 26% investment tax credit (ITC) and that projects coming online in later years would be eligible for a 10% ITC. E3 assumes that wind projects coming online in 2025 would be eligible for a 60% production tax credit (PTC) and that projects coming online in later years would not be eligible for the PTC.

[55] The levelized cost includes interconnection costs.

[56] The levelized cost for Gas Peaker includes gas pipeline reservation costs.

Table 8-5. Capacity Factor (%)

Resource	Capacity Factor
Solar[57]	32%
BTM Solar	24%
Wind (Artesia)	44%
Wind (ABQ)	50%
Wind (Lordsburg)	37%
Geothermal	80%

Table 8-6 provides the $/MWh levelized cost of each resource that has a production profile that varies by season and time of day. This data is not a direct model input but is provided to allow for a more intuitive comparison of costs between different resources. The table does not include all resources because some resources' output levels are not based on resource production profiles but instead on system dispatch dynamics. The $/kW-yr levelized cost is the direct resource portfolio optimization input for all resources.

Table 8-6. Real Levelized Cost of Energy ($/MWh) (2021 $)[58]

Resources	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Solar	17	21	20	20	19	18	18	18	18	18	18	17	17	17	17	17	17	17	17	16	16
BTM Solar	31	42	41	39	37	35	35	34	34	33	33	33	32	32	31	31	31	30	30	29	29
Wind (Artesia)	25	34	34	34	34	33	33	33	32	32	32	32	31	31	31	30	30	30	30	29	29
Wind (ABQ)	22	30	30	30	30	29	29	29	29	28	28	28	28	27	27	27	27	26	26	26	26
Wind (Lordsburg)	40	46	46	46	45	44	44	44	44	43	43	43	42	42	42	41	41	41	40	40	40
Geothermal	95	96	97	97	97	97	97	96	96	96	95	95	95	94	94	94	93	93	93	92	92

Table 8-7 provides the characteristics for thermal candidate resources. The assumptions are based on data from the NREL ATB.

[57] The capacity factor for solar PV differs slightly by location. This value is used for illustrative purposes for calculating the levelized cost of energy.
[58] The levelized cost of energy is not a direct model input. Also, the metric does not indicate the value of individual resources, which is determined dynamically through the capacity expansion model. Nevertheless, the metric can be useful for understanding the relative cost of resources.

Table 8-7. Thermal Resource Characteristics

Resource	Heat Rate (MMBtu/MWh)	Variable O&M (2021$/MWh)
Gas Peaker	10.1	$1.17
Biomass	13.5	$5.00
Nuclear (SMR)	10.0	$2.00

Table 8-8 provides lifetime extension assumptions for a subset of existing thermal units. El Paso Electric engaged Burns & McDonnell to determine the capital cost and fixed O&M required to extend the lifetime of these units by five years. E3 utilized these costs to determine whether it would be economic to extend the lifetime of these units.

Table 8-8. Lifetime Extension Costs ($/kW-yr) (2021 $)

Resource	Extension Period	Capital + Fixed O&M
Rio Grande 7	5 years	$114
Newman 1	5 years	$79
Newman 2	5 years	$80
Newman 3	5 years	$58
Newman 4	5 years	$47

Table 8-9 provides the cost assumption for converting a natural gas-fired generating unit to burn hydrogen fuel. This retrofit option is considered in select cases with aggressive decarbonization targets.

Table 8-9. Hydrogen Retrofit Cost ($/kW-yr) (2021 $)

Resource	Additional Cost
Gas Plants	$12

9 Appendix B: Price Assumptions

This appendix provides the assumptions for prices utilized in the resource portfolio optimization.

9.1 Fuel Prices

Table 9-1 includes the forecasts for different types of fuel. El Paso Electric provided natural gas price forecasts for GasInter,[59] NewInter,[60] and GasIntra[61] through 2029. E3 trended the gas prices upward through 2045 in line with the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO). E3 utilized the uranium price forecast from the EIA 2020 AEO. E3 utilized the biomass price forecast from the 2020 NREL ATB.

E3 forecast the cost of green hydrogen – hydrogen fuel produced through electrolysis using renewable energy – through 2045. E3 assumed cost declines for electrolyzers and renewable energy over time and utilized these assumptions to determine the cost of producing green hydrogen. The assumptions and methodology are described in more detail in a report that E3 prepared for Advanced Clean Energy Storage (ACES),[62] which is a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC.

[59] GasInter is interstate gas with service provided by EPNG. This gas is utilized at the Rio Grande power plant.
[60] NewInter is interstate gas with service provided by EPNG. The gas is utilized at Montana and Newman power plants as well as for candidate gas resources
[61] GasIntra is intrastate gas with service provided by Oneok. The gas is utilized at the Newman and Copper power plants.
[62] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Table 9-1. Fuel Prices ($/MMBtu) (2021 $)

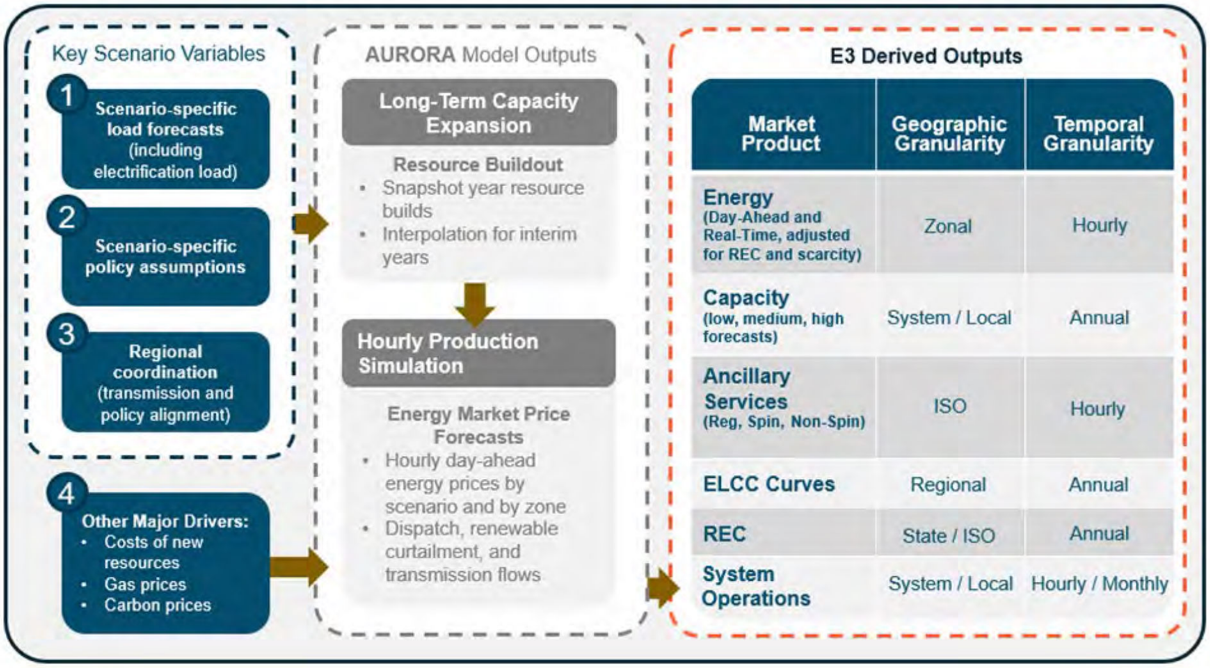
Year	GasInter	NewInter	GasIntra	Uranium	Biomass	Hydrogen
2021	2.84	2.76	2.89	0.71	3.18	27.61
2022	2.48	2.41	2.53	0.71	3.18	26.76
2023	2.52	2.45	2.56	0.71	3.18	25.92
2024	2.58	2.51	2.63	0.71	3.18	25.07
2025	2.67	2.59	2.71	0.71	3.18	24.23
2026	2.74	2.65	2.77	0.71	3.18	23.95
2027	2.85	2.76	2.88	0.72	3.18	23.68
2028	2.94	2.85	2.98	0.72	3.18	23.40
2029	3.00	2.90	3.03	0.72	3.18	23.13
2030	3.06	2.96	3.09	0.72	3.18	22.85
2031	3.13	3.02	3.16	0.72	3.18	22.40
2032	3.19	3.08	3.21	0.72	3.18	21.94
2033	3.24	3.13	3.27	0.73	3.18	21.48
2034	3.30	3.18	3.32	0.73	3.18	21.02
2035	3.35	3.23	3.36	0.73	3.18	20.56
2036	3.39	3.27	3.41	0.73	3.18	20.21
2037	3.44	3.31	3.45	0.73	3.18	19.85
2038	3.48	3.35	3.49	0.73	3.18	19.50
2039	3.51	3.38	3.52	0.74	3.18	19.14
2040	3.55	3.42	3.55	0.74	3.18	18.79
2041	3.55	3.42	3.56	0.74	3.18	18.53
2042	3.58	3.45	3.59	0.74	3.18	18.26
2043	3.61	3.47	3.61	0.74	3.18	18.00
2044	3.63	3.49	3.63	0.75	3.18	17.74
2045	3.66	3.52	3.66	0.75	3.18	17.48

9.2 Wholesale Electricity Prices

In this study, E3 utilized its market price forecasts for the Palo Verde market hub to assess the potential for economic short-term energy purchases. This section describes the methodology the E3 employs to develop its market price forecast. This section also provides a summary of the market prices.

E3 develops unique energy market price forecasts using a hybrid approach which combines capacity expansion, production cost simulation, and post-process calculations to develop robust and expansive views of the future electricity system under high renewable penetration levels. E3 has designed its market price forecasts to be scenario-based, policy-centered, and fundamentals-driven in order to identify, simulate, and evaluate step-changes in market evolution arising from a combination of policy, economic, and technological factors.

Figure 9-1. E3 Modeling Approach for Energy Market Price Forecasting



The price forecasting methodology comprises five principal steps:

+ **Scenario Definition** – design integrated scenarios for the long-run, future trajectory of the market

+ **Model Inputs** – create all parameters required for capacity expansion and production cost simulation, using public and proprietary data (tailored to each scenario)

+ **Long-Term Capacity Expansion** – identify resource additions and retirements based on economics, policy requirements (RPS, GHG standards), and reliability needs (Planning Reserve Margin and effective load carrying capability of each resource). E3 uses Aurora modeling software from Energy Exemplar for capacity expansion and benchmarks the results to E3's proprietary, in-house capacity expansion model RESOLVE, which has been the core modeling tool for much of E3's Integrated Resource Planning work, including E3's ongoing support of the California Public Utility Commission (CPUC) IRP for California

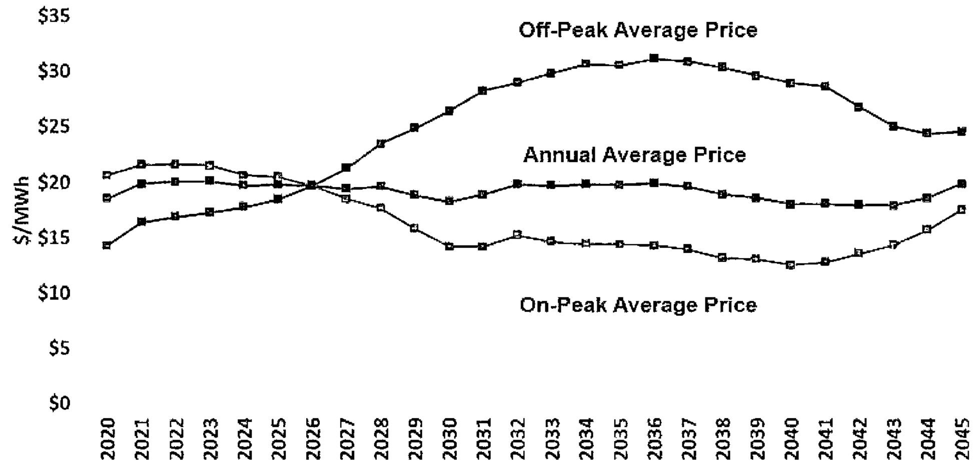
+ **Production Cost Simulation** – simulate day-ahead, zonal energy prices using the Aurora software for each forecast year (2020-2050) and each scenario. Production cost simulation is at the core of E3's 'fundamentals-driven' approach to energy price forecasting because it captures how changes in resources and loads can affect the frequency, magnitude, and shape of energy prices in the long run. The strength of production cost simulation models is the ability to identify and explain step-changes and trends in the market which differ dramatically from past or current relationships (and hence are not well-explained or forecasted by statistical approaches alone).

- A commonly known drawback of production cost simulations, however, is that they tend to 'over-optimize' future prices and often fall short in accounting for inefficiencies and volatility driven by real-world market conditions such as scarcity pricing, sub-zonal transmission constraints, and weather variability beyond Typical Meteorological Year (TMY) conditions. Because of these constraints, production cost simulations also do not capture trends in ancillary services pricing particularly well. To build upon the strength of production cost simulations (and industry best-practices), E3 has created a toolkit of post-processing calculations to add back real-world volatility and system constraints into the DA energy price forecasts and to use these prices to derive AS and REC forecasts that are aligned with changing fundamentals but calibrated to historical observations of system dynamics.

+ **Post Processing** – E3 uses the raw outputs of the Aurora production cost simulation to create hourly DA energy prices and to derive prices for ancillary services (regulation up/down, spinning reserves, and non-spinning reserves), real-time 15min energy prices, and forecasts of renewable energy credit (REC) prices. Our post-processing also adjusts the top hours of the DA energy prices to simulate the frequency and magnitude of observed occurrences of scarcity pricing and peak unit dispatch during high-load hours as well as the occurrence of zero and negative pricing during low load hours due to congestion within zones. E3 also uses the day-ahead energy prices to forecast capacity or resource adequacy prices by calculating annual fixed costs of existing and new capacity resources net of energy market participation. Our capacity price forecasts account for going-forward costs of existing resources, the effective load carrying capability (ELCC) of new resources, and forecasted planning reserve margins for the system. We also tailor our price outlook to account for specific market rules and procurement methods (i.e., state-administered resource adequacy programs vs. organized capacity markets).

Figure 9-2 summarizes E3's market price forecast for the Palo Verde market hub for on-peak hours (7am-11pm) and off-peak hours (11pm-7am), as well as the overall average price. The market price forecast shows daytime energy prices falling in the next ten years, largely due to the addition of significant quantities of solar PV resources in the Southwest. Concurrently, the market price forecast shows nighttime energy prices increasing, largely due to rising fuel prices and resource retirements.

Figure 9-2. E3 Market Price Forecast for the Palo Verde Market Hub ($/MWh) (2021 $)



EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE P-13 SUMMARY OF CHANGES IN ALLOCATION FACTORS
SPONSOR. ADRIAN HERNANDEZ
PREPARER. ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

LINE NO.	FERC ACCT.	DESCRIPTION	44941 FILED ALLOCATOR	DOCKET 44941 DESCRIPTION FOR ALLOCATION	46831 ALLOCATOR	DOCKET 46831 DESCRIPTION FOR ALLOCATION
1	368000	Line Transformers	D5DIST	NCP Demand Transformers	D5DIST-PRIM	MCD Demand Transformers - Primary
					D5DIST-SEC	NCP Demand Transformers - Secondary
2	556000	Sys. Control & Load Dispatch	D1PROD	AED 4CP Demand - Production	DPROD12	12CP Demand - Production
3	561000	Load Dispatching	D2TRAN	4CP Demand - Transmission	DTRAN12	12CP Demand - Transmission
4	903000	Customer Records & Collect	CUST903	Account 903 Customer Records & Collect.	CUSTSVC	Customer Records & Collect
					MAJ_ACCT_REPS	Major Customer Services
5	440000 - 445000	Revenues	NA	NA	rc_01_03_BASE	Base Revenue Split between Residential and DG Rate Classes
					rc_01_03_FUEL	Fuel Revenue Split between Residential and DG Rate Classes
					rc_01	Assign to Residential Rate Class
					rc_02	Assign to Small General Service Rate Class
					rc_03	Assign to Residential DG Rate Class
					rc_07	Assign to Outdoor Recreational Lighting Rate Class
					rc_08	Assign to Governmental Street Lighting Rate Class
					rc_09	Assign to Governmental Traffic Signal Rate Class
					11TOU	Assign to Time of Use Municipal Pumping Rate Class
					rc_11	Assign to Municipal Pumping Rate Class
					rc_15	Assign to Electrolytic Refining Rate Class
					rc_22	Assign to Irrigation Rate Class
					rc_24	Assign to General Service Rate Class
					rc_25	Assign to Large Power Rate Class
					rc_26	Assign to Petroleum Refinery Rate Class
					rc_28	Assign to Area Lighting Rate Class
					rc_30	Assign to Electric Furnace Rate Class
					rc_31	Assign to Military Reservation Rate Class
					rc_34	Assign to Cotton Gin Rate Class
					rc_41	Assign to City and County Rate Class
					WH	Assign to Water Heating Rate Class

NOTE: Except as noted above, EPE is proposing the same allocation factors as EPE proposed in Docket No 44941, which was a settled case.

SCHEDULE P-13
PAGE 1 OF 1

EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE Q-7: PROOF OF REVENUE STATEMENT
SPONSOR. MANUEL CARRASCO
PREPARER: RENE F. GONZALEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
1	Rate 1 - Residential Service Rate					
2	Customer Charge - Non LIR	3,397,380	$	6 90	$	23,441,922
3	Customer Charge - Low Income Rider	116,523	$	(6.90)	$	(804,011)
4	Energy Charge ($/kWh) Summer Block 1 (0 - 600 kWh)	784,809,397	$	0.09455	$	74,203,728
5	Energy Charge ($/kWh) Summer Block 2 (All Other kWh)	507,626,093	$	0 09956	$	50,539,254
6	Energy Charge ($/kWh) Winter (All kWh)	830,456,920	$	0 08455	$	70,215,133
7	Four Corners Surcharge	2,122,892,410	$	0.00125	$	2,653,616
8	Total kWh Sales and Revenues	2,122,892,410			$	220,249,642
9						
10	Rate 2 - Small General Service Rate					
11	Customer Charge	309,432	$	9.95	$	3,078,848
12	Customer Charge - Nonmetered Customers	12,504	$	9.95	$	124,415
13	Energy Charge ($/kWh) - Summer (All kWh)	158,112,429	$	0 11407	$	18,035,885
14	Energy Charge ($/kWh) - Winter (All kWh)	119,205,513	$	0 10407	$	12,405,718
15	Four Corners Surcharge	277,317,942	$	0 00053	$	146,979
16	Total kWh Sales and Revenues	277,317,942			$	33,791,844
17						
18	Rate 7 - Outdoor Recreational Lighting Service Rate					
19	Customer Charge - Secondary	2,196	$	23 75	$	52,155
20	Customer Charge - Primary	132	$	23 75	$	3,135
21	Energy Charge ($/kWh) - Secondary Voltage (All kWh)	5,216,037	$	0 08783	$	458,125
22	Energy Charge ($/kWh) - Primary Voltage (All kWh)	102,509	$	0 06271	$	6,428
23	Four Corners Surcharge - Secondary	5,216,037	$	0 00150	$	7,824
24	Four Corners Surcharge - Primary	102,509	$	0.00150	$	154
25	Total kWh Sales and Revenues	5,318,546			$	527,821
26						
27	Rate 8 - Governmental Street Lighting Service Rate					
28	7,000 Lumens Single 175W MV Overhead CO 35ft Wood Pole	5,220	$	17 30	$	90,306
29	11,000 Lumens Single 250W MV Overhead CO 35ft Wood Pole	3,480	$	19 74	$	68,695
30	20,000 Lumens Single 400W MV Overhead CO 35ft Wood Pole	360	$	25 28	$	9,101
31	20,000 Lumens Double 400W MV Overhead CO 35ft Wood Pole	-	$	40.16	$	-
32	119,500 Lumens 1,000W HPS Overhead CO 30ft Steel Pole	24	$	59 22	$	1,421
33	119,500 Lumens 1,000W HPS Underground CO 30ft Steel Pole	96	$	96 65	$	9,278
34	50,000 Lumens 450W HPS Overhead CO 30ft Steel Pole	996	$	51 73	$	51,523
35	20,000 Lumens Single 400W MV Overhead CO 30ft Steel Pole	852	$	36 16	$	30,808
36	20,000 Lumens Double 400W MV Overhead CO 30ft Steel Pole	108	$	50 77	$	5,483
37	11,000 Lumens Wall Mount 250W MV Non-CO Frwy Lghtng	264	$	10 57	$	2,790
38	20,000 Lumens 40ft Mount Hght 400W MV Non-CO Frwy Lghtng	168	$	14.54	$	2,443
39	60,000 Lumens 50ft Mount Hght 1,000W MV Non-CO Frwy Lghtng	-	$	38.12	$	-
40	7,000 Lumens 35ft 175W MV UG or OH Non-CO Wood Pole Res Srvc	108	$	8.02	$	866
41	16,000 Lumens Wall Mount 150W HPS Non-CO System Frwy Lghtng	6,888	$	8 42	$	57,997
42	23,200 Lumens Wall Mount 250W HPS Non-CO System Frwy Lghtng	1,224	$	11.34	$	13,880
43	23,200 Lumens 40ft MntHgt 250W HPS Non-CO System Frwy Lghtng	-	$	11 34	$	-
44	50,000 Lumens 50ft MntHgt 400W HPS Non-CO System Frwy Lghtng	25,932	$	15 59	$	404,280
45	50,000 Lumens 150ft Tower-Climbing 400W HPS Non-CO Sys Frwy	-	$	16 45	$	-
46	50,000 Lumens 150ft Tower-Lowering 400W HPS Non-CO Sys Frwy	1,344	$	16 45	$	22,109
47	Obstruction Lights Incandescent 40ft 116W HPS NonCO Sys Frwy	72	$	4 83	$	348
48	150 FT Tower 116W HPS Non-CO Sys Frwy	36	$	5.78	$	208
49	16,000 Lumens Wall Mount 150W HPS Non-CO Sys Arterial	-	$	8.56	$	-
50	23,200 Lumens Wall Mount 250W HPS Non-CO Sys Arterial	-	$	12 32	$	-
51	23,200 Lumens 40ft Mnt Hgt 250W HPS Non-CO Sys Arterial	4,236	$	12 32	$	52,188
52	50,000 Lumens 50ft Mnt Hgt 400W HPS Non-CO Sys Arterial	7,620	$	17.73	$	135,103
53	8,500 Lumens 30ft MntHgt 100W HPS UG/OH Non-CO Pole Res	42,876	$	5.95	$	255,112
54	14,400 Lumens 30ft MntHgt 150W HPS UG/OH Non-CO Pole Res	-	$	7 47	$	-

EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE Q-7: PROOF OF REVENUE STATEMENT
SPONSOR: MANUEL CARRASCO
PREPARER: RENE F. GONZALEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
55	23,200 Lumens 30ft MntHgt 250W HPS UG/OH Non-CO Pole Res	31,176	$	11 46	$	357,277
56	8,500 Lumens 35ft 100W HPS OH NonCO Stand Fxtr CO Wood Pole	29,856	$	8.03	$	239,744
57	14,400 Lumens 35ft 150W HPS OH NonCO Stand Fxtr CO Wood Pole	30,348	$	9.71	$	294,679
58	23,200 Lumens 35ft 250W HPS OH NonCO Stand Fxtr CO Wood Pole	11,448	$	12.33	$	141,154
59	23,200 Lumens Dbl 250W HPS OH NonCO Stand Fxtr CO Wood Pole	132	$	21.91	$	2,892
60	50,000 Lumens 50ft 450W HPS OH NonCO Stand Fxtr CO Wood Pole	228	$	16 92	$	3,858
61	8,500 Lumens 35ft Mnt Hgt 100W HPS Overhead CO Wood Pole	12,084	$	16.42	$	198,419
62	14,400 Lumens 35ft Mnt Hgt 150W HPS Overhead CO Wood Pole	7,848	$	17.82	$	139,851
63	23,200 Lumens 35ft Mnt Hgt 250W HPS Overhead CO Wood Pole	4,800	$	20 86	$	100,128
64	50,000 Lumens 50ft Mnt Hgt 400W HPS Overhead CO Wood Pole	1,656	$	29.99	$	49,663
65	5,300 Lumens 70W Ornament HPS Non-CO Operated Maintained	-	$	2 01	$	-
66	14,400 Lumens 150W Ornament HPS Non-CO Operated Maintained	-	$	3 66	$	-
67	14,400 Lumens 175W Ornament HPS Non-CO Operated Maintained	5,868	$	3.98	$	23,355
68	16,000 Lumens 250W Ornament HPS Non-CO Operated Maintained	252	$	4.74	$	1,194
69	State of Texas Lighting 100W HPS Non-CO Owned Roadway Illum	2,952	$	2 46	$	7,262
70	State of Texas Lighting 150W HPS Non-CO Owned Roadway Illum	1,368	$	3 82	$	5,226
71	State of Texas Lighting 250W HPS Non-CO Owned Roadway Illum	16,452	$	6 11	$	100,522
72	State of Texas Lighting 400W HPS Non-CO Owned Roadway Illum	27,732	$	14.57	$	404,055
73	31W-40W LED - Street Light - Non Company Owned and Maint Sys	84,948	$	0.69	$	58,614
74	41W-50W LED - Street Light - Non Company Owned and Maint Sys	312	$	0 89	$	278
75	65W LED replacing 7K Lumens Single Overhead CO 35ft Wd Pole	16,224	$	13.34	$	216,428
76	65W LED replacing 8 5K Lumen 35ft Mnt Hgt Ovrhd CO Wd Pole	1,368	$	13.03	$	17,825
77	61W-70W LED - Street Light - Non Company Owned and Maint Sys	27,444	$	1 29	$	35,403
78	71W-80W LED - Street Light - Non Company Owned and Maint Sys	744	$	1 49	$	1,109
79	91W-100W LED - Street Light - Non Company Owned and Maint Sy	13,440	$	1 90	$	25,536
80	100W LED replacing 11K Lumen Single Overhead CO 35ft Wd Pole	756	$	16.68	$	12,610
81	100W LED replacing 20K Lumen Single Overhead CO 35ft Wd Pole	540	$	19.77	$	10,676
82	101W-110W LED - Street Light - Non Company Owned and Maint S	29,484	$	2.01	$	59,263
83	116W LED replacing 23 2K Lumen 35ft Mnt Hgt Ovrhd CO Wd Pole	456	$	17.80	$	8,117
84	111W-130W LED - Street Light - Non Company Owned and Maint S	12,348	$	2 29	$	28,277
85	131W-150W LED - Street Light - Non Company Owned and Maint S	1,560	$	2.67	$	4,165
86	151W-170W LED - Street Light - Non Company Owned and Maint S	13,116	$	3.19	$	41,840
87	32W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	60	$	2 05	$	123
88	32W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	60	$	-	$	-
89	65W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	3,672	$	2 05	$	7,528
90	65W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	3,672	$	-	$	-
91	95W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	672	$	2 05	$	1,378
92	95W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	672	$	-	$	-
93	100W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	948	$	2.05	$	1,943
94	100W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	960	$	-	$	-
95	116W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	1,440	$	2.05	$	2,952
96	116W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	1,968	$	-	$	-
97	159W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	444	$	2 05	$	910
98	159W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	456	$	-	$	-
99	252W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	2,592	$	-	$	-
100	Energy ($/kWH)	482,484	$	0.05	$	22,749
101	Four Corners Surcharge (LED Only)	5,585,225	$	0 00158	$	8,825
102	Four Corners Surcharge	27,645,418	$	0 00158	$	43,680
103	Total kWh Sales and Revenues	33,230,643			$	3,893,446
104						
105	Rate 9 - Governmental Traffic Signal Service Rate					
106	4 Unit School Flasher 14W 351ABHrs LED Traffic Signal	-	$	0 79	$	-
107	2 Unit School Flashers 14W 351ABHrs LED Traffic Signal	-	$	0.36	$	-
108	4 Unit School Flasher 14W 790ABHrs LED Traffic Signal	-	$	0.79	$	-
109	2 Unit School Flasher 14W 790ABHrs LED Traffic Signal	11,592	$	0 36	$	4,173

EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE Q-7: PROOF OF REVENUE STATEMENT
SPONSOR. MANUEL CARRASCO
PREPARER: RENE F GONZALEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
110	2 U School Flasher 103W 351ABhrs Incandescent Traffic Signal	-	$	2 71	$	-
111	2 U School Flasher 133W 790ABhrs Incandescent Traffic Signal	24	$	3.52	$	84
112	2 Unit Walk Light 9W 18HrsN 6HrsF LED Traffic Signal	-	$	0.30	$	-
113	2 Unit Walk Light 9W 24Hrs LED Traffic Signal	58,488	$	0.30	$	17,546
114	2 Unit Flashing 14W 24Hr LED Traffic Signal	96	$	0.45	$	43
115	3 Lamp Head 14W 18HrsN 6HrsF LED Trafic Signals	-	$	0 44	$	-
116	4 Lamp Head 14W 18HrsN 6HrsF LED Traffic Signals	-	$	0 79	$	-
117	5 Lamp Head 14W 24Hrs LED Traffic Signal	9,216	$	0.79	$	7,281
118	1 Unit Flashing 14W 24Hrs LED Traffic Signal	3,168	$	0.23	$	729
119	3 Lamp Head 14W 24Hrs LED Traffic Signal	75,612	$	0 45	$	34,025
120	4 Lamp Head 14W 24Hrs LED Traffic Signal	2,484	$	0 79	$	1,962
121	30 Watt Controller 30W 24Hrs Incandescent Traffic Signal	576	$	0.79	$	455
122	3 Lamp Head 61W 24Hrs Incandescent Traffic Signal	-	$	1 61	$	-
123	4 Lamp Head 61W 24Hrs incandescent Traffic Signal	-	$	1.61	$	-
124	2 Unit Walk Light 61W 24Hrs Incandescent Traffic Signal	-	$	1.61	$	-
125	100 Watt Controller 100W 24Hrs LED Traffic Signal	8,064	$	3 37	$	27,176
126	2 Unit Walk Light 103W 24Hrs Incandescent Traffic Signal	-	$	2.71	$	-
127	4 Lamp Head 103W 18HrsN 6HrsF Incandescent Traffic Signal	-	$	2.71	$	-
128	1 Unit Flashing 103W 24Hrs Incandescent Traffic Signal	-	$	2 71	$	-
129	2 Unit Walk Lght 103W 18HrsN 6HrsF Incandescent Traffic Sign	-	$	2 71	$	
130	3 Lamp Head 103W 18HrsN 6HrsF Incandescent Traffic Signal	-	$	2.71	$	
131	3 Lamp Head 103W 24Hrs Incandescent Traffic Signal	-	$	2.71	$	
132	3 Lamp Head 133W 24Hrs Incandescent Traffic Signal	-	$	3.52	$	
133	4 Lamp head 133W 24Hrs Incandescent Traffic Signal	-	$	3.52	$	
134	5 Lamp Head 133W 24Hrs Incandescent Traffic Signal	-	$	3 52	$	
135	1 Unit Flashing 133W 24Hr Incandescent Traffic Signal	-	$	3.52	$	-
136	3 Lamp Head 133W 18HrsN 6HrsF Incandenscent Traffic Signal	-	$	3 52	$	-
137	4 Lamp Head 133W 18HrsN 6HrsF Incandescent Traffic Signal	-	$	3.52	$	-
138	Four Corners Surcharge	2,629,032	$	0.00081	$	2,130
139	Total kWh Sales and Revenues	2,629,032			$	95,604
140						
141	Rate 11 - Municipal Pumping Service Rate					
142	Customer Charge (Secondary)	2,136	$	24.50	$	52,332
143	Customer Charge (Primary)	-	$	24.50	$	-
144	Energy Charge ($/kWh) - Summer (All kWh) - Secondary	6,111,864	$	0.06611	$	404,055
145	Energy Charge ($/kWh) - Summer (All kWh) - Primary	-	$	0.06225	$	-
146	Energy Charge ($/kWh) - Winter (All kWh) - Secondary	9.764,089	$	0.05611	$	547,863
147	Energy Charge ($/kWh) - Winter (All kWh) - Primary	-	$	0.05225	$	-
148	Four Corners Surcharge - Secondary	15.875,952	$	0.00022	$	3,493
149	Four Corners Surcharge - Primary	-	$	0.00022	$	-
150	Total kWh Sales and Revenues	15,875,952			$	1,007,743
151						
152	Rate 11 - TOU Municipal Pumping Service Rate					
153	Customer Charge - Secondary	2,772	$	55.45	$	153,707
154	Customer Charge - Primary	131	$	55 45	$	7,264
155	Energy Charge On-Peak - ($/kWh) - Secondary	3,344,041	$	0 21049	$	703,887
156	Energy Charge Shoulder-Peak - ($/kWh) - Secondary	5,630,819	$	0 10845	$	610.662
157	Energy Charge Off-Peak - ($/kWh) - Secondary	88,761,282	$	0.04507	$	4,000,471
158	Energy Charge On-Peak - ($/kWh) - Primary	1,788,457	$	0 20820	$	372,357
159	Energy Charge Shoulder-Peak - ($/kWh) - Primary	2,715,828	$	0.10616	$	288,312
160	Energy Charge Off-Peak - ($/kWh) - Primary	41,359,347	$	0 04278	$	1,769,353
161	Four Corners Surcharge - Secondary	97,736,142	$	0.00024	$	23,457
162	Four Corners Surcharge - Primary	45,863,632	$	0.00024	$	11,007
163	Total kWh Sales and Revenues	143,599,774			$	7,940,478
164						

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
165	Rate 15 - Electrolytic Refining Service Rate					
166	Customer Charge	12	$	110 50	$	1,326
167	Energy Charge On-Peak ($/kWh) - Summer	2,528,602	$	0.14630	$	369,934
168	Energy Charge Off-Peak ($/kWh) - Summer	14,417,011	$	0.00700	$	100,919
169	Energy Charge Off-Peak ($/kWh) - Winter (All kWh)	38,835,785	$	0 00700	$	271,850
170	Demand Charge ($/kW) - Summer	40,000	$	15.77	$	630,800
171	Demand Charge ($/kW) - Winter	80,000	$	11 58	$	926,400
172	Interconnection Charge	79,957		5 3178%	$	4,252
173	Four Corners Surcharge	55,781,398	$	0.00001	$	558
174	Total kWh Sales and Revenues	55,781,398			$	2,306,040
175						
176	Rider - Water Heating Rider (Rider to Rate Nos 01, 02 and 24)					
177	Customer Charge	55,680	$	6.50000	$	361,920
178	Energy Charge ($/kWh) - Summer (All kWh)	3,551,937	$	0 03547	$	125,987
179	Energy Charge ($/kWh) - Winter (All kWh)	5,111,639	$	0 02548	$	130,245
180	Four Corners Surcharge	8,663,576	$	0.00150	$	12,995
181	Total kWh Sales and Revenues	8,663,576			$	631,147
182						
183	Rate 22 - Irrigation Service Rate					
184	Customer Charge	1,668	$	22.75	$	37,947
185	Energy Charge ($/kWh) - Summer (All kWh)	2,236,282	$	0 10426	$	233,155
186	Energy Charge ($/kWh) - Winter (All kWh)	2,809,258	$	0.08075	$	226,848
187	Four Corners Surcharge	5,045,540	$	0.00114	$	5,752
188	Total kWh Sales and Revenues	5,045,540			$	503,701
189						
190	Rate 24 - General Service Rate					
191	Secondary Voltage					
192	Customer Charge	79,596	$	27 50	$	2,188,890
193	Energy Charge ($/kWh) - Summer (0 - 200 kW hours)	463,299,988	$	0 06927	$	32,092,790
194	Energy Charge ($/kWh) - Summer (next 150 kW hours)	243,904,114	$	0 05038	$	12,287,889
195	Energy Charge ($/kWh) - Summer (all addt'l kW hours)	147,668,013	$	0.03664	$	5,410,556
196	Demand Charge ($/kW) - Summer	2,425,947	$	12 21	$	29,620,813
197	Winter Energy Charge (0 - 200 kW hours) ($/kWh)	361,374,459	$	0 03408	$	12,315,642
198	Winter Energy Charge (next 150 kW hours) ($/kWh)	179,100,973	$	0 02479	$	4,439,913
199	Winter Energy Charge (all addt'l kW hours) ($/kWh)	100,821,059	$	0.01803	$	1,817,804
200	Demand Charge ($/kW) - Winter	1,964,497	$	8.50	$	16,698,225
201	Four Corners Surcharge	1,496,168,629	$	0.00029	$	433,889
202	Primary Voltage					
203	Customer Charge	480	$	27 50	$	13,200
204	Energy Charge ($/kWh) - Summer (0 - 200 kW hours)	9,975,363	$	0 05513	$	549,942
205	Energy Charge ($/kWh) - Summer (next 150 kW hours)	6,714,655	$	0.04008	$	269,123
206	Energy Charge ($/kWh) - Summer (all addt'l kW hours)	4,245,165	$	0 02914	$	123,704
207	Demand Charge ($/kW) - Summer	51,223	$	10.95	$	560,892
208	Power Factor Adjustment ($/kW)	1,609	$	10 95	$	17,619
209	Energy Charge ($/kWh) - Winter (0 - 200 kW hours)	8,439,486	$	0 02712	$	228,879
210	Energy Charge ($/kWh) - Winter (next 150 kW hours)	5,139,914	$	0 01973	$	101,411
211	Energy Charge ($/kWh) - Winter (all addt'l kW hours)	2,191,520	$	0.01435	$	31,448
212	Demand Charge ($/kW) - Winter	42,425	$	7.24	$	307,157
213	Power Factor Adjustment ($/kW)	898	$	7.24	$	6,502
214	Four Corners Surcharge	36,706,103	$	0.00029	$	10,645
215	Total kWh Sales and Revenues	1,532,874,710			$	119,526,931
216						
217	Rate 25 - Large Power Service Rate					
218	Secondary Voltage					
219	Customer Charge	1,088	$	100 00	$	108,800

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FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
220	Customer Charge - Experimental Off-Peak Rider	-	$	100.00	$	-
221	Energy Charge ($/kWh) On-Peak	37,550,929	$	0.12100	$	4,543,662
222	Energy Charge ($/kWh) Off-Peak	438,854,984	$	0 00812	$	3,563,502
223	Energy Charge ($/kWh) Time-of-Use On-Peak - Experimental Off-Peak Rider	-	$	0 12100	$	-
224	Energy Charge ($/kWh) Time-of-Use Maximum - Experimental Off-Peak Rider	-	$	0.00812	$	-
225	Demand Charge ($/kW) Summer	358,738	$	22 04	$	7,906,586
226	Demand Charge ($/kW) Winter	662,676	$	17 85	$	11,828,767
227	Demand Charge ($/kW) On-Peak Maximum - Experimental Off-Peak Rider	-	$	25 81	$	-
228	Demand Charge ($/kW) Off-Peak Maximum - Experimental Off-Peak Rider	-	$	12 75	$	-
229	Power Factor Adjustment ($/kW) Summer	9,901	$	22.04	$	218,218
230	Power Factor Adjustment ($/kW) Winter	15,720	$	17.85	$	280,602
231	Power Factor Adjustment ($/kW) - Experimental Off-Peak Rider	-	$	12 75	$	-
232	Four Corners Surcharge	476,405,921	$	0.00008	$	38,112
233	Primary Voltage					
234	Customer Charge	216	$	100 00	$	21,600
235	Customer Charge - Experimental Off-Peak Rider	12	$	100.00	$	1,200
236	Energy Charge ($/kWh) On-Peak	11,884,224	$	0 11818	$	1,404,478
237	Energy Charge ($/kWh) Off-Peak	148,406,541	$	0 00793	$	1,176,864
238	Energy Charge ($/kWh) Time-of-Use On-Peak - Experimental Off-Peak Rider	-	$	0 11818	$	-
239	Energy Charge ($/kWh) Time-of-Use Maximum - Experimental Off-Peak Rider	1,358,604	$	0.00793	$	10,774
240	Demand Charge ($/kW) Summer	123,335	$	21.30	$	2,627,036
241	Demand Charge ($/kW) Winter	231,059	$	17 11	$	3,953,419
242	Demand Charge ($/kW) On-Peak Maximum - Experimental Off-Peak Rider	-	$	25.07	$	-
243	Demand Charge ($/kW) Off-Peak Maximum - Experimental Off-Peak Rider	12,618	$	12 01	$	151,542
244	Power Factor Adjustment ($/kW) Summer	2,351	$	21 30	$	50,076
245	Power Factor Adjustment ($/kW) Winter	6,135	$	17.11	$	104,970
246	Power Factor Adjustment ($/kW) - Experimental Off-Peak Rider	4,889	$	12 01	$	58,717
247	Facilities Rental Charge	29,251		17 3292%	$	5,069
248	Four Corners Surcharge - Experimental Off-Peak Rider	1,358,604	$	0.00008	$	109
249	Four Corners Surcharge - Primary	160,290,764	$	0.00008	$	12,823
250	Transmission Voltage					
251	Customer Charge	12	$	200.00	$	2,400
252	Energy Charge ($/kWh) On-Peak	518,894	$	0 11529	$	59,823
253	Energy Charge ($/kWh) Off-Peak	8,704,124	$	0 00774	$	67,370
254	Demand Charge ($/kW) Summer	6,000	$	18 84	$	113,040
255	Demand Charge ($/kW) Winter	12,000	$	14.65	$	175,800
256	Power Factor Adjustment ($/kW) Summer	476	$	18 84	$	8,968
257	Power Factor Adjustment ($/kW) Winter	952	$	14 65	$	13,947
258	Four Corners Surcharge	9,223,018	$	0.00008	$	738
259	Total kWh Sales and Revenues	647,278,300			$	38,509,011
260						
261	Rate 26 - Petroleum Refinery Service Rate					
262	Customer Charge	12	$	684 00	$	8,208
263	Energy Charge (kWh) - Summer and Winter	334,025,355	$	0 00825	$	2,755,709
264	Demand Charge ($/kW) Summer	161,600	$	20 49	$	3,311,184
265	Demand Charge ($/kW) Winter	323,200	$	16 30	$	5,268,160
266	Power Factor Adjustment ($/kW) Summer	10,896	$	20 49	$	223,259
267	Power Factor Adjustment ($/kW) Winter	21,792	$	16 30	$	355,210
268	Facilities Rental Charge	221,591		17 3292%	$	38,400
269	Four Corners Surcharge	334,025,355	$	0.00004	$	13,361
270	Total kWh Sales and Revenues	334,025,355			$	11,973,491
271						
272	Rate 28 - Area Lighting Service Rate					
273	7,000 LUMENS 35ft 195W MV Overhead CO Wood Pole	912	$	13 16	$	12,002
274	11,000 LUMENS 35ft 250W MV Overhead CO Wood Pole	900	$	14 91	$	13,419

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
275	20,000 LUMENS 35ft 400W MV Overhead CO Wood Pole	312	$	18 87	$	5,887
276	8,500 Lumens 35ft Mnt Hgt 100W HPS Overhead CO Wood Pole	16,692	$	11 70	$	195,296
277	23,200 Lumens 35ft Mnt Hgt 250W HPS Overhead CO Wood Pole	26,880	$	15.70	$	422,016
278	50,000 Lumens 35ft Mnt Hgt 400W HPS Overhead CO Wood Pole	744	$	19 41	$	14,441
279	14,400 Lumens 35ft Mnt Hgt 150W HPS Overhead CO Wood Pole	408	$	13 19	$	5,382
280	9,500 LUMENS 100W HPS Floodlight on EXISTING POLE	10,032	$	7.45	$	74,738
281	27,500 LUMENS 250W HPS Floodlight on EXISTING POLE	9,060	$	11 27	$	102,106
282	50,000 LUMENS 400W HPS Floodlight on EXISTING POLE	23,568	$	14 62	$	344,564
283	119,500 LUMENS 1,000W HPS Floodlight on EXISTING POLE	13,632	$	28 47	$	388,103
284	38,000 LUMENS 35ft 400W MH Floodlight on EXISTING POLE	2,772	$	16.31	$	45,211
285	115,000 LUMENS 35ft 1,000W MH Floodlight on EXISTING POLE	4,776	$	28 55	$	136,355
286	9,500 LUMENS 35ft 100W HPS Floodlight on COMPANY POLE	5,436	$	12 32	$	66,972
287	27,500 LUMENS 35ft 250W HPS Floodlight on COMPANY POLE	2,736	$	16 38	$	44,816
288	50,000 LUMENS 35ft 400W HPS Floodlight on COMPANY POLE	12,192	$	19.74	$	240,670
289	119,500 LUMENS 35ft 1,000W HPS Floodlight on COMPANY POLE	1,896	$	36 33	$	68,882
290	119,500 LUMENS 45ft 1,000W HPS Floodlight on COMPANY POLE	11,712	$	37.51	$	439,317
291	38,000 LUMENS 35ft 400W MH Floodlight on COMPANY POLE	1,296	$	25.59	$	33,165
292	115,000 LUMENS 35ft 1,000W MH Floodlight on COMPANY POLE	1,020	$	37.81	$	38,566
293	115,000 LUMENS 45ft 1,000W MH Floodlight on COMPANY POLE	2,604	$	38 99	$	101,530
294	Four Corners Surcharge	27,182,227	$	0.00038	$	10,329
295	Total kWh Sales and Revenues	27,182,227			$	2,803,767
296						
297	Rate 30 - Electric Furnace Rate					
298	Customer Charge	12	$	240.00	$	2,880
299	Energy Charge ($/kWh) On-Peak	1,257,501	$	0 17068	$	214,630
300	Energy Charge ($/kWh) Off-Peak	17,171,953	$	0.00775	$	133,083
301	Demand Charge ($/kW) Summer	20,000	$	15 11	$	302,200
302	Demand Charge ($/kW) Winter	40,000	$	10 92	$	436,800
303	Power Factor Adjustment ($/kW) Summer	4,921	$	15.11	$	74,356
304	Power Factor Adjustment ($/kW) Winter	9,125	$	10 92	$	99,645
305	Four Corners Surcharge	18,429,454	$	0.00069	$	12,716
306	Total kWh Sales and Revenues	18,429,454			$	1,276,311
307						
308	Rate 31 - Military Reservation Service Rate					
309	Customer Charge	12	$	820.00	$	9,840
310	Energy Charge ($/kWh) On-Peak	17,913,025	$	0 12181	$	2,181,986
311	Energy Charge ($/kWh) Off-Peak	246,713,864	$	0 00775	$	1,912,032
312	Demand Charge ($/kW) Summer	168,000	$	20 21	$	3,395,280
313	Demand Charge ($/kW) Winter	336,000	$	16 02	$	5,382,720
314	Four Corners Surcharge	264,626,889	$	0 00021	$	55,572
315	Total kWh Sales and Revenues	264,626,889			$	12,937,430
316						
317	Rate 34 - Cotton Gin Service Rate					
318	Customer Charge	2	$	474 00	$	948
319	Customer Charge - Off Season - Small General Service	4	$	9 95	$	40
320	Customer Charge - Off Season - General Service	4	$	27.50	$	110
321	Energy Charge ($/kWh) Summer Sm General Service	-	$	0 05303	$	-
322	Energy Charge ($/kWh) Winter Sm General Service	20,520	$	0 03303	$	678
323	Energy Charge ($/kWh) Out of Season Sm General Service	840	$	0.11407	$	96
324	Energy Charge ($/kWh) Summer General Service	17,317	$	0.05303	$	918
325	Energy Charge ($/kWh) Winter General Service	1,540,179	$	0 03303	$	50,872
326	Energy Charge ($/kWh) Out Season General Service	24,883	$	0 06927	$	946
327	Demand Charge ($/kW) Summer - Sm General Service (Sept- Oct)	44	$	14.10000	$	620
328	Demand Charge ($/kW) Winter - Sm General Service (Nov - Apr)	186	$	14 10000	$	2,623
329	Demand Charge ($/kW) Out of Season Sm General Service	-	$	-	$	-

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
330	Demand Charge ($/kW) Summer - General Service (Sept - Oct)	320	$	14.10000	$	4,512
331	Demand Charge ($/kW) Winter - General Service (Nov - Apr)	4,071	$	14 10	$	57,401
332	Demand Charge ($/kW) Out of Season General Service	134	$	12.21	$	1,636
333	Four Corners Surcharge - Sm General Service	21,360	$	0 00166	$	35
334	Four Corners Surcharge - General Service	1,582,379	$	0 00166	$	2,627
335	Total kWh Sales and Revenues	1,603,739			$	124,062
336						
337	Rate 41 - City and County Service					
338	Secondary Voltage - Summer					
339	Customer Charge	11,376	$	18 82	$	214,096
340	Energy Charge ($/kWh) Summer, First 3,000 kWh	12,502,482	$	0 10817	$	1,352,393
341	Energy Charge ($/kWh) Summer, All Other kWh	124,722,325	$	0 02957	$	3,688,039
342	Demand Charge (kW)	441,396	$	20 15	$	8,894,129
343	Secondary Voltage - Winter					
344	Energy Charge ($/kWh) Winter, First 3,000 kWh	12,472,112	$	0.09071	$	1,131,345
345	Energy Charge ($/kWh) Winter, All Other kWh	94,364,532	$	0.01211	$	1,142,754
346	Demand Charge (kW)	348,053	$	16.73	$	5,822,927
347	Non-Metered Items	12	$	26.58	$	319
348	Primary Voltage - Summer					
349	Customer Charge	324	$	18.82	$	6,098
350	Energy Charge ($/kWh) Summer, First 3,000 kWh	486,000	$	0.10594	$	51,487
351	Energy Charge ($/kWh) Summer, All Other kWh	25,757,061	$	0 02896	$	745,924
352	Demand Charge (kW)	53,855	$	18 82	$	1,013,551
353	Primary Voltage - Winter					
354	Energy Charge ($/kWh) Winter, First 3,000 kWh	486,000	$	0.08884	$	43,176
355	Energy Charge ($/kWh) Winter, All Other kWh	18,919,125	$	0.01185	$	224,192
356	Demand Charge (kW)	44,248	$	15 40	$	681,419
357	Four Corners Surcharge - Secondary	244,061,450	$	0 00112	$	273,349
358	Four Corners Surcharge - Primary	45,648,186	$	0.00112	$	51,126
359	Total kWh Sales and Revenues	289,709,636			$	25,336,326
360						
361	Rate 45 - Supplemental Service for Cogeneration Rate					
362	Large Systems Primary (Large Power Service - Primary Voltage)					
363	Customer Charge	12	$	100.00	$	1,200
364	Demand Charge ($/kW) Summer	15,997	$	21 30	$	340,736
365	Demand Charge ($/kW) Winter	27,653	$	17 11	$	473,143
366	Energy Charge ($/kWh) On-Peak	1,805,720	$	0 11818	$	213,400
367	Energy Charge ($/kWh) Off-Peak	24,217,908	$	0 00793	$	192,048
368	Interconnection Charge	14,067		5.0614%	$	712
369	Four Corners Surcharge	26,023,628	$	0.00008	$	2,082
370	Total kWh Sales and Revenues	26,023,628			$	1,223,321
371						
372	Total Firm Service kWh and Revenues	5,812,108,751			$	484,658,116
373						
374	Non-Firm Service					
375	Rate 38 - Noticed Interruptible Power Service					
376	Primary Voltage					
377	Interruptible Demand Charge (kW)	80,571	$	4.19	$	337,592
378	Interruptible Energy Charge (kWh)	44,794,575	$	0.00448	$	200,680
379	Power Factor Adjustment ($/kW)	2,752	$	4 19	$	11,531
380	Transmission Voltage					
381	Interruptible Demand Charge (kW)	750,226	$	2.22	$	1,665,502
382	Interruptible Energy Charge (kWh)	317,821,664	$	0 00434	$	1,379,346
383	Power Factor Adjustment ($/kW)	112,750	$	2 22	$	250,305
384	Four Corners Surcharge	362,616,239	$	0 00008	$	29,009

EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE Q-7: PROOF OF REVENUE STATEMENT
SPONSOR: MANUEL CARRASCO
PREPARER: RENE F. GONZALEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units		Base Unit Rate		Base Rate Revenues
385	Total kWh Sales and Revenues	362,616,239			$	3,873,965
386						
387	Rate 47 - Backup Power Service for Cogeneration and Small Power Production Facilities					
388	Large Systems Primary (Large Power Service - Primary Voltage)					
389	Customer Charge	-	$	100.00	$	-
390	Demand Charge	-	$	21 30	$	-
391	Energy Charge ($/kWh) On-Peak	4,800	$	0 11818	$	567
392	Energy Charge ($/kWh) Off-Peak	93,600	$	0 00793	$	742
393	Delivery Service Charge	9,600	$	3 28	$	31,488
394	Four Corners Surcharge	98,400	$	0 00008	$	8
395	Total kWh Sales and Revenues	98,400			$	32,805
396						
397	Total Non-Firm kWh Sales and Revenues	362,714,639			$	3,906,770
398						
399	Total Firm and Non Firm kWh Sales and Revenues	6,174,823,390			$	488,564,886
400						
401	Miscellaneous Service Charges					
402	New Service Start - No Meter Reading Required (B)	2,949	$	17 75	$	52,345
403	New Service Start - Meter Reading Required (B)	70,379	$	24.00	$	1,689,096
404	New Service Start - No Existing Meter (Standard Rate) (B)	5,418	$	51.25	$	277,673
405	New Service Start - No Existing Meter (Non-Standard Rate) (B)	(1)	$	280 25	$	(280)
406	Energy Diversion Charge (B)	90	$	294 25	$	26,483
407	Meter Seal Replacement Charge (B)	0	$	8 75	$	-
408	Remote Meter Register Charge (DELETED)	0	$	-	$	-
409	No Access to Meter Charge (B)	0	$	12.50	$	-
410	"No Light" Service Call Charge (Standard Rate) (B)	177	$	28 25	$	5,000
411	"No Light" Service Call Charge (Non-Standard Rate) (B)	132	$	268 25	$	35,409
412	Non-Pay Reconnect Charge @ Meter - Next Day (B)	4,189	$	36 75	$	153,946
413	Non-Pay Reconnect Charge @ Meter - Same Day (B)	8,506	$	147.75	$	1,256,762
414	Non-Pay Reconnect Charge @ Pole (B)	25	$	147 00	$	3,675
415	Pulse Metering Equipment Installation (B)	0	$	262.75	$	-
416	Pulse Metering Equipment Repair (B)	0	$	77 25	$	-
417	Returned Payment Charge (B)	5,353	$	28.00	$	149,884
418	Requested Meter Test Charge (Single Phase) (B)	0	$	30.75	$	-
419	Requested Meter Test Charge (Three Phase) (B)	0	$	134.00	$	-
420	Record Name Change Charge (DELETED)	0	$	-	$	-
421	Temporary Overhead Connection Charge (B)	109	$	156 75	$	17,086
422	Temporary Underground Connection Charge (B)	708	$	156 75	$	110,979
423	Unable to Connect Requested New UG/OH Service (B)	460	$	76 75	$	35,305
424	Facilities Rental Charge (B)	0		1.3951%	$	-
425	Maintenance of Customer-Dedicated Facility Charge (B)	0		0.7050%	$	-
426	Maintenance of Customer-Owned Facility Charge (B)	0		3.5257%	$	-
427	Special Billing Analysis Charge (B)	0	$	68.50	$	-
428	Special Billing History Charge (B)	0	$	23.50	$	-
429	Non-Routine Miscellaneous Service Charges (B)	0		3.5257%	$	-
430	Out of Cycle Meter Reading Charge (B)	1	$	18.75	$	19
431	Total Miscellaneous Service Charges				$	3,813,380
432						
433	Other Electric Revenues					
434	Rent from Property				$	2,193,042
435	Other Electric Revenues - Wheeling					370,785
436	Transmission of Electricity Others					17,146,845
437	Forfeited Discounts					1,469,887
438	Other Sales Margins Retained by EPE					36,823,366
439	Total Other Electric Revenues				$	58,003,925

BASE RATE REVENUES UNDER CURRENT RATES

Line	Description	Billing Units	Base Unit Rate	Base Rate Revenues
440				
441	Total Base, Miscellaneous, and Other Electric Revenue at Current Rates			$ 550,382,191
442	Total Fuel Revenues, per WP/ A-3 Adjustment 2			$ 149,384,419
443	Total Revenues			$ 699,766,610

Totals may not match other schedules/workpapers due to rounding.

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
1	Rate 1 - Residential Service Rate					
2	Customer Charge - Non LIR	3,397,380	(21,684)	3,375,696	$ 10.85	$ 36,626,302
3	Customer Charge - Low Income Rider		-	116,523	$ (10.85)	$ (1,264,278)
4	Energy Charge ($/kWh) Summer Block 1 (0 - 600 kWh)	784,809,397	(3,787,225)	781,022,172	$ 0.10133	$ 79,140,977
5	Energy Charge ($/kWh) Summer Block 2 (All Other kWh)	507,626,093	(2,473,763)	505,152,330	$ 0.10633	$ 53,712,847
6	Energy Charge ($/kWh) Winter (All kWh)	830,456,920	(2,511,567)	827,945,353	$ 0.09133	$ 75,616,249
7	Total kWh Sales and Revenues	2,122,892,410	(8,772,555)	2,114,119,855		$ 243,832,097
8						
9	Rate 2 - Small General Service Rate					
10	Customer Charge	321,936		321,936	$ 14.83	$ 4,774,311
11	Energy Charge ($/kWh) - Summer (All kWh)	158,112,429		158,112,429	$ 0.10464	$ 16,544,885
12	Energy Charge ($/kWh) - Winter (All kWh)	119,205,513		119,205,513	$ 0.09464	$ 11,281,610
13	Total kWh Sales and Revenues	277,317,942		277,317,942		$ 32,600,805
14						
15	Rate 3 - Residential Distributed Generation Service Rate					
16	Customer Charge	-	21,684	21,684	$ 18.15	$ 393,565
17	Demand Charge ($/kW) Summer	-	64,182	64,182	$ 6.20	$ 397,928
18	Demand Charge ($/kW) Winter	-	39,999	39,999	$ 6.20	$ 247,994
19	Energy Charge ($/kWh) On-Peak	-	1,869,372	1,869,372	$ 0.31152	$ 582,347
20	Energy Charge ($/kWh) Off-Peak	-	19,159,509	19,159,509	$ 0.03040	$ 582,449
21	Total kWh Sales and Revenues (kWh Sales = Delivered kWh)	-	21,028,881	21,028,881		$ 2,204,283
22						
23	Rate 7 - Outdoor Recreational Lighting Service Rate					
24	Customer Charge - Secondary	2,328		2,328	$ 30.96	$ 72,075
25	Energy Charge ($/kWh) - Secondary Voltage (All kWh)	5,216,037		5,216,037	$ 0.10900	$ 568,533
26	Energy Charge ($/kWh) - Primary Voltage (All kWh)	102,509		102,509	$ 0.09351	$ 9,586
27	Total kWh Sales and Revenues	5,318,546		5,318,546		$ 650,193
28						
29	Rate 8 - Governmental Street Lighting Service Rate					
30	7,000 Lumens Single 175W MV Overhead CO 35ft Wood Pole	5,220		5,220	$ 16.27	$ 84,929
31	11,000 Lumens Single 250W MV Overhead CO 35ft Wood Pole	3,480		3,480	$ 18.57	$ 64,624
32	20,000 Lumens Single 400W MV Overhead CO 35ft Wood Pole	360		360	$ 23.78	$ 8,561
33	20,000 Lumens Double 400W MV Overhead CO 35ft Wood Pole	-		-	$ -	$ -
34	119,500 Lumens 1,000W HPS Overhead CO 30ft Steel Pole	24		24	$ 55.70	$ 1,337
35	119,500 Lumens 1,000W HPS Underground CO 30ft Steel Pole	96		96	$ 90.91	$ 8,727
36	50,000 Lumens 450W HPS Overhead CO 30ft Steel Pole	996		996	$ 48.66	$ 48,465
37	20,000 Lumens Single 400W MV Overhead CO 30ft Steel Pole	852		852	$ 34.01	$ 28,977
38	20,000 Lumens Double 400W MV Overhead CO 30ft Steel Pole	108		108	$ 47.75	$ 5,157
39	11,000 Lumens Wall Mount 250W MV Non-CO Frwy Lghtng	264		264	$ 9.94	$ 2,624
40	20 000 Lumens 40ft Mount Hght 400W MV Non-CO Frwy Lghtng	168		168	$ 13.68	$ 2,298
41	60,000 Lumens 50ft Mount Hght 1,000W MV Non-CO Frwy Lghtng	-		-	$ -	$ -
42	7,000 Lumens 35ft 175W MV UG or OH Non-CO Wood Pole Res Srvc	108		108	$ 7.54	$ 814
43	16,000 Lumens Wall Mount 150W HPS Non-CO System Frwy Lghtng	6,888		6,888	$ 7.92	$ 54,553
44	23,200 Lumens Wall Mount 250W HPS Non-CO System Frwy Lghtng	1,224		1,224	$ 10.67	$ 13,060
45	23,200 Lumens 40ft MntHgt 250W HPS Non-CO System Frwy Lghtng	-		-	$ -	$ -
46	50,000 Lumens 50ft MntHgt 400W HPS Non-CO System Frwy Lghtng	25,932		25,932	$ 14.66	$ 380,163
47	50,000 Lumens 150ft Tower-Climbing 400W HPS Non-CO Sys Frwy	-		-	$ -	$ -
48	50,000 Lumens 150ft Tower-Lowering 400W HPS Non-CO Sys Frwy	1,344		1,344	$ 15.47	$ 20,792
49	Obstruction Lights Incandescent 40ft 116W HPS NonCO Sys Frwy	72		72	$ 4.54	$ 327
50	150 FT Tower 116W HPS Non-CO Sys Frwy	36		36	$ 5.44	$ 196
51	16,000 Lumens Wall Mount 150W HPS Non-CO Sys Arterial	-		-	$ -	$ -
52	23,200 Lumens Wall Mount 250W HPS Non-CO Sys Arterial	-		-	$ -	$ -
53	23,200 Lumens 40ft Mnt Hgt 250W HPS Non-CO Sys Arterial	4,236		4,236	$ 11.59	$ 49,095

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
54	50,000 Lumens 50ft Mnt Hgt 400W HPS Non-CO Sys Arterial	7,620		7,620	$ 16.68	$ 127,102
55	8,500 Lumens 30ft MntHgt 100W HPS UG/OH Non-CO Pole Res	42,876		42,876	$ 5.60	$ 240,106
56	14 400 Lumens 30ft MntHgt 150W HPS UG/OH Non-CO Pole Res	-		-	$ 7.03	$ -
57	23 200 Lumens 30ft MntHgt 250W HPS UG/OH Non-CO Pole Res	31,176		31,176	$ 10.78	$ 336,077
58	8,500 Lumens 35ft 100W HPS OH NonCO Stand Fxtr CO Wood Pole	29,856		29,856	$ 7.55	$ 225,413
59	14,400 Lumens 35ft 150W HPS OH NonCO Stand Fxtr CO Wood Pole	30,348		30,348	$ 9.13	$ 277,077
60	23,200 Lumens 35ft 250W HPS OH NonCO Stand Fxtr CO Wood Pole	11,448		11,448	$ 11.60	$ 132,797
61	23,200 Lumens Dbl 250W HPS OH NonCO Stand Fxtr CO Wood Pole	132		132	$ 20.61	$ 2,721
62	50,000 Lumens 50ft 450W HPS OH NonCO Stand Fxtr CO Wood Pole	228		228	$ 15.91	$ 3,627
63	8,500 Lumens 35ft Mnt Hgt 100W HPS Overhead CO Wood Pole	12,084		12,084	$ 15.44	$ 186,577
64	14,400 Lumens 35ft Mnt Hgt 150W HPS Overhead CO Wood Pole	7,848		7,848	$ 16.76	$ 131,532
65	23,200 Lumens 35ft Mnt Hgt 250W HPS Overhead CO Wood Pole	4,800		4,800	$ 19.62	$ 94,176
66	50 000 Lumens 50ft Mnt Hgt 400W HPS Overhead CO Wood Pole	1,656		1,656	$ 28.21	$ 46,716
67	5,300 Lumens 70W Ornament HPS Non-CO Operated Maintained	-		-	$ 1.89	$ -
68	14,400 Lumens 150W Ornament HPS Non-CO Operated Maintained	-		-	$ 3.44	$ -
69	14,400 Lumens 175W Ornament HPS Non-CO Operated Maintained	5,868		5,868	$ 3.74	$ 21,946
70	16,000 Lumens 250W Ornament HPS Non-CO Operated Maintained	252		252	$ 4.46	$ 1,124
71	State of Texas Lighting 100W HPS Non-CO Owned Roadway Illum	2,952		2,952	$ 2.31	$ 6,819
72	State of Texas Lighting 150W HPS Non-CO Owned Roadway Illum	1,368		1,368	$ 3.59	$ 4,911
73	State of Texas Lighting 250W HPS Non-CO Owned Roadway Illum	16,452		16,452	$ 5.75	$ 94,599
74	State of Texas Lighting 400W HPS Non-CO Owned Roadway Illum	27,732		27,732	$ 13.70	$ 379,928
75	21W-30W LED - Street Light - Non Company Owned and Maint Sys	-		-	$ 0.44	$ -
76	31W-40W LED - Street Light - Non Company Owned and Maint Sys	84,948		84,948	$ 0.61	$ 51,818
77	41W-50W LED - Street Light - Non Company Owned and Maint Sys	312		312	$ 0.79	$ 246
78	51W-60W LED - Street Light - Non Company Owned and Maint Sys	-		-	$ 0.96	$ -
79	65W LED replacing 7K Lumens Single Overhead CO 35ft Wd Pole	16,224		16,224	$ 12.55	$ 203,611
80	65W LED replacing 8 5K Lumen 35ft Mnt Hgt Ovrhd CO Wd Pole	1,368		1,368	$ 12.26	$ 16,772
81	61W-70W LED - Street Light - Non Company Owned and Maint Sys	27,444		27,444	$ 1.14	$ 31,286
82	71W-80W LED - Street Light - Non Company Owned and Maint Sys	744		744	$ 1.31	$ 975
83	81W-90W LED - Street Light - Non Company Owned and Maint Sys	-		-	$ 1.49	$ -
84	91W-100W LED - Street Light - Non Company Owned and Maint Sy	13,440		13,440	$ 1.67	$ 22,445
85	100W LED replacing 11K Lumen Single Overhead CO 35ft Wd Pole	756		756	$ 15.69	$ 11,862
86	100W LED replacing 20K Lumen Single Overhead CO 35ft Wd Pole	540		540	$ 18.60	$ 10,044
87	101W-110W LED - Street Light - Non Company Owned and Maint S	29,484		29,484	$ 1.84	$ 54,251
88	116W LED replacing 23 2K Lumen 35ft Mnt Hgt Ovrhd CO Wd Pole	456		456	$ 16.74	$ 7,633
89	111W-130W LED - Street Light - Non Company Owned and Maint S	12,348		12,348	$ 2.10	$ 25,931
90	131W-150W LED - Street Light - Non Company Owned and Maint S	1,560		1,560	$ 2.45	$ 3,822
91	151W-170W LED - Street Light - Non Company Owned and Maint S	13,116		13,116	$ 2.80	$ 36,725
92	171W-190W LED - Street Light - Non Company Owned and Maint S	-		-	$ 3.15	$ -
93	191W-210W LED - Street Light - Non Company Owned and Maint S	-		-	$ 3.51	$ -
94	211W-230W LED - Street Light - Non Company Owned and Maint S	-		-	$ 3.86	$ -
95	231W-250W LED - Street Light - Non Company Owned and Maint S	-		-	$ 4.21	$ -
96	251W-270W LED - Street Light - Non Company Owned and Maint S	-		-	$ 4.56	$ -
97	32W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	60		60	$ 2.05	$ 123
98	32W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	60		60	$ -	$ -
99	65W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	3,672		3,672	$ 2.05	$ 7,528
100	65W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	3,672		3,672	$ -	$ -
101	95W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	672		672	$ 2.05	$ 1,378
102	95W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	672		672	$ -	$ -
103	100W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	948		948	$ 2.05	$ 1,943
104	100W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	960		960	$ -	$ -
105	116W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	1,440		1,440	$ 2.05	$ 2,952
106	116W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	1,968		1,968	$ -	$ -
107	159W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	444		444	$ 2.05	$ 910

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
108	159W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole Lamps	456		456	$ -	$ -
109	252W LED - Street Light - NCO Fixture & Lamp on CO Dist Pole	2,592		2,592	$ -	$ -
110	Total kWh Sales and Revenues	33,230,643		33,230 643		$ 3,580,202
111						
112	Rate 9 - Governmental Traffic Signal Service Rate					
113	4 Unit School Flasher 14W 351ABHrs LED Traffic Signal	-		-	$ 78.00	$ -
114	2 Unit School Flashers 14W 351ABHrs LED Traffic Signal	-		-	$ 0 36	$ -
115	4 Unit School Flasher 14W 790ABHrs LED Traffic Signal	-		-	$ 78 00	$ -
116	2 Unit School Flasher 14W 790ABHrs LED Traffic Signal	11,592		11,592	$ 0 36	$ 4,173
117	2 U School Flasher 103W 351ABhrs Incandescent Traffic Signal	-		-	$ 2 68	$ -
118	2 U School Flasher 133W 790ABhrs Incandescent Traffic Signal	24		24	$ 3 48	$ 84
119	2 Unit Walk Light 9W 18HrsN 6HrsF LED Traffic Signal	-		-	$ 0 30	$ -
120	2 Unit Walk Light 9W 24Hrs LED Traffic Signal	58,488		58,488	$ 0 30	$ 17,546
121	2 Unit Flashing 14W 24Hr LED Traffic Signal	96		96	$ 0 45	$ 43
122	2 Unit Flashing - 24 Hours - 103 Watts	-		-	$ 2 68	$ -
123	3 Lamp Head 14W 18HrsN 6HrsF LED Trafic Signals	-		-	$ 0 44	$ -
124	4 Lamp Head 14W 18HrsN 6HrsF LED Traffic Signals	-		-	$ 0 78	$ -
125	5 Lamp Head 14W 24Hrs LED Traffic Signal	9,216		9,216	$ 0 78	$ 7,188
126	1 Unit Flashing 14W 24Hrs LED Traffic Signal	3,168		3,168	$ 0 23	$ 729
127	3 Lamp Head 14W 24Hrs LED Traffic Signal	75,612		75,612	$ 0 45	$ 34,025
128	4 Lamp Head 14W 24Hrs LED Traffic Signal	2,484		2,484	$ 0 78	$ 1,938
129	30 Watt Controller 30W 24Hrs Incandescent Traffic Signal	576		576	$ 0 78	$ 449
130	3 Lamp Head 61W 24Hrs Incandescent Traffic Signal	-		-	$ 1 59	$ -
131	4 Lamp Head 61W 24Hrs incandescent Traffic Signal	-		-	$ 1 59	$ -
132	2 Unit Walk Light 61W 24Hrs Incandescent Traffic Signal	-		-	$ 1 59	$ -
133	100 Watt Controller 100W 24Hrs LED Traffic Signal	8,064		8,064	$ 3 33	$ 26,853
134	2 Unit Walk Light 103W 24Hrs Incandescent Traffic Signal	-		-	$ 2 68	$ -
135	4 Lamp Head 103W 18HrsN 6HrsF Incandescent Traffic Signal	-		-	$ 2 68	$ -
136	1 Unit Flashing 103W 24Hrs Incandescent Traffic Signal	-		-	$ 2 68	$ -
137	2 Unit Walk Lght 103W 18HrsN 6HrsF Incandescent Traffic Sign			-	$ 2 68	$ -
138	3 Lamp Head 103W 18HrsN 6HrsF Incandescent Traffic Signal			-	$ 2 68	$ -
139	3 Lamp Head 103W 24Hrs Incandescent Traffic Signal			-	$ 2 68	$ -
140	3 Lamp Head 133W 24Hrs Incandescent Traffic Signal			-	$ 3 48	$ -
141	4 Lamp head 133W 24Hrs Incandescent Traffic Signal			-	$ 3 48	$ -
142	5 Lamp Head 133W 24Hrs Incandescent Traffic Signal			-	$ 3 48	$ -
143	1 Unit Flashing 133W 24Hr Incandescent Traffic Signal	-		-	$ 3 48	$ -
144	3 Lamp Head 133W 18HrsN 6HrsF Incandenscent Traffic Signal	-		-	$ 3 48	$ -
145	4 Lamp Head 133W 18HrsN 6HrsF Incandescent Traffic Signal	-		-	$ 3 48	$ -
146	Total kWh Sales and Revenues	2,629,032		2,629,032		$ 93,029
147						
148	Rate 11 - Municipal Pumping Service Rate					
149	Customer Charge	2,136	(2,136)	-	$ -	$ -
150	Energy Charge ($/kWh) - Summer (All kWh) - Secondary	6,111,864	(6,111,864)	-	$ -	$ -
151	Energy Charge ($/kWh) - Summer (All kWh) - Primary	-		-	$ -	$ -
152	Energy Charge ($/kWh) - Winter (All kWh) - Secondary	9,764,089	(9,764,089)	-	$ -	$ -
153	Energy Charge ($/kWh) - Winter (All kWh) - Primary	-	-	-	$ -	$ -
154	Total kWh Sales and Revenues	15,875,952	(15,875,952)	-		$ -
155						
156	Rate 11 - TOU Municipal Pumping Service Rate					
157	Customer Charge	2,903	2,136	5,039	$ 105 09	$ 529,549
158	Energy Charge On-Peak - ($/kWh) - Secondary	3,344,041	543,196	3,887,237	$ 0 21746	$ 845,319
159	Energy Charge Shoulder-Peak - ($/kWh) - Secondary	5,630,819	914,652	6,545,471	$ 0 11163	$ 730,671
160	Energy Charge Off-Peak - ($/kWh) - Secondary	88,761,282	14,418,104	103,179,386	$ 0 04631	$ 4,778,237

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
161	Energy Charge On-Peak - ($/kWh) - Primary	1,788,457	-	1,788,457	$ 0.21506	$ 384,626
162	Energy Charge Shoulder-Peak - ($/kWh) - Primary	2,715,828	-	2,715,828	$ 0.10923	$ 296,650
163	Energy Charge Off-Peak - ($/kWh) - Primary	41,359,347	-	41,359,347	$ 0.04391	$ 1,816,089
164	Total kWh Sales and Revenues	143,599,774	15,875,952	159,475,726		$ 9,381,140
165						
166	Rate 15 - Electrolytic Refining Service Rate					
167	Customer Charge	12		12	$ 400.00	$ 4,800
168	Energy Charge On-Peak ($/kWh) - Summer	2,528,602		2,528,602	$ 0.16231	$ 410,417
169	Energy Charge Off-Peak ($/kWh) - Summer	53,252,796		53,252,796	$ 0.00493	$ 262,536
170	Demand Charge ($/kW) - Summer	40,000		40,000	$ 17.00	$ 680,000
171	Demand Charge ($/kW) - Winter	80,000		80,000	$ 12.87	$ 1,029,600
172	Interconnection Charge	79,957		79,957	4.6334%	$ 3,705
173	Total kWh Sales and Revenues	55,781,398		55,781,398		$ 2,391,058
174						
175	Rider - Water Heating Rider (Rider to Rate Nos 01, 02 and 24)					
176	Customer Charge	55,680		55,680	$ 2.81	$ 156,547
177	Energy Charge ($/kWh) - Summer (All kWh)	3,551,937		3,551,937	$ 0.10553	$ 374,836
178	Energy Charge ($/kWh) - Winter (All kWh)	5,111,639		5,111,639	$ 0.09553	$ 488,315
179	Total kWh Sales and Revenues	8,663,576		8,663,576		$ 1,019,698
180						
181	Rate 22 - Irrigation Service Rate					
182	Customer Charge	1,668		1,668	$ 27.08	$ 45,169
183	Energy Charge On-Peak ($/kWh) - Summer	359,523		359,523	$ 0.46882	$ 168,552
184	Energy Charge Off-Peak ($/kWh) - Summer	4,686,017		4,686,017	$ 0.05677	$ 266,025
185	Total kWh Sales and Revenues	5,045,540		5,045,540		$ 479,746
186						
187	Rate 24 - General Service Rate					
188	Secondary Voltage					
189	Customer Charge	79,596		79,596	$ 30.32	$ 2,413,351
190	Energy Charge ($/kWh) - Summer (0 - 200 kW hours)	463,299,988		463,299,988	$ 0.07652	$ 35,451,715
191	Energy Charge ($/kWh) - Summer (next 150 kW hours)	243,904,114		243,904,114	$ 0.05570	$ 13,585,459
192	Energy Charge ($/kWh) - Summer (all addt'l kW hours)	147,668,013		147,668,013	$ 0.04055	$ 5,987,938
193	Demand Charge ($/kW) - Summer	2,425,947		2,425,947	$ 13.52	$ 32,798,803
194	Winter Energy Charge (0 - 200 kW hours) ($/kWh)	361,374,459		361,374,459	$ 0.03772	$ 13,631,045
195	Winter Energy Charge (next 150 kW hours) ($/kWh)	179,100,973		179,100,973	$ 0.02748	$ 4,921,695
196	Winter Energy Charge (all addt'l kW hours) ($/kWh)	100,821,059		100,821,059	$ 0.02003	$ 2,019,446
197	Demand Charge ($/kW) - Winter	1,964,497		1,964,497	$ 9.43	$ 18,525,207
198	Primary Voltage					
199	Customer Charge	480		480	$ 30.32	$ 14,554
200	Energy Charge ($/kWh) - Summer (0 - 200 kW hours)	9,975,363		9,975,363	$ 0.06093	$ 607,799
201	Energy Charge ($/kWh) - Summer (next 150 kW hours)	6,714,655		6,714,655	$ 0.04434	$ 297,728
202	Energy Charge ($/kWh) - Summer (all addt'l kW hours)	4,245,165		4,245,165	$ 0.03228	$ 137,034
203	Demand Charge ($/kW) - Summer	52,832		52,832	$ 12.13	$ 640,852
204	Energy Charge ($/kWh) - Winter (0 - 200 kW hours)	8,439,486		8,439,486	$ 0.03005	$ 253,607
205	Energy Charge ($/kWh) - Winter (next 150 kW hours)	5,139,914		5,139,914	$ 0.02190	$ 112,564
206	Energy Charge ($/kWh) - Winter (all addt'l kW hours)	2,191,520		2,191,520	$ 0.01597	$ 34,999
207	Demand Charge ($/kW) - Winter	43,323		43,323	$ 8.04	$ 348,317
208	Total kWh Sales and Revenues	1,532,874,710		1,532,874,710		$ 131,782,111
209						
210	Rate 25 - Large Power Service Rate					
211	Secondary Voltage					
212	Customer Charge	1,088		1,088	$ 200.00	$ 217,600
213	Energy Charge ($/kWh) On-Peak	37,550,929		37,550,929	$ 0.11533	$ 4,330,749
214	Energy Charge ($/kWh) Off-Peak	438,854,984		438,854,984	$ 0.00521	$ 2,286,434

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
215	Total Annual kW - Summer	368 639		368,639	$ 23 11	$ 8,519 247
216	Total Annual kW - Winter	678,396		678,396	$ 18 98	$ 12,875,956
217	Primary Voltage (Includes Rate 45)					
218	Customer Charge	240		240	$ 200	$ 48,000
219	Energy Charge ($/kWh) On-Peak	13,689,944		13,689,944	$ 0 11265	$ 1,542 172
220	Energy Charge ($/kWh) Off-Peak	172,624,449		172,624,449	$ 0 00509	$ 878,658
221	Demand Charge ($/kW) Off-Peak Maximum - Experimental Off-Peak Rider	17,507		17,507	$ 12 06	$ 211,134
222	Total Annual kW - Summer	141,683		141,683	$ 22 45	$ 3,180,783
223	Total Annual kW - Winter	264,847		264,847	$ 18 32	$ 4,851,997
224	Energy Charge ($/kWh) Time-of-Use Maximum - Experimental Off-Peak Rider	1,358,604		1,358,604	$ 0 00509	$ 6,915
225	Facilities Rental Charge	79,886		79,886	16 6098%	$ 13,269
226	Transmission Voltage					
227	Customer Charge	12		12	$ 400 00	$ 4,800
228	Energy Charge ($/kWh) On-Peak	518,894		518,894	$ 0 10989	$ 57,021
229	Energy Charge ($/kWh) Off-Peak	8,704,124		8,704,124	$ 0 00497	$ 43,259
230	Total Annual kW - Summer	6 476		6 476	$ 18 96	$ 122,785
231	Total Annual kW - Winter	12,952		12,952	$ 14 83	$ 192,078
232	Total kWh Sales and Revenues	673,301,928		671,960,831		$ 39,382,860
233						
234	Rate 26 - Petroleum Refinery Service Rate					
235	Customer Charge	12		12	$ 721.28	$ 8,655
236	Energy Charge (kWh) - Summer and Winter	334,025,355		334,025,355	$ 0 00520	$ 1,736,932
237	Demand Charge ($/kW) Summer	172,496		172,496	$ 23 71	$ 4,090,432
238	Demand Charge ($/kW) Winter	344,992		344 992	$ 19 58	$ 6,754,943
239	Facilities Rental Charge	221,591		221 591	16 6098%	$ 36,806
240	Total kWh Sales and Revenues	334,025,355		334,025,355		$ 12,627,768
241						
242	Rate 28 - Area Lighting Service Rate					
243	7,000 LUMENS 35ft 195W MV Overhead CO Wood Pole	912		912	$ 13 17	$ 12,011
244	11,000 LUMENS 35ft 250W MV Overhead CO Wood Pole	900		900	$ 14 92	$ 13,428
245	20,000 LUMENS 35ft 400W MV Overhead CO Wood Pole	312		312	$ 18.89	$ 5,894
246	8,500 Lumens 35ft Mnt Hgt 100W HPS Overhead CO Wood Pole	16,692		16,692	$ 11 71	$ 195,463
247	23,200 Lumens 35ft Mnt Hgt 250W HPS Overhead CO Wood Pole	26,880		26,880	$ 15 72	$ 422,554
248	50,000 Lumens 35ft Mnt Hgt 400W HPS Overhead CO Wood Pole	744		744	$ 19 43	$ 14,456
249	14,400 Lumens 35ft Mnt Hgt 150W HPS Overhead CO Wood Pole	408		408	$ 13 21	$ 5,390
250	9,500 LUMENS 100W HPS Floodlight on EXISTING POLE	10,032		10,032	$ 7 31	$ 73,334
251	27,500 LUMENS 250W HPS Floodlight on EXISTING POLE	9,060		9,060	$ 11 25	$ 101,925
252	50,000 LUMENS 400W HPS Floodlight on EXISTING POLE	23,568		23,568	$ 14 61	$ 344,328
253	119,500 LUMENS 1,000W HPS Floodlight on EXISTING POLE	13,632		13,632	$ 28 48	$ 388,239
254	38,000 LUMENS 35ft 400W MH Floodlight on EXISTING POLE	2,772		2,772	$ 15 99	$ 44,324
255	115,000 LUMENS 35ft 1,000W MH Floodlight on EXISTING POLE	4,776		4,776	$ 28 53	$ 136,259
256	9,500 LUMENS 35ft 100W HPS Floodlight on COMPANY POLE	5,436		5,436	$ 12.33	$ 67,026
257	27,500 LUMENS 35ft 250W HPS Floodlight on COMPANY POLE	2,736		2,736	$ 16 40	$ 44,870
258	50,000 LUMENS 35ft 400W HPS Floodlight on COMPANY POLE	12,192		12,192	$ 19 76	$ 240,914
259	119,500 LUMENS 35ft 1,000W HPS Floodlight on COMPANY POLE	1,896		1,896	$ 35 63	$ 67,554
260	119,500 LUMENS 45ft 1,000W HPS Floodlight on COMPANY POLE	11,712		11,712	$ 36 78	$ 430,767
261	38,000 LUMENS 35ft 400W MH Floodlight on COMPANY POLE	1,296		1,296	$ 25 09	$ 32,517
262	115,000 LUMENS 35ft 1,000W MH Floodlight on COMPANY POLE	1,020		1 020	$ 37 08	$ 37,822
263	115,000 LUMENS 45ft 1,000W MH Floodlight on COMPANY POLE	2,604		2,604	$ 38.24	$ 99,577
264	Total kWh Sales and Revenues	27,182,227		27,182,227		$ 2,778,653
265						
266	Rate 30 - Electric Furnace Rate					
267	Customer Charge	12		12	$ 240.00	$ 2,880
268	Energy Charge ($/kWh) On-Peak	1,257,501		1,257,501	$ 0 16786	$ 211,084

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
269	Energy Charge ($/kWh) Off-Peak	17,171,953		17,171,953	$ 0 00494	$ 84,829
270	Demand Charge ($/kW) Summer	24,921		24,921	$ 17.14	$ 427,146
271	Demand Charge ($/kW) Winter	49,125		49,125	$ 13 01	$ 639,116
272	Total kWh Sales and Revenues	18,429,454		18,429,454		$ 1,365,056
273						
274	Rate 31 - Military Reservation Service Rate					
275	Customer Charge	12		12	$ 820 00	$ 9 840
276	Energy Charge ($/kWh) On-Peak	17,913,025		17,913,025	$ 0 11939	$ 2,138,636
277	Energy Charge ($/kWh) Off-Peak	246,713,864		246,713,864	$ 0 00494	$ 1,218,766
278	Demand Charge ($/kW) Summer	168,000		168,000	$ 20 78	$ 3 491,040
279	Demand Charge ($/kW) Winter	336,000		336,000	$ 16 65	$ 5,594,400
280	Total kWh Sales and Revenues	264,626,889		264,626,889		$ 12,452,683
281						
282	Rate 34 - Cotton Gin Service Rate					
283	Customer Charge	2		2	474	$ 948
284	Customer Charge - Off Season - Small General Service	4		4	$ 14 83	$ 59
285	Customer Charge - Off Season - General Service	4		4	$ 30 32	$ 121
286	Energy Charge ($/kWh) - Summer	17,317		17,317	$ 0 05502	$ 953
287	Energy Charge ($/kWh) - Winter	1,560 699		1,560,699	$ 0 03502	$ 54,656
288	Energy Charge ($/kWh) - Summer, Sm Comm	840		840	$ 0 10464	$ 88
289	Energy Charge ($/kWh) - Summer, Gen Svc, Blk 1	23,483		23,483	$ 0 07652	$ 1 797
290	Energy Charge ($/kWh) - Summer, Gen Svc, Blk 2	600		600	$ 0 05570	$ 33
291	Energy Charge ($/kWh) - Summer Gen Svc, Blk 3	800		800	$ 0 04055	$ 32
292	Demand Charge ($/kW)	134		134	$ 11 71	$ 1,569
293	Demand Charge ($/kW) - General Service	4,621		4,621	$ 13.52	$ 62,476
294	Total kWh Sales and Revenues	1,603,739		1,603,739		$ 122,733
295						
296	Rate 41 - City and County Service					
297	Secondary Voltage - Summer					
298	Customer Charge	11,388		11,388	$ 22 63	$ 257,710
299	Demand Charge (May - Oct)	441 396		441,396	$ 24 47	$ 10,800,960
300	Energy Charge (May - Oct) - First 200 kWh/kW	94,582,422		94,582,422	$ 0 04239	$ 4,009,514
301	Energy Charge (May - Oct) - Next 150 kWh/kW	33,712,957		33,712,957	$ 0 03739	$ 1,260,586
302	Energy Charge (May - Oct) - All Other kWh	8,929,427		8,929,427	$ 0.03	$ 289,240
303	Demand Charge (Nov - Apr)	348,053		348,053	$ 20 36000	$ 7,086,359
304	Energy Charge (Nov - Apr) - First 200 kWh/kW	77,663,063		77,663,063	$ 0 03239	$ 2,515,642
305	Energy Charge (Nov - Apr) - Next 150 kWh/kW	24,383,077		24,383,077	$ 0.02739	$ 667,895
306	Energy Charge (Nov - Apr) - All Other kWh	4,790,504		4,790,504	$ 0 02239	$ 107,268
307	Primary Voltage - Summer			-		$ -
308	Customer Charge	324		324	$ 22 63	$ 7,332
309	Demand Charge (May - Oct)	53,855		53,855	$ 22 88	$ 1,232,202
310	Energy Charge (May - Oct) - First 200 kWh/kW	11,422,340		11,422,340	$ 0.03881	$ 443,301
311	Energy Charge (May - Oct) - Next 150 kWh/kW	7,291,562		7,291,562	$ 0 03381	$ 246,528
312	Energy Charge (May - Oct) - All Other kWh	7,529,159		7,529,159	$ 0 03	$ 216,915
313	Demand Charge (Nov - Apr)	44,248		44,248	$ 18 76000	$ 830,092
314	Energy Charge (Nov - Apr) - First 200 kWh/kW	9,251,060		9,251,060	$ 0 02881	$ 266,523
315	Energy Charge (Nov - Apr) - Next 150 kWh/kW	5,752,853		5,752,853	$ 0 02381	$ 136,975
316	Energy Charge (Nov - Apr) - All Other kWh	4,401,212		4,401,212	$ 0 01881	$ 82,787
317	Total kWh Sales and Revenues	289,709,636		289,709,636		$ 30,457,831
318						
319	Total Firm Service kWh and Revenues	5,812,108,750	12,256,326	291,313,375		$ 527,201,945
320						
321	Non-Firm Service					
322	Rate 38 - Noticed Interruptible Power Service					
323	Primary Voltage					
324	Interruptible Demand Charge (kW)	83,323			$ 4.97	$ 414,115
325	Interruptible Energy Charge (kWh)	44,794,575			$ 0 00506	$ 226,661
326	Transmission Voltage					
327	Interruptible Demand Charge (kW)	862,976			$ 1 93	$ 1,665,544
328	Interruptible Energy Charge (kWh)	317,821,664			$ 0 00494	$ 1,570,039

EL PASO ELECTRIC COMPANY
2017 TEXAS RATE CASE FILING
SCHEDULE Q-7. PROOF OF REVENUE STATEMENT
SPONSOR: MANUEL CARRASCO
PREPARER RENE F. GONZALEZ
FOR THE TEST YEAR ENDED SEPTEMBER 30, 2016

BASE RATE REVENUES UNDER PROPOSED RATES

Line	Description	Billing Units	Billing Units Migrated from Rate 01 and 11	Total Billing Units	Base Unit Rate	Base Rate Revenues
329	Total kWh Sales and Revenues	362,616,239				$ 3,876,359
330						
331	Rate 47 - Backup Power Service for Cogeneration and Small Power Production Facilities					
332	Large Systems Primary (Large Power Service - Primary Voltage)					
333	Customer Charge	-			$ 200 00	$ -
334	On-Peak Energy	4,800			$ 0 11265	$ 541
335	Off-Peak Energy	93,600			$ 0 00509	$ 476
336	Delivery Service Charge	9,600			$ 3 49	$ 33,504
337	Total kWh Sales and Revenues	98,400				$ 34,521
338						
339		362,714,639				$ 3,910,880
340	Total Non-Firm kWh Sales and Revenues					
341		6,174 823 389				$ 531,112,825
342	Total Firm and Non Firm kWh Sales and Revenues					
343						
344	Misc New Service Start - No Meter Reading Required (B)	2,949			$ 17 75	$ 52,345
345	New Service Start - Meter Reading Required (B)	70,379			$ 24 00	$ 1,689,096
346	New Service Start - No Existing Meter (Standard Rate) (B)	5,418			$ 51 25	$ 277,673
347	New Service Start - No Existing Meter (Non-Standard Rate) (B)	(1)			$ 280 25	$ (280)
348	Energy Diversion Charge (B)	90			$ 294 25	$ 26,483
349	Meter Seal Replacement Charge (B)	0			$ 8 75	$ -
350	Remote Meter Register Charge (DELETED)	0			$ -	$ -
351	No Access to Meter Charge (B)	0			$ 12 50	$ -
352	"No Light" Service Call Charge (Standard Rate) (B)	177			$ 28 25	$ 5,000
353	"No Light" Service Call Charge (Non-Standard Rate) (B)	132			$ 268 25	$ 35,409
354	Non-Pay Reconnect Charge @ Meter - Next Day (B)	4,189			$ 36 75	$ 153,946
355	Non-Pay Reconnect Charge @ Meter - Same Day (B)	8,506			$ 147 75	$ 1,256,762
356	Non-Pay Reconnect Charge @ Pole (B)	25			$ 142.00	$ 3,550
357	Pulse Metering Equipment Installation (B)	0			$ 262.75	$ -
358	Pulse Metering Equipment Repair (B)	0			$ 77 25	$ -
359	Returned Payment Charge (B)	5,353			$ 28 00	$ 149,884
360	Requested Meter Test Charge (Single Phase) (B)	0			$ 30 75	$ -
361	Requested Meter Test Charge (Three Phase) (B)	0			$ 134 00	$ -
362	Record Name Change Charge (DELETED)	0			$ -	$ -
363	Temporary Overhead Connection Charge (B)	109			$ 160.50	$ 17,495
364	Temporary Underground Connection Charge (B)	708			$ 160 50	$ 113,634
365	Unable to Connect Requested New UG/OH Service (B)	460			$ 76 75	$ 35,305
366	Facilities Rental Charge (B)	0			1 3951%	$ -
367	Maintenance of Customer-Dedicated Facility Charge (B)	0			0 7050%	$ -
368	Maintenance of Customer-Owned Facility Charge (B)	0			3 5257%	$ -
369	Special Billing Analysis Charge (B)	0			$ 68 50	$ -
370	Special Billing History Charge (B)	0			$ 23 50	$ -
371	Non-Routine Miscellaneous Service Charges (B)	0			3 5257%	$ -
372	Out of Cycle Meter Reading Charge (B)	1			$ 18 75	$ 19
373						$ 3,816,318
374	Total Miscellaneous Service Charges					
375	Other Electric Revenues					
376	Rent from Property					$ 2,193,042
377	Other Electric Revenues - Wheeling					370,785
378	Transmission of Electricity Others					17,146,845
379	Forfeited Discounts					1,469,887
380	Other Sales Margins Retained by EPE					36,823,366
381						$ 58,003,925
382	Total Other Electric Revenues					
383						
384	Total Base, Miscellaneous, and Other Electric Revenue at Current Rates					$ 592,933,068
385	Total Fuel Revenues per WP/ A-3 Adjustment 2					$ 149 384,419
386	Total Revenues					$ 742,317,487

Totals may not match other schedules/workpapers due to rounding.

The following files are not convertible:

Exhibit JP-1.xlsx
Exhibit JP-2, 3, 4.xlsx
Exhibit JP-5.xlsx
Exhibit JP-6, 7, 9.xlsx
Exhibit JP-8.xlsx
Figures 1-4.XLSM

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ELECTRIC UTILITY
RATE FILING PACKAGE
FOR GENERATING UTILITIES

Public Utility Commission of Texas

September 9, 1992

SCHEDULE P

Table of Contents

Schedule P: Class Cost of Service Analysis

The utility shall file an embedded cost of service study at an equal rate of return and workpapers necessary to support such a study. Schedules P-1 through P-11 (inclusive) shall also be filed on IBM-compatible computer diskettes in Lotus 123 worksheets or ".prn" files, or in ASCII format. The study shall show adjustments from present adjusted to proposed levels. In showing the adjustments from present adjusted levels to proposed levels, the present adjusted amounts shall be consistent with adjusted accounting and load data found in the current rate filing package.

Schedule P-1: Rate of Return

Rate class data included in the summaries shall include, but not necessarily be limited to, the following information:

1. Revenues from sales of electricity.
2. Other revenues.
3. Fuel factor revenues.
4. O&M expenses.
5. Depreciation and amortization expenses.
6. Taxes other than income taxes.
7. Provision for deferred taxes (where applicable).
8. Net investment tax credit adjustment (if applicable).
9. Federal income tax (if applicable).
10. Gross plant.
11. Reserve for depreciation.
12. Construction work in progress.
13. Plant held for future use.
14. Materials and supplies inventory.
15. Working cash.
16. Prepayments.

18. Accumulated deferred income taxes (if applicable).

19. Customer advances.

20. Property insurance and accident reserve.

21. Other items as needed.

Note (1): In certain cases, there may exist some ambiguity regarding the existing rate schedule under which customers in a proposed class should be billed. Such ambiguity would arise, for example, when existing classes "A" and "B" are combined into a proposed class "C." When the choice of the existing rate schedule is not clear, the utility shall make assumptions regarding the most appropriate existing rate schedule for use in this section's analysis. Any assumptions made shall be clearly stated in this section.

Note (2): Accounts 501, 518, and 547 should be separated into reconcilable and nonreconcilable cost components.

Schedule P-1.1: Proposed Rate Schedules/Proposed Rate Classes

Provide summaries of the rate of return and relative rate of return under proposed rate schedules using proposed rate classes.

Schedule P-1.2: Existing Rate Schedules/Proposed Rate Classes

Provide summaries of the rate of return and relative rate of return under existing rate schedules using proposed rate classes.

Schedule P-1.3: Existing Rate Schedules/Existing Rate Classes

Provide summaries of the rate of return and relative rate of return under existing rate schedules using existing rate classes.

Schedule P-1.4: Proposed Rate Schedules/Existing Rate Classes

Provide summaries of the rate of return and relative rate of return under proposed rate schedules using existing rate classes.

Schedule P-1.5: Financial Data for Non-Investor-Owned Utilities

Non-investor-owned electric utilities shall also provide the following financial data by rate class:

1. Total margins.

3. Times interest earned ratio (TIER).

4. Debt service coverage (DSC).

Schedule P-2: Allocation of Revenue Deductions to Proposed Rate Classes

Provide the allocation of the following to proposed rate classes:

1. O&M expense by FERC primary account.

2. Depreciation expense, consistent with the presentation in Schedules D-4.

3. Any other revenue deductions.

Note: All deductions from income used to develop return shall be included in the revenue deductions.

Note: All allocations shall be labeled in such a manner as to identify the basis for each cost allocation, and all allocators shall be thoroughly defined.

Schedule P-3: Allocation of Rate Base to Proposed Rate Classes

Provide the allocation of the following to proposed rate classes:

1. Gross plant or net plant by FERC primary account.

2. If gross plant was provided in response to 1., provide accumulated depreciation and amortization by major function and, if available, by FERC primary account.

3. Construction work in progress by major function.

4. Materials and supplies inventory by major function.

5. Working cash by major function.

6. Prepayments by major function.

7. Any other rate base items.

Note: All rate base components set forth on Schedule P-1 shall be identified on this schedule.

Note: All allocations shall be labeled in such a manner as to identify the basis for each cost allocation, and all allocators shall be thoroughly defined.

Schedule P-4: Separation of Expenses

Provide a separation of expenses by classification (e.g., demand, energy, customer). Identify revenue-related and directly assigned expenses as such.

Note: Care should be taken to ensure that the assignment of all expenses from accounts to classification is identified.

Note: Every classification of accounts shall be identified and labeled in such a manner as to identify the basis for each cost assignment. For example, it is necessary to identify and label the assignment of Account 583, Overhead Line Expense, to the demand and customer classifications, if applicable.

Schedule P-5: Separation of Rate Base

Provide a separation of each functional component of the rate base by classification (e.g., demand, energy, and customer). Identify revenue-related and directly assigned items as such.

Note: See notes applicable to Schedule P-4.

Schedule P-6: Unit Cost Analysis

Provide the following for return levels at present rates and proposed rates:

1. Unit component costs by classification by proposed rate classes.

2. Unit component costs by classification by existing rate classes.

Note: Component costs refer to classified revenue requirement by rate class. For example, dollars of demand, customer, and energy revenue requirement associated with the standard residential rate class.

Note: Unit component costs refer to average component costs expressed in dollars per billing kilowatt or in dollars per billing KVA (if applicable), per kilowatt-hour, and per customer.

Schedule P-7: Allocation Factors

1. Provide a listing of allocation factors and associated data which shall include the following information for every factor used to assign costs to a rate class:

   a. The designation of the allocation factor used in Schedules P-1, P-2, and P-3.

   b. A narrative description of the allocation factor if code designation is used.

   c. The relative (decimal representations of percentages) amounts constituting the

d. The absolute amounts constituting the factors. That is, the kW, kWh, LOLP, number of customers, or dollars, etc., that are used as the numerators and divisors in calculating the allocation factors in c. above.

2. Provide workpapers and a narrative explanation to support the calculation of each allocation factor listed in 1. above. To the extent that key operating statistics provided in Schedule O are employed in directly developing the allocation factors, workpapers shall be referenced directly to this data.

3. For each direct assignment of costs, provide a narrative description of the justification for such assignment.

Schedule P-8: Classification Factors

1. Provide a listing of classification factors which shall include the following information for every factor used to assign costs from a single account to more than one classification:

   a. The designation of the classification factor.

   b. The percent of total costs assigned to each classification.

2. Provide workpapers and a narrative explanation of the derivation of the classification factors provided in 1. above, as well as the rationale for the selection of each factor.

Schedule P-9: Demand and Energy Loss Factors

Provide a listing of the demand and energy loss factors used in the cost of service study, by rate class and/or customer class and by voltage level.

Schedule P-10: Payroll Expense Distribution

The test year adjusted payroll expense shall be reported by functional group and by FERC primary account.

Schedule P-11: Distribution Plant Study

The utility shall provide a distribution plant study by FERC primary account, showing:

1. Percentage split between primary and secondary cost components.

2. Percentage split between demand and customer cost components.

3. Number of transformers, their KVA ratings, and their respective original and/or replacement costs.

4. Number of meters and their original and/or replacement cost by rate group and by type of

5. Meter installation original and/or replacement cost by rate class and by type of meter.

Information supplied in this schedule may represent estimates if actual data is not available.

Schedule P-12: Support for Production Allocation Methodology

Provide the rationale for the selection of each allocation methodology used in the cost of service. The rationale may consist of a cost justification, a special study, and/or a narrative explanation with supporting workpapers.

Schedule P-13: Summary of Changes in Allocation Factors

Provide a summary schedule showing the allocation factors which differ from those approved in the utility's last rate case.

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	[illegible]	[illegible] 4
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x4[4]
524	Miscellaneous Nuclear Power Expenses	[illegible]	-
525	Rents	x	-

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES[1]

Maintenance

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

CLASSIFICATION OF EXPENSES[1]

FERC Uniform System of Account	Description	Demand Related	Energy Related
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

VII. SUMMARY AND CONCLUSION

A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

The following files are not convertible:

Table 1.xlsx
Table 2.xlsx

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