El Paso Electric

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EMAILED

September 16, 2021

Ms. Melanie Sandoval
Records Bureau
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269

Re: Compliance Filing Pursuant to IRP Rule, 17.7.3 NMAC
El Paso Electric Company's Integrated Resource Plan

Dear Ms. Sandoval:

Attached for filing please find El Paso Electric Company's ("EPE") Integrated Resource Plan ("IRP") for the period 2021-2040. This compliance filing is made pursuant to Section 9 of the Commission's IRP Rule, 17.7.3 NMAC which requires that certain electric utilities file an IRP, along with an action plan, every three years.

Distribution of the IRP, along with a copy of this letter, is being conducted through the following actions:

- EPE has posted an electronic copy of its IRP on EPE's website at www.epelectric.com/company/regulatory/2020-2021-new-mexico-integrated-resource-plan-public-meetings.
- Copies are being served electronically to the NMPRC Chairman and Commissioners, General Counsel of the NMPRC, the New Mexico Attorney General and counsel of record and pro se parties in EPE's most recent general rate case, NMPRC Case No. 20-00104-UT, and all active participants in EPE's Public Advisory Group, including NMPRC Staff members who participated in the IRP Public Advisory Group.

Thank you for your assistance in this matter.

Very truly yours,

/s/Nancy B. Burns
Nancy B. Burns
Deputy-General Counsel
El Paso Electric Company

Enclosures
Service List

EL PASO ELECTRIC
2021 INTEGRATED RESOURCE PLAN

The Electric Company®
El Paso Electric

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I. EXECUTIVE SUMMARY

EPE presents this Integrated Resource Plan ("IRP" or "Plan") pursuant to the requirements of the New Mexico Public Regulation Commission's ("Commission" or "NMPRC") IRP Rule, 17.7.3 NMAC ("IRP Rule"), the New Mexico Efficient Use of Energy Act, NMSA 1978, § 62-17-1 *et seq*. ("EUEA"), and the New Mexico Renewable Energy Act, NMSA 1978, §62-16-1 *et seq*. ("REA").[1] This IRP, like our 2009, 2012, 2015 and 2018 IRPs, discusses EPE's integrated resource planning process (the "Planning Process") and develops an integrated resource portfolio to safely, reliably and cost-effectively meet the electricity needs of EPE's customers for the next twenty years. Unlike past IRPs, this IRP addresses New Mexico's 2019 Renewable Energy Act amendments, including New Mexico's amended renewable portfolio standard ("RPS"), which includes the following targets for renewable and carbon-free energy:

- 80% of all retail sales of electricity in New Mexico from renewable energy by 2040; and
- 100% of all retail sales of electricity in New Mexico from zero carbon resources by 2045.

EPE's carbon footprint is among the lowest one-third of the utility industry due to its ownership of Palo Verde nuclear generation and the fact EPE exited from coal generation in 2016. Table 1 shows a comparison of output emissions for EPE, the US Power Sector, the Western Energy Coordinating Council ("WECC"), New Mexico, and Texas.

Table 1. Comparison of 2019 Output Emissions

2019 Output Emissions	CO_{2e} (lbs/MWh)
El Paso Electric	543
U.S. Power Sector	884
WECC Southwest	957
New Mexico	1327
Texas	913

U.S. EPA, 2021. Emissions & Generation Resource Integrated Database (eGRID) at https://www.epa.gov/egrid/summary-data

This IRP provides a pathway for EPE to reach New Mexico's 100 percent zero carbon requirements through a cost-effective integrated resource portfolio which safely and reliability serves EPE's New Mexico customers.

[1] In addition, this IRP is consistent with the Stipulation resolving protested issues in EPE's Commission-accepted 2015 IRP approved by Commission Final Order in Case No 15-00241-UT.

To assist with the development of a full system resource plan which meets EPE's multi-jurisdictional obligations, EPE engaged Energy+Environmental Economics ("E3") to provide modeling analyses, including an assessment of EPE's planning reserve margin ("PRM"). EPE also engaged Burns and McDonnell to provide life extension analyses for units planned for retirement through 2026. Additionally, to assess impacts of decarbonization through 2040, EPE conducted a preliminary grid reliability study. Further, EPE conducted additional modeling to address New Mexico's REA requirements based on a New Mexico load and resource analysis.

The IRP analyses resulted in the following four portfolios: 1) Total System Least Cost ("LC"); 2) Least Cost + NM Dedicated Resources ("LC+REA"); 3) Separate System Planning ("SSP") with Gas; and 4) SSP with no Gas.

The portfolios are described below and in E3's Report appended to this IRP and incorporated herein by reference.

IRP MODELING AND INITIAL TOTAL SYSTEM LEAST COST PORTFOLIO

The IRP develops an integrated resource portfolio to meet the energy needs of EPE customers for the next twenty years in a safe, reliable, and most cost-effective manner. Within the IRP, various types of resource technology types including both, renewable and conventional energy, are considered and integrated to accomplish an optimal portfolio for EPE customers. Resource options modeled include solar photovoltaic ("PV"), wind, battery storage, conventional gas generation, biomass, geothermal, and demand side management ("DSM"). Conventional gas resources modeled are assumed to be hydrogen fuel capable. EPE utilized NREL renewable resource potential maps, shown in Figure 1, to identify geographical sites closest to EPE's system for potential solar, wind and geothermal resources. Transmission upgrade costs between the resource locations and EPE's load pockets were considered as costs associated with those resource options.

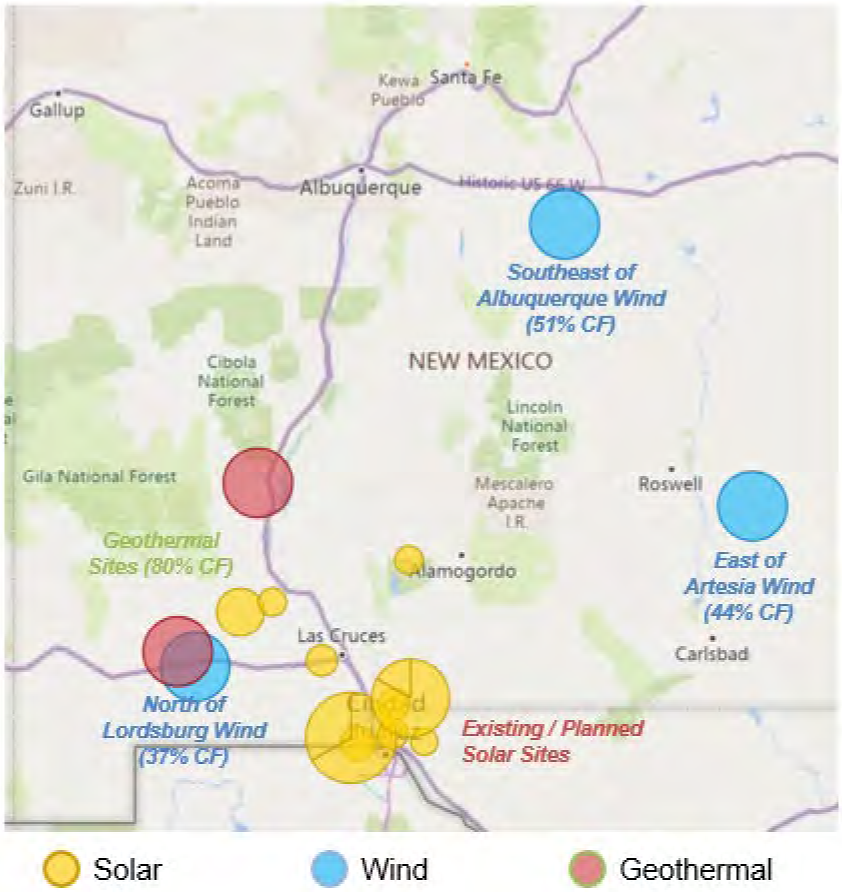


Figure 1. EPE Renewable Resource Geographical Locations

Two E3 proprietary models were utilized to carry out the IRP modeling analyses. First, E3's RECAP model was utilized for assessing resource adequacy and contributions of resources toward ensuring resource adequacy. The RECAP model estimates effective load carrying capability ("ELCC") values for the different resource types and also assesses the loss of load expectation ("LOLE") for the system based on the statistical variability of load, variable energy resource availability, and the forced outages of all resources and import transmission lines. Through this process, EPE elected to implement the industry standard of one loss of load event every ten years (i.e., 0.1 LOLE) to maintain best practice in system reliability planning. EPE plans to shift to the 1 in 10 target over the twenty-year horizon in a phased approach.

Second, E3's RESOLVE capacity expansion planning model was used to determine the optimal integrated demand-side and supply-side portfolio for the utility system. RESOLVE is a linear program model which allows it to analyze resource options and combination of resource options to identify the most cost-effective portfolio. This includes the ability to evaluate the combination of storage with solar and wind as well as the synergies that exist between solar and wind resources.

In addition, RESOLVE can assess the impacts of various scenarios and sensitivities based on total plan costs by imposing renewable energy targets, decarbonization targets or various sensitivities to inputs such as a carbon tax or fuel cost levels.

The IRP's resulting total system portfolio of resource additions, by type for future years, which meets New Mexico's REA targets, is shown in Table 2.

Table 2. Total System Least Cost + REA Portfolio Incremental Resource Additions (MW)

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*126*	*1*	*283*	*607*	*179*	*487*
Gas New	-	-	-	*141*	*134*	*108*
Gas 5-yr Extension	*74*	*313*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	*159*	-	*251*	*689*	*306*	*624*
Wind	*203*	-	-	-	*28*	*69*

The Total System Least Cost Portfolio does not impose any constraints beyond the reliability requirements and results in the optimal cost-effective resource portfolio before considering REA requirements or jurisdictional allocation. The battery storage and conventional gas generation resources provide needed flexibility to the system to complement the solar and wind resources which are variable and intermittent in nature. The actual resource additions in the future will be determined by the results of competitive requests for proposals and may differ based on future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards.

The IRP's resulting total installed capacity by resource type for EPE's system, existing plus new resources, which meets New Mexico's REA targets, is shown in Table 3.

Table 3. Total System Least Cost + REA Portfolio
Installed Existing Plus New Resource Capacity (MW)

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*176*	*177*	*460*	*1,067*	*1,246*	*1,682*
BTM Solar	*80*	*108*	*166*	*221*	*289*	*368*
DR	*56*	*61*	*71*	*81*	*93*	*93*
Gas	*1,531*	*1,531*	*1,395*	*1,075*	*1,208*	*1,317*
Geothermal	-	-	-	-	-	-
Nuclear	*622*	*622*	*622*	*622*	*622*	*622*
Solar	*544*	*544*	*795*	*1,414*	*1,693*	*2,037*
Wind	*203*	*203*	*203*	*203*	*232*	*300*

TOTAL SYSTEM DECARBONIZATION SCENARIOS

To assess options for attaining New Mexico's REA requirements and renewable integration for the total system, EPE expanded the IRP analysis to include portfolios that provided higher renewable energy integration and a higher carbon free energy mix for its total system energy needs. This was accomplished by imposing carbon reduction targets ranging from 20% to 100% by 2040and considering resource portfolio scenarios that included 100% carbon free energy by the year 2040. Table 4 summarizes the system decarbonization scenarios.

Table 4. System Decarbonization Scenarios

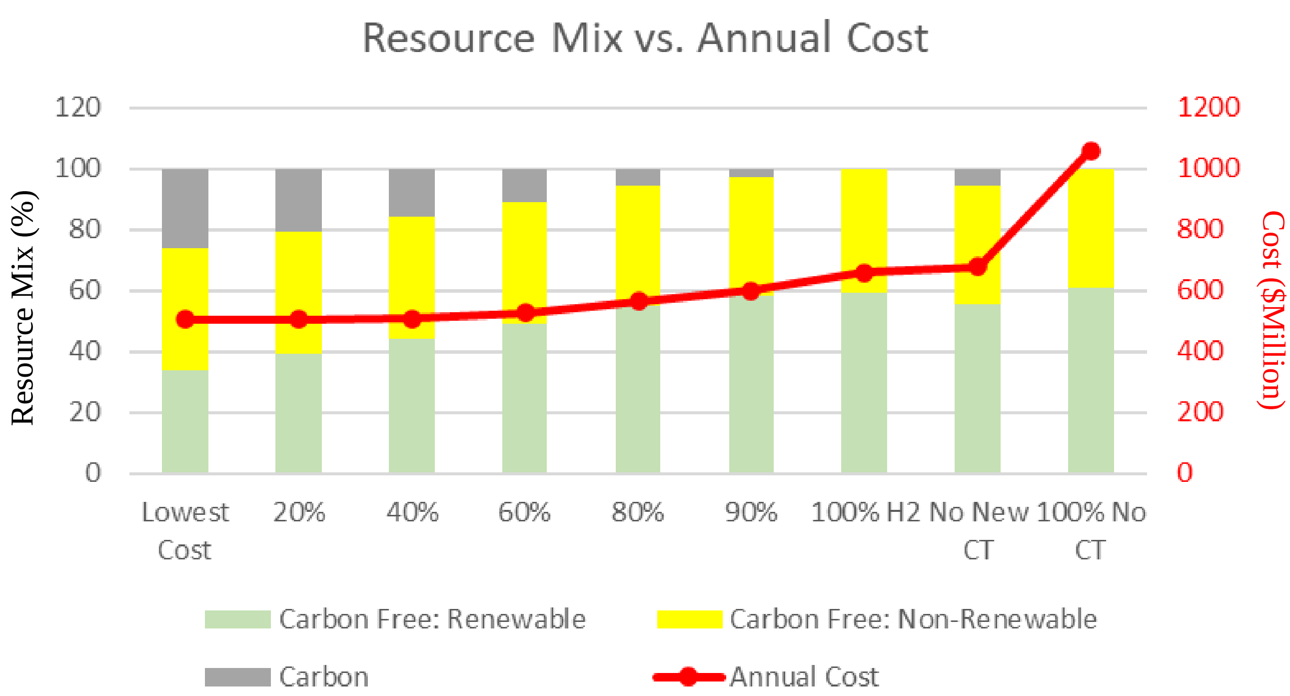
PORTFOLIO NAME	PORTFOLIO DESCRIPTION	CARBON FREE (%)	RENEWABLE (%)
Lowest Cost	Meets State RPS in Aggregate	74	34
20%	20% Carbon Emission Reduction by 2040	79	40
40%	40% Carbon Emission Reduction by 2040	84	44
60%	60% Carbon Emission Reduction by 2040	89	49
80%	80% Carbon Emission Reduction by 2040	94	55
90%	90% Carbon Emission Reduction by 2040	97	58
100% H2	100% Carbon Emission Reduction by 2040 with Hydrogen Available as a Zero-Carbon Fuel	100	59
No New CT	No New Combustion Turbines after 2024	94	55
100% No CT	100% Carbon Emission Reduction by 2040 with Only Renewables (Existing Nuclear)	100	61

As noted in Table 4, the decarbonization study results in a maximum renewable energy resource mix of approximately 50-60% by 2040. Separate evaluations of system reliability identified two factors that affect renewable integration on EPE's system: 1) transmission grid stability needs which require the use of dispatchable combustion generation for the last 10-15% of energy mix (which may be in the form of hydrogen fuel in the future); and 2) EPE's existing carbon-free, clean Palo Verde Generating Station ("PVGS") energy which currently provides approximately 45-50% of customer energy needs system wide.

The cost impact and customer affordability for greater renewable energy integration was also assessed by the study. The relationship between renewable energy integration and cost in year

2040 is illustrated in Figure 2. Cost increases are greater for the higher clean energy portfolios illustrated on the right. Specifically, the costs are greater above the 80% clean energy mix.

Figure 2. Annual Cost of Decarbonization Scenarios for 2040



The Total System Least Cost Portfolio provides sufficient renewable resources to meet both New Mexico's RPS and Texas' renewable requirements in the aggregate. However, this portfolio falls short of meeting New Mexico's requirements when proportionally allocating renewable resources between the Texas and New Mexico jurisdictions (approximately 80/20 allocation). Additionally, given the significant cost increase for total system 100 percent carbon free attainment, and lack of Texas mandate, it became necessary to assess jurisdictional planning options for addressing New Mexico's REA requirements while separately meeting Texas' resource planning requirements. EPE and E3 developed three jurisdictional modeling options to evaluate the most cost-effective manner for EPE to comply with New Mexico's REA requirements.

JURISDICTIONAL ANALYSIS AND LEAST COST PORTFOLIO

Because the initial model runs were performed on a total system basis, it was necessary to assess RPS impacts on a jurisdictional basis. EPE opted to evaluate the jurisdictional impacts by utilizing the Total System Least Cost Portfolio as the starting point. The jurisdictional analysis evaluated three different approaches to meeting New Mexico's REA requirements, which resulted in three New Mexico specific resource portfolios. Table 5 summarizes the three jurisdictional scenarios that were evaluated.

Table 5. New Resource Jurisdictional Allocation Options

	Least Cost ("LC")	**Least Cost + REA Resources** ("LC+REA")	**Separate System Planning** ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

1. **Option-1.** Least Cost Option - System Portfolio Allocated Proportionally (~80/20) and REC Transfer.

   Under this option, all new resources are allocated on a jurisdictional basis, inclusive of gas, and renewable energy. Once allocated, New Mexico's RPS is met through renewable energy delivered to EPE's system from: (1) renewable energy and renewable energy credits ("RECs") assigned to EPE's New Mexico jurisdiction; (2) existing dedicated New Mexico RPS resources and associated RECs; and (3) additional RECs without the associated renewable energy assigned to EPE's New Mexico jurisdiction. This option assumes the transfer of stand-alone RECs from EPE's Texas jurisdiction to EPE's New Mexico jurisdiction, an allocation of new gas capacity to New Mexico, which could be converted to run on a higher share of hydrogen fuel in the future, and no allocation of PVGS Unit 3 to New Mexico.

2. **Option 2.** Least Cost Plus REA Resources - System Portfolio Allocated Proportionally plus New Mexico Dedicated Resources.

   Under this option, all new resources are allocated on a jurisdictional basis, except for new gas which is 100 percent allocated to Texas. Additionally, to meet New Mexico's RPS and capacity requirements, RESOLVE reoptimized to select New Mexico dedicated renewable and capacity resources to meet New Mexico's jurisdictional requirements. Importantly, this scenario allows capacity pooling and dispatch benefits for system dispatch optimization. Under this scenario, REA compliance is assessed based on annual retail sales, allowing system gas resources to supply New Mexico energy needs when required, provided there is sufficient renewable and zero-carbon energy on an annual basis. This scenario is most comparable with past practice except for the exclusion of new gas resources.

3. **Option 3.** Separate Systems for New Mexico and Texas.

   This approach is based on a separate New Mexico portfolio and a separate Texas portfolio. This scenario segregates EPE's system planning and identifies a New Mexico REA compliant portfolio without any jurisdictional allocated new resources, rather, new resources would be dedicated to specific jurisdictions. Additionally, this approach assumes no capacity pooling between New Mexico and Texas, nor does it include joint system dispatch optimization. It also assesses New Mexico REA compliance on an hourly, as opposed to annual, basis. Therefore, without the leveraging of resources between jurisdictions, the New Mexico cost is higher because additional renewable resources and battery storage must be added to ensure hourly balancing and resource adequacy for New Mexico. This scenario was run both with and without the assumed use of hydrogen combustion generation. As indicated below, the scenario without hydrogen fuel options results in a higher cost.

   Additionally, EPE's preliminary grid reliability study has only assessed the impacts of an 80 percent carbon free scenario through 2040, and exclusive reliance on inverter-based technologies has not yet been determined viable under a 100 percent carbon free scenario. This may be addressed in the future through continued technology advancements for both inverter-based resources and grid devices.

The resulting capacity, annual generation, and resource mix for each of the scenarios for Total System and New Mexico jurisdictional basis are shown in Figure 3a and Figure 3b.

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Figure 3a. Total System & New Mexico Capacity Allocation Comparison for 2040

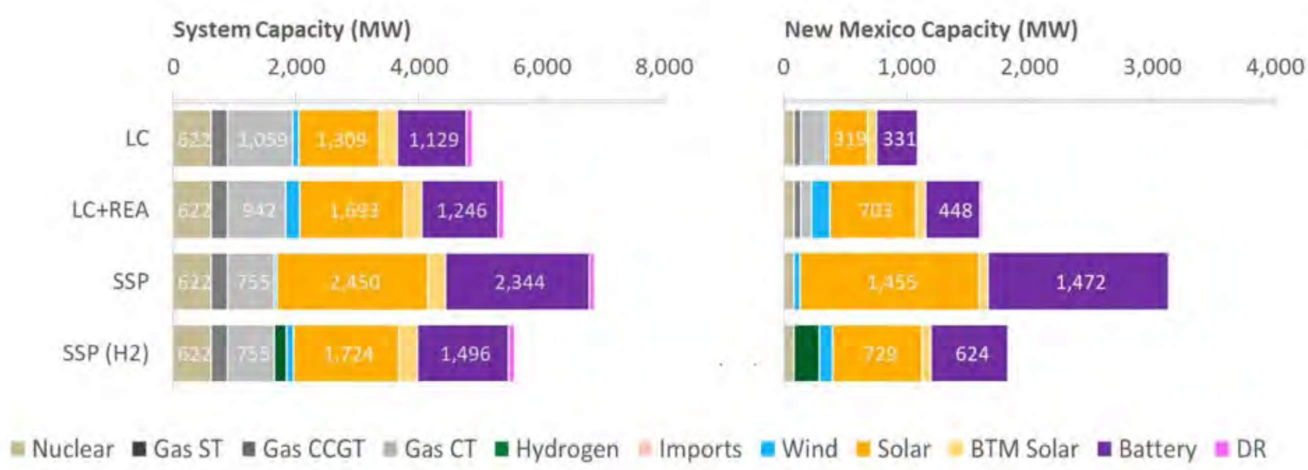
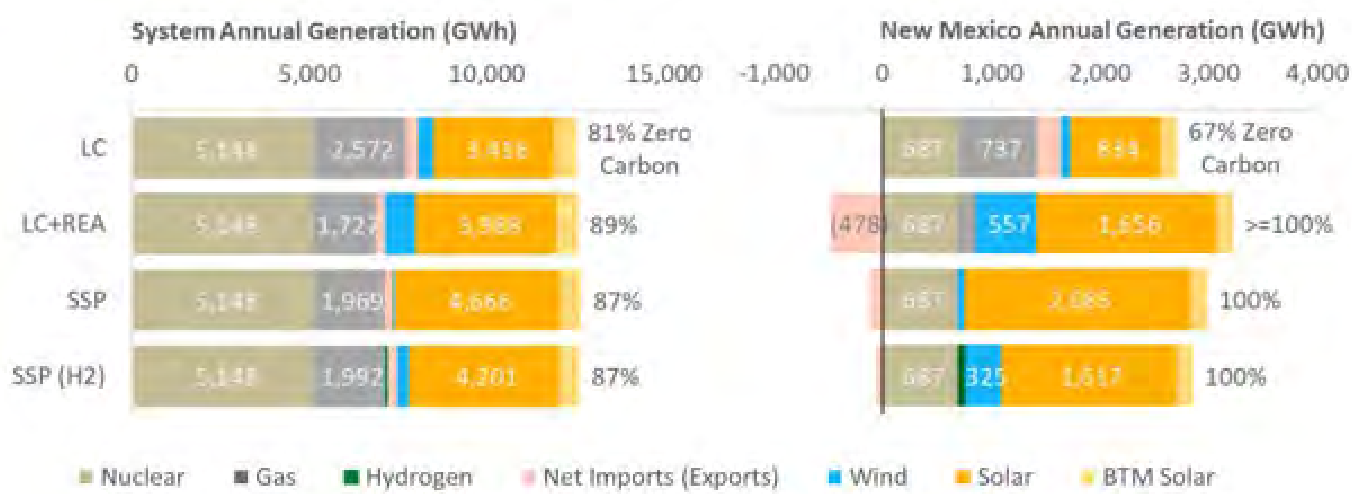


Figure 3b. Total System & New Mexico Annual Generation Allocation for 2040



The cost differential between the various jurisdictional approaches to REA compliance are illustrated over the planning horizon in Figure 4.

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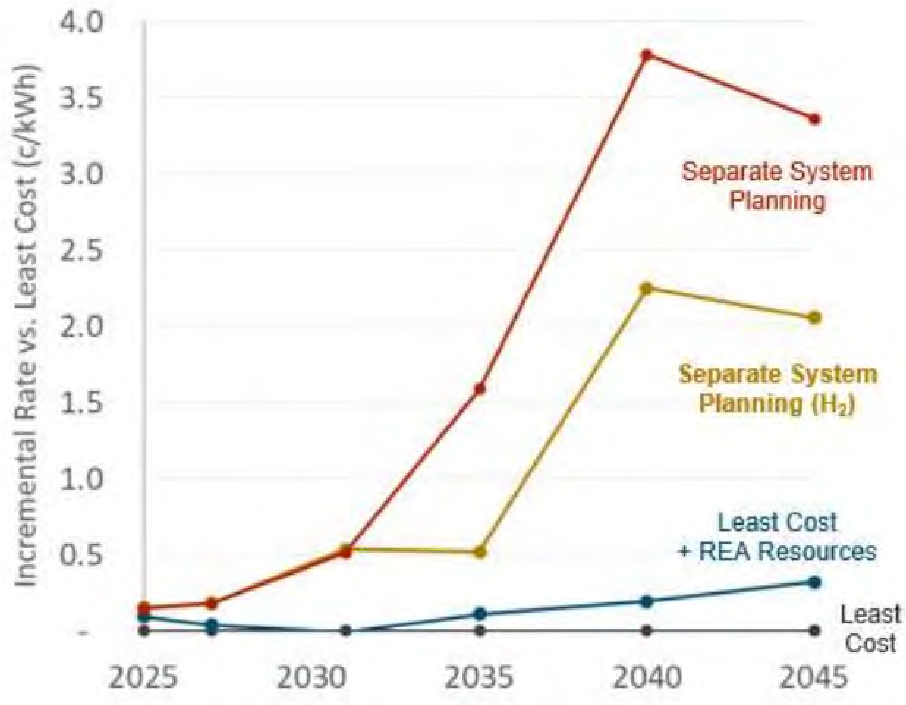
Figure 4. New Mexico Customer Rate Impact (Relative to Least Cost Case)



Option 1 presents challenges due to the required transfer of stand-alone RECs between EPE's jurisdictions and the inclusion of new gas plant additions for the New Mexico jurisdiction. Due to these challenges, EPE presents Options 2 and 3 as the most cost-effective jurisdictional options. Both address EPE's multi-jurisdictional planning requirements including the New Mexico REA requirements and the Texas lowest cost portfolio requirements.

Option 2 assumes that new system resources will be proportionally allocated to each jurisdiction. The benefits apparent in this scenario, as compared to the Separate System Planning scenario, result from load and resource diversity for capacity pooling and joint system dispatch of Texas and New Mexico resources while adhering to New Mexico's REA requirements. It is important to note that this scenario still requires each jurisdiction, New Mexico and Texas, to acquire sufficient capacity to meet their respective demand and reliability needs. However, it also allows for total system dispatch to optimize both jurisdictional resources to the benefit of both states. As discussed above, this scenario assumes the ability to at times utilize system gas resources to serve New Mexico customers in the event of renewable or carbon free resource energy output unavailability.

Option 3 assumes separate resource planning to address jurisdictional planning requirements. This scenario provides New Mexico the most resource planning autonomy to meet New Mexico's renewable and clean energy standards. Option 3 costs more, however, because the benefits associated with capacity pooling and load diversity during optimal dispatch of system-wide resources would not be realized. In short, this approach best addresses the divergence between resource selection standards in Texas and New Mexico but comes at a greater cost to New Mexico.

RECOMMENDED PORTFOLIO

EPE presents as its recommended resource plan Option 2, the Least Cost plus REA resource portfolio. The resulting incremental portfolio additions for the total system are shown in Table 2. Table 6 shows the New Mexico incremental resource portfolio additions.

Table 6. Incremental Resources Portfolio Additions for New Mexico

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*94*	*1*	*50*	*192*	*101*	*352*
Gas_CT	-	-	-	-	-	-
Gas 5-Yr Extension	*15*	*63*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	-	-	*59*	*303*	*225*	*199*
Wind	*122*	-	-	-	*28*	-

EPE will pursue this portfolio by conducting separate jurisdictional Requests for Proposals ("RFP") specific to New Mexico and Texas. This will allow EPE to pursue respective jurisdictional specific RPS requirements to meet demand. The separate RFP solicitations and resulting regulatory approval filings will also provide New Mexico with autonomy in making resource decisions. While the resources will be pursued via separate RFPs, the total system resource portfolio's capacity will be pooled and will be optimally dispatched at a system wide level to offer the cost benefits shown by the Least Cost plus REA analysis.

Under this IRP, REA compliance will be measured annually to ensure New Mexico assigned renewable resources and carbon free resources meet or exceed New Mexico's REA targets including the 100 percent carbon free requirement. For example, there may be hours of the year that gas generation may serve New Mexico load; however, the total New Mexico assigned carbon free resources' output will equal or exceed the total annual New Mexico retail sales to ensure compliance with the 100 percent carbon free requirement.

The final EPE System and New Mexico L&Rs are presented in Figure 5a-5b and Figure 6a-6b respectively. Given that the RESOLVE analysis looks at six discrete build years, the L&Rs

distribute some of the resource additions to address preceding years due to retirements and associated deficiencies.

LOADS AND RESOURCES

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Figure 5a. EPE System Final L&R

System	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	244	202	202	202	202	202	202	202	202	202
1.2 NEWMAN	654	801	801	801	801	801	733	733	733	733
1.3 COPPER	65	65	65	65	65	65	65	65	65	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE	585	585	585	585	585	585	585	585	585	585
1.6 RENEWABLES[2]	4	4	4	3	3	3	3	3	3	3
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE[4]	52	52	52	52	52	55	55	55	55	62
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**1943**	**2048**	**2047**	**2046**	**2046**	**2050**	**1982**	**1982**	**1982**	**1924**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	58	53	52	45	44	44	44	44	38	38
2.2 NEW RENEWABLE PURCHASE[7]	11	85	83	72	71	71	70	70	62	61
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	54	49	49	42	42	41	41	41	36	36
2.4 NEW BATTERY PURCHASE[9]	50	50	50	50	50	50	50	50	46	46
2.5 EDDY TIE PURCHASE[10]	35	35	35	35	35	35	35	35	35	35
2.6 MARKET RESOURCE PURCHASE[11]	230	90	110	0	0	0	80	125	0	20
2.0 TOTAL RESOURCE PURCHASES	**438**	**362**	**379**	**243**	**242**	**241**	**320**	**364**	**217**	**236**
3.0 FUTURE RESOURCES[12]										
3.1 RENEWABLE / SOLAR	0	0	0	68	67	67	66	66	152	152
3.2 RENEWABLE / WIND	0	0	0	52	52	53	53	53	54	54
3.3 BATTERY STORAGE	0	0	0	126	126	126	126	126	378	378
3.4 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**246**	**246**	**246**	**246**	**245**	**584**	**584**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2381**	**2409**	**2426**	**2535**	**2534**	**2537**	**2548**	**2592**	**2783**	**2743**
5.0 SYSTEM DEMAND[13]										
5.1 NATIVE SYSTEM DEMAND	**2188**	**2225**	**2252**	**2293**	**2331**	**2372**	**2408**	**2459**	**2506**	**2553**
5.2 DISTRIBUTED GENERATION	-14	-18	-23	-25	-30	-34	-39	-43	-48	-46
5.3 ENERGY EFFICIENCY	-15	-23	-31	-38	-46	-54	-62	-69	-77	-85
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2158**	**2184**	**2198**	**2229**	**2255**	**2284**	**2308**	**2347**	**2381**	**2422**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**222**	**226**	**228**	**306**	**279**	**252**	**240**	**245**	**402**	**322**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**219**	**222**	**224**	**228**	**231**	**234**	**237**	**241**	**313**	**318**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**3**	**3**	**4**	**78**	**48**	**18**	**3**	**3**	**88**	**3**

1. Generation unit retirements are consistent with the 2021 IRP. Rio Grande 6 is classified as inactive reserve.
2. Existing EPE owned solar renewables (27% - 54% ELCC)
3. Emerging technologies may include customer or other distributed resources as well as additional community solar. None were used for the 2021 IRP.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2021 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs (27% - 54% ELCC)
7. New renewable solar PPAs (27% - 54% ELCC)
8. New solar and battery storage PPAs (27% - 54% ELCC)
9. 50 MW New Battery Purchase reflects the 50 MW battery that is coupled with the 100 MW solar PPA. (71% - 100% ELCC)
10. 35MW reliability purchase through the Eddy tie.
11. Denotes market purchase either spot market or short-term purchased power.
Amounts greater than 645 MW-PV output will need to come into EPE via exchange
(Freeport), through the acquisition of additional transmission or on a non-firm path.
Also, availability of such power is not guaranteed.
12. Future Resources from 2025 forward are to address both NM RPS and system capacity needs.
13. System demand is based on the 2021 Long-Term Forecast dated April 2021.
14. Effective Load Carrying Capability ("ELCC") is expressed as a percentage of the generators nameplate rating which is the contribution to reliably serve load and is listed here for the peak hour.

Figure 5b. EPE System Final L&R (continued)

System	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	202	202	74	74	74	74	74	74	74	74
1.2 NEWMAN	452	452	452	452	452	452	452	452	452	452
1.3 COPPER	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE	585	585	585	585	585	585	585	585	585	585
1.6 RENEWABLES[2]	2	2	2	2	2	2	2	2	2	2
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE[4]	62	62	62	69	69	69	69	69	78	78
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**1642**	**1642**	**1514**	**1521**	**1521**	**1521**	**1520**	**1520**	**1529**	**1529**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	24	24	24	10	10	9	2	2	2	2
2.2 NEW RENEWABLE PURCHASE[7]	48	48	48	48	47	47	42	42	42	42
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	28	28	28	28	28	28	25	25	25	25
2.4 NEW BATTERY PURCHASE[9]	36	36	36	36	36	36	35	35	35	35
2.5 EDDY TIE PURCHASE[10]	35	35	35	35	35	35	35	35	35	35
2.6 MARKET RESOURCE PURCHASE[11]	10	60	0	20	65	130	40	105	25	90
2.0 TOTAL RESOURCE PURCHASES	**182**	**232**	**171**	**177**	**221**	**284**	**180**	**245**	**165**	**229**
3.0 FUTURE RESOURCES[12]										
3.1 RENEWABLE / SOLAR	249	247	322	321	319	318	335	333	365	363
3.2 RENEWABLE / WIND	55	55	55	55	55	55	59	59	62	62
3.3 BATTERY STORAGE	567	567	729	729	729	729	796	796	847	847
3.4 GAS GENERATION	82	82	130	130	130	130	205	205	255	255
3.0 TOTAL RESOURCE PURCHASES	**952**	**951**	**1237**	**1235**	**1233**	**1232**	**1395**	**1393**	**1529**	**1527**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2776**	**2825**	**2921**	**2932**	**2975**	**3037**	**3096**	**3159**	**3223**	**3286**
5.0 SYSTEM DEMAND[13]										
5.1 NATIVE SYSTEM DEMAND	**2593**	**2650**	**2702**	**2756**	**2804**	**2869**	**2931**	**2996**	**3060**	**3125**
5.2 DISTRIBUTED GENERATION	-51	-55	-59	-50	-53	-56	-60	-63	-60	-63
5.3 ENERGY EFFICIENCY	-92	-100	-108	-115	-123	-131	-138	-146	-154	-162
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2450**	**2495**	**2535**	**2591**	**2628**	**2682**	**2733**	**2787**	**2847**	**2901**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**326**	**330**	**386**	**342**	**347**	**354**	**363**	**372**	**376**	**385**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**323**	**329**	**335**	**341**	**346**	**353**	**360**	**368**	**375**	**382**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**4**	**1**	**51**	**1**	**2**	**1**	**3**	**4**	**2**	**3**

Figure 6a. EPE New Mexico Final L&R

New Mexico	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	49	40	40	40	40	40	40	40	40	40
1.2 NEWMAN	130	118	118	118	118	118	104	104	104	104
1.3 COPPER	13	13	13	13	13	13	13	13	13	0
1.4 MONTANA	66	66	66	66	66	66	66	66	66	66
1.5 PALO VERDE	78	78	78	78	78	78	78	78	78	78
1.6 RENEWABLES	3	2	2	2	2	2	2	2	2	2
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE	10	10	10	10	10	11	11	11	11	12
1.10 LINE LOSSES FROM OTHERS	2	2	2	2	2	2	2	2	2	2
1.0 TOTAL GENERATION RESOURCES	**350**	**329**	**329**	**329**	**329**	**329**	**316**	**316**	**316**	**304**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE	31	28	28	24	24	23	23	23	20	20
2.2 NEW RENEWABLE PURCHASE	11	45	44	38	38	37	37	37	33	32
2.3 NEW RENEWABLE/ BATTERY PURCHASE	11	10	10	8	8	8	8	8	7	7
2.4 NEW BATTERY PURCHASE	10	10	10	10	10	10	10	10	9	9
2.5 EDDY TIE PURCHASE	7	7	7	7	7	7	7	7	7	7
2.6 MARKET RESOURCE PURCHASE	55	55	60	0	0	0	0	0	0	0
2.0 TOTAL RESOURCE PURCHASES	**124**	**155**	**158**	**87**	**86**	**86**	**85**	**85**	**76**	**76**
3.0 FUTURE RESOURCES										
3.1 RENEWABLE / SOLAR	0	0	0	0	0	0	0	0	22	22
3.2 RENEWABLE / WIND	0	0	0	31	31	32	32	32	33	33
3.3 BATTERY STORAGE	0	0	0	95	95	95	95	95	134	134
3.4 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**126**	**126**	**126**	**126**	**126**	**188**	**188**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**475**	**484**	**487**	**541**	**541**	**542**	**528**	**527**	**580**	**568**
5.0 SYSTEM DEMAND										
5.1 NATIVE SYSTEM DEMAND	**437**	**444**	**450**	**458**	**465**	**474**	**481**	**491**	**500**	**510**
5.2 DISTRIBUTED GENERATION	-3	-5	-6	-6	-7	-8	-10	-11	-12	-11
5.3 ENERGY EFFICIENCY	-3	-5	-6	-8	-9	-11	-12	-14	-15	-17
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**430**	**435**	**438**	**444**	**449**	**454**	**459**	**466**	**473**	**481**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**44**	**49**	**50**	**97**	**92**	**87**	**69**	**61**	**107**	**87**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**44**	**44**	**45**	**45**	**46**	**47**	**47**	**48**	**63**	**64**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**1**	**4**	**5**	**52**	**46**	**40**	**21**	**13**	**44**	**23**

Figure 6b. EPE New Mexico Final L&R (continued)

New Mexico	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	40	40	15	15	15	15	15	15	15	15
1.2 NEWMAN	48	48	48	48	48	48	48	48	48	48
1.3 COPPER	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	66	66	66	66	66	66	66	66	66	66
1.5 PALO VERDE	78	78	78	78	78	78	78	78	78	78
1.6 RENEWABLES	1	1	1	1	1	1	1	1	1	1
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE	12	12	12	14	14	14	14	14	16	16
1.10 LINE LOSSES FROM OTHERS	2	2	2	2	2	2	2	2	2	2
1.0 TOTAL GENERATION RESOURCES	**248**	**248**	**222**	**223**	**223**	**223**	**223**	**223**	**225**	**225**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE	10	10	10	7	7	6	0	0	0	0
2.2 NEW RENEWABLE PURCHASE	26	25	25	25	25	25	22	22	22	22
2.3 NEW RENEWABLE/ BATTERY PURCHASE	6	6	6	6	6	6	5	5	5	5
2.4 NEW BATTERY PURCHASE	7	7	7	7	7	7	7	7	7	7
2.5 EDDY TIE PURCHASE	7	7	7	7	7	7	7	7	7	7
2.6 MARKET RESOURCE PURCHASE	0	0	0	0	0	0	0	0	0	0
2.0 TOTAL RESOURCE PURCHASES	**56**	**55**	**55**	**52**	**52**	**50**	**41**	**41**	**41**	**41**
3.0 FUTURE RESOURCES										
3.1 RENEWABLE / SOLAR	74	74	107	106	106	105	131	131	154	154
3.2 RENEWABLE / WIND	33	33	33	33	33	33	37	37	40	40
3.3 BATTERY STORAGE	190	190	241	241	241	241	281	281	310	310
3.4 GAS GENERATION	0	0	0	0	0	0	0	0	0	0
3.0 TOTAL RESOURCE PURCHASES	**297**	**297**	**381**	**380**	**380**	**379**	**450**	**449**	**505**	**504**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**600**	**600**	**658**	**656**	**655**	**653**	**715**	**714**	**771**	**770**
5.0 SYSTEM DEMAND										
5.1 NATIVE SYSTEM DEMAND	**518**	**529**	**539**	**550**	**560**	**573**	**585**	**598**	**611**	**624**
5.2 DISTRIBUTED GENERATION	-12	-14	-15	-12	-13	-14	-15	-16	-15	-16
5.3 ENERGY EFFICIENCY	-18	-20	-21	-23	-25	-26	-28	-29	-31	-32
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**487**	**496**	**503**	**515**	**522**	**533**	**543**	**553**	**565**	**576**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**114**	**104**	**155**	**141**	**133**	**120**	**172**	**160**	**206**	**194**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**64**	**66**	**67**	**68**	**69**	**71**	**72**	**73**	**75**	**76**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**49**	**39**	**88**	**73**	**64**	**50**	**100**	**87**	**131**	**118**

A. 2021 IRP Four-Year Action Plan

EPE's four-year action plan includes the following steps:

- EPE will continue moving forward with the selected resources previously approved by the Commission in Case Nos. 19-00099-UT and 19-00348-UT (Hecate I and II and Buena Vista I and II). These resources have an anticipated Commercial Operation Date (“COD”) of 2022 and 2023.
- EPE will complete the regulatory approval process for EPE’s 2021 Annual Renewable Energy Plan filed May 5, 2021, and file subsequent annual reports and plans in 2022, 2023, 2024, and 2025 pursuant to 17.9.572 NMAC and the REA.
- EPE will complete the regulatory approval process for the 2022-2024 Energy Efficiency and Load Management Plan filed July 16, 2021 and will file a subsequent 3-year plan pursuant to 17.7.2 NMAC and the Efficient Use of Energy Act (“EUEA”).
- EPE will complete the New Mexico RFP in 2021 to address current capacity needs and RPS resource needs to meet the REA’s 2025 target of 40 percent.
- EPE will conduct a Demand Side Management potential study.
- EPE will continue to consider voluntary customer programs for renewable energy.
- EPE will file for abandonment of units that are past their useful lives.

CLEAN ENERGY GOALS

EPE has recently adopted clean energy goals for its total system resource mix. Based on the IRP’s comprehensive analyses, EPE believes these goals are attainable in way that balances reliable electric service, customer affordability and environmental impacts.

EPE intends to serve our community’s power needs with at least 80% carbon-free energy by 2035 with a continued pursuit of 100% decarbonization of our generation portfolio by 2045[2] as expected technological advancements in performance and costs continue to evolve. EPE expects to meet these goals through the continued deployment of solar and other renewable resources coupled with storage over the coming years, along with our existing carbon-free nuclear generation. EPE is optimistic that the ongoing technology evolution will ultimately lead to even deeper decarbonization of its generation portfolio, beyond the 80% clean energy milestone. EPE will continue to evaluate alternative energy technologies, fuels, and efficiency strategies to identify progressively cleaner ways to serve the region and EPE’s customers reliably and affordably. EPE is encouraged by federal and state clean energy initiatives and supportive of proposals that will accelerate technology development to make even more ambitious targets economically viable for the region.

[2] Scope 1 Emissions

II. IRP PLANNING OVERVIEW

The Plan was developed pursuant to the requirements of the IRP Rule. The Planning Process took into consideration the following key objectives:

- identify the most cost-effective portfolio of resources that best meets customer needs for the next twenty years,

- consider various resource options, including supply-side and demand-side options, while taking into consideration statutory requirements, environmental sustainability, reliability, risk; and,

- partner up with customers via the Public Process to provide information to and receive inputs and recommendations throughout the Planning Process.

The Planning Process can be described as the method to develop the most cost-effective integrated resource portfolio to supply safe, reliable, and environmentally conscientious energy to meet the needs of EPE's customers for the next twenty years. The purpose of the IRP Rule is:

> *"…to identify the most cost-effective portfolio of resources to supply the energy needs of customers. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts."*

Section 10 of the EUEA calls for the periodic filing of an IRP with the Commission. The IRP Rule requires that the following information be included in an electric utility's IRP:

- a description of existing electric supply-side and demand-side resources,
- a current load forecast as described in this Rule,
- a load and resources table,
- the identification of resource options,
- a description of the resource and fuel diversity,
- the identification of critical facilities susceptible to supply-source or other failures,
- the determination of the most cost-effective resource portfolio and alternative portfolios,
- a description of the Public Process,
- an action plan, and
- other information that the utility finds may aid the Commission in reviewing the utility's planning processes.

Statutory energy efficiency and load management goals and renewable energy standards are incorporated into the Planning Process. EPE evaluated renewable energy resources, energy efficiency, and demand side management resources to meet the REA and EUEA requirements through the Planning Process. For example, the EUEA establishes energy efficiency and load management programs that are approved by the Commission. EPE’s statutory goal is five percent of the 2020 retail sales by 2025. In addition, the REA establishes a renewable portfolio standard (“RPS”) for EPE's New Mexico jurisdiction, requiring a number of renewable resources based on a percentage of EPE's annual New Mexico retail energy sales.

EPE is committing a significant amount of time and resources to the Public Process. The Public Process allows EPE to receive valuable feedback and insight into what different members of the community value in EPE's Planning Process. Although, the Public Process is required by the IRP Rule, EPE welcomes and supports the integral role it plays in the IRP.

While the IRP requirement is a three-year cycle, EPE continually evaluates its’ Plan for resource adequacy and reliability. The ongoing Planning Process can be summarized in the following steps:

- determine a baseline for future capacity needs utilizing the latest load forecast that incorporates data for distributed generation (“DG”), energy efficiency and load management (“EE/LM”), and electric vehicle charging (“EV”), and comparing that to the most current information for existing supply-side resources and their expected retirement dates;
- identify possible demand-side and supply-side resources that may be utilized to serve load safely and reliably if a capacity need is determined. This requires the consideration of advancements in technology and resource options including the complexities of resource characteristics and costs. The incorporation of data from the prior RFP results, along with publicly available information, is used to form resource assumptions
- analyze resource options to ensure reliability, adequacy, statutory compliance, and appropriate integration into EPE's system to select the most cost-effective portfolio of resources to best meet customer needs, safely and reliably (the “expansion portfolio”),
- incorporate applicable forecast data, existing resource information and expansion portfolio into the L&R, and
- update annually with latest forecast and resource data.

EPE follows the process as summarized above during its annual and continuous resource planning in the usual course of business. However, during years where the IRP Planning Process is occurring, additional key steps occur

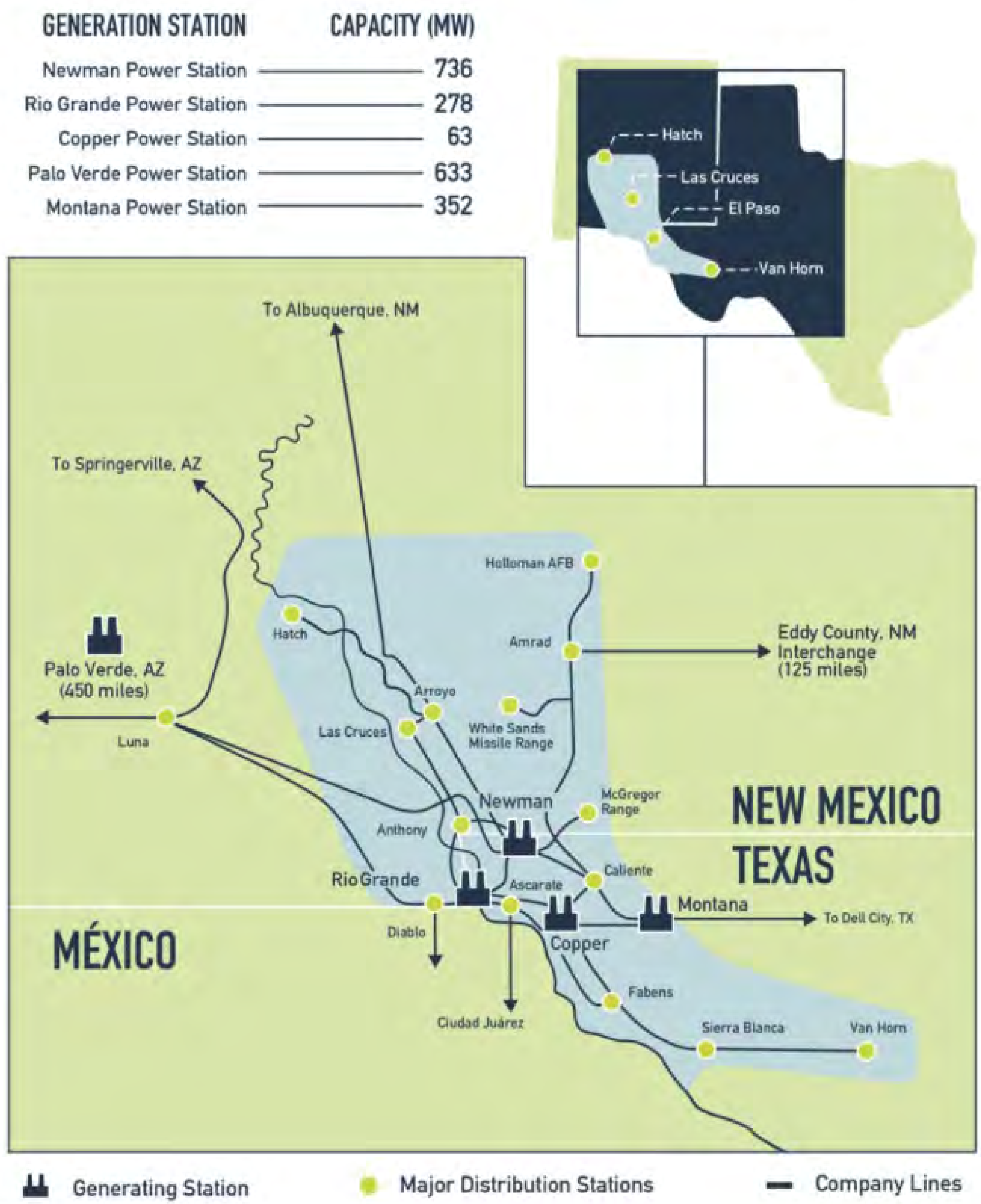
- performance of sensitivity analyses of various factors, such as load forecast, fuel cost, carbon tax considerations at various rates, DG growth, EV growth, along with feasible supply side and demand side resource options as suggested by the Public Participants, and

- production of the four-year action plan.

A. Service Territory/Company Overview

EPE is a public utility engaged in the generation, transmission, and distribution of electricity in an area of approximately 10,000 square miles in west Texas, and southern New Mexico (from Van Horn, Texas to Hatch, New Mexico). The Company serves approximately 437,000 residential, commercial, industrial, public authority and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas, and Las Cruces, New Mexico. In addition, the Company's wholesale energy sales include those for resale to other electric utilities and to power marketers. Principal industrial, public authority and other large retail customers of the Company include United States military installations, such as Fort Bliss in Texas, as well as White Sands Missile Range ("White Sands") and Holloman Air Force Base ("HAFB"), both in New Mexico. EPE also serves an oil refinery, several medical centers, two major universities and a steel production facility. Figure 7 shows a geographical representation of EPE's total service territory.

Figure 7 – EPE Service Territory



B. Summary of the 2018 IRP Action Plan and Status

EPE has completed all required items set forth in its 2018 IRP four-year action plan. In summary, EPE:

- filed for regulatory approval with the NMPRC for resources selected from the Company's 2017 All Source RFP for Electric Power Supply and Load Management Resources;
- filed its 2018, 2019-2020, and 2021 Annual Renewable Energy Plan pursuant to 17.9.572 NMAC and the REA;
- filed its 2019-2021 Energy Efficiency and Load Management Plan in 2018 pursuant to 17.7.2 NMAC and the EUEA and its 2022-2024 Plan on July 16, 2021.
- Initiated an RFP to be issued in 2021 to address resource needs identified in 2024;
- evaluated the Demand Response Pilot Program results at the conclusion of the program; and,
- proposed a voluntary New Mexico Community Solar program and proposed and received approval for a New Mexico State University solar generation project.

III. DESCRIPTION OF EXISTING RESOURCES

A. Supply Side Resources

EPE's existing supply side resources provide a foundation for integrated resource planning. EPE utilizes its current supply side resources to satisfy the bulk of its customers' electrical demands with power generated from company-owned generating facilities fueled by solar, natural gas, and uranium. EPE also purchases renewable energy through various long-term Purchased Power Agreements ("PPAs") and Qualifying Facilities (“QF”). In addition, EPE purchases varying amounts of firm and non-firm energy through the wholesale markets to meet the needs of its customers. Also, EPE is currently in the process of joining the Western Energy Imbalance Market which offers a real-time energy market that allows members to find low-cost energy across a wide geographic area to serve real-time customer electricity demand. These resources, in combination with future low-cost efficient options, will create a portfolio that results in the most cost-effective plan for EPE customers, considering reliability and risk.

1. Generating facilities and expected retirement dates

EPE owns and operates a fleet of local and remote generating units. The Rio Grande Generating Station ("Rio Grande"), Newman Generating Station ("Newman"), Montana Power Station ("MPS"), and Copper Generating Station ("Copper") are all located in EPE's service territory, within or near the City of El Paso, Texas. These generating stations are considered EPE's local generation. In addition, EPE owns six small solar PV systems located at (1) Rio Grande in Sunland Park, New Mexico, (2) Newman in northeast El Paso, (3) Wrangler Substation in east El Paso, (4) the El Paso Community College – Valle Verde Campus in El Paso's Lower Valley, (5) EPE's Van Horn customer service center, and (6) the rooftop of EPE's headquarters in downtown El Paso.

EPE expanded its renewable portfolio with the addition of its Texas Community Solar Facility and the Holloman Solar Facility in 2017 and 2018, respectively. The Texas Community Solar Facility is a 3 MW Solar PV system located on approximately 21 acres near the MPS, whose generation is dedicated to EPE’s Texas Community Solar program which allows customers to voluntarily subscribe to utility-scale single-axis tracking PV based on their current usage. It allows customers to participate in supporting renewable energy generation without physically having to locate solar panels where they reside. It became commercially operational on May 31, 2017 and, to date, is fully subscribed. On March 20, 2018, EPE filed, with the Public Utility Commission of Texas ("PUCT"), to expand the Texas Community Solar program by 2 MW, utilizing 2 MW of solar generation from the 10 MW Newman Solar Facility. Therefore, the Texas Community Solar program consists of a total of 5 MW, i.e., 3 MW of EPE-owned generation and 2 MW from the Newman Solar Facility which is under a PPA.

The Holloman Solar Facility is a 5 MW EPE-owned solar resource dedicated to serve HAFB. It became commercially operational on October 18, 2018.

PVNGS, located near Phoenix, Arizona, is considered EPE's remote generation. EPE owns 15.8 percent of the PVNGS' Units 1, 2, and 3.

EPE's existing generating stations with fuel types, in-service dates, and currently planned retirement dates are listed in Table 7. Table 7 includes Rio Grande Unit 6 as required in the Final Order of Case No. 17-00317-UT. It is also important to note that the majority of EPE's generating facilities listed in Table 7 have been in service for a significant number of years. This is an important consideration for integrated resource planning because the aging units being considered for retirement, within the Planning Horizon, will affect EPE's capacity needs. Additional output data required by the IRP Rule, such as capacity factor, fuel costs, heat rate, and total operation and maintenance ("O&M") costs, is provided hereto in Attachment C-2.

Table 7. EPE-owned Existing Generation Stations and Fuel Types

Generating Station	Location	Nominal Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	In-Service Date	Planned Retirement Date	Unit Age at Planned Retirement
PVNGS Unit 1 Unit 2 Unit 3	Phoenix, AZ	622	Uranium	N/A	February 1986 September 1986 January 1988	June 2045 April 2046 November 2047	59 60 59
Montana Unit 1 Unit 2 Unit 3 Unit 4	El Paso, TX	352	Natural Gas	Fuel Oil	March 2015 March 2015 May 2016 September 2016	December 2060 December 2060 December 2061 December 2061	45 45 45 45
Rio Grande Unit 6 (1) Unit 7 Unit 8 Unit 9	Sunland Park, NM	323	Natural Gas	N/A	June 1957 June 1958 July 1972 May 2013	December 2021 December 2022 December 2033 December 2058	64 64 61 45
Newman Unit 1 Unit 2 Unit 3 Unit 4 Unit 5 – CTs Unit 5 – HRSG	El Paso, TX	729	Natural Gas	N/A	May 1960 June 1963 March 1966 June 1975 May 2009 April 2011	December 2022 December 2022 December 2026 December 2026 December 2061 December 2061	62 59 60 51 52 50
Copper Unit 1	El Paso, TX	63	Natural Gas	N/A	July 1980	December 2030	50
EPE-owned Solar Texas Community Solar Holloman Solar Small Solar Systems	EPE Service Territory	3 5 < 1	N/A	N/A	May 2017 Oct 2018 2009 – 2011	May 2047 October 2048 2029 – 2032	Various

(1) Rio Grande Unit 6 is subject to a pending abandonment proceeding in Case No. 20-00194-UT.

2. Purchased Power Agreements

In addition to relying on its own generating facilities, EPE also relies on resources acquired from wholesale suppliers or other sources. The current long-term PPAs that EPE has in place to serve its customers are listed in Table 8.

Table 8. EPE-existing Renewable Generation Resources

Purchase Power Agreement	Location	Nominal Capacity (MW)	In-Service Date	Term
NRG Solar Roadrunner LLC ("NRG")	Santa Teresa, NM	20	August 2011	20 years
Hatch Solar Energy Center I, LLC ("Hatch")	Hatch, NM	5	July 2011	25 years
SunE EPE1, LLC ("SunEdison")	Chaparral, NM	10	June 2012	25 years
SunE EPE2, LLC ("SunEdison")	Las Cruces, NM	12	May 2012	25 years
Macho Springs Solar, LLC ("Macho Springs")	Luna County, NM	50	May 2014	20 years
Newman Solar LLC ("Newman")	El Paso, TX	10	December 2014	30 years
Buena Vista Energy Center, LLC ("Buena Vista 1")	Otero County, NM	100	May 2022	20 years
Buena Vista Energy Center II, LLC ("Buena Vista 2")	Otero County, NM	20	May 2022	20 years
Hecate Energy Santa Teresa, LLC ("Hecate 1")	Santa Teresa, NM	100	December 2022	20 years
Hecate Energy Santa Teresa 2, LLC ("Hecate 2")	Santa Teresa, NM	50	December 2022	20 years

Additionally, interconnected to EPE's system is a biogas energy QF, the Camino Real Landfill Gas to Energy Facility or Four Peaks (3.2 MW) located in Sunland Park, New Mexico (at the Camino Real Landfill).[3] Furthermore, EPE offers net metering and REC programs for customer-owned solar PV and wind generation. The RECs obtained from New Mexico renewable resources are used to meet EPE's New Mexico RPS requirements.

On November 18, 2019, the Company filed for NMPRC approval of the PPAs selected from the Company's 2017 All Source RFP for Electric Power Supply and Load Management Resources. The two, NMPRC-approved PPAs include: (i) a 100 MW solar plant to be constructed in Santa Teresa, New Mexico; and (ii) a 100 MW solar plant combined with a 50 MW battery energy storage to be constructed in Otero County, New Mexico. On March 31, 2020 the Company filed for regulatory approval with the NMPRC for two additional solar resources to meet the New Mexico RPS.

[3] The $30/MWh renewable energy credit ("REC") premium for this facility approved by the Commission in Case No. 18-00099-UT, is subject to a Commission Stay Order issued in that docket, while pending a City of Las Cruces appeal of the Commission Final Order in that case to the New Mexico Supreme Court.

These two additional renewable resources were approved by the NMPRC on December 2, 2020 and include: (iii) a 50 MW solar plant to be constructed in Santa Teresa, New Mexico and (iv) a 20 MW solar plant to be constructed in Otero County, New Mexico.

In combination with existing and upcoming EPE-owned resources, these PPAs provide diverse capacity to serve load and give EPE and its customers a robust starting point when analyzing the most cost-effective IRP. Additionally, EPE utilizes short-term market purchases to mitigate the need for new resource additions and to allow for economical resource selections.

3. Approved Utility-owned Generation not In-service

Newman Unit 6 ("NM6"), also known as Newman GT5, is a 1x0 Mitsubishi M501GAC simple-cycle combustion turbine expected to provide a total net summer capacity of approximately 228MW. NM6 was selected as a result of EPE's 2017 All Source RFP. The Commission denied EPE's Certificate of Convenience and Necessity ("CCN") Application for NM6 by Final Order issued December 16, 2020. However, the PUCT approved a CCN for NM6 on October 16, 2020. Therefore, EPE is pursuing required permitting for NM6 and it is anticipated to be commercially operational May 1, 2023 as a Texas resource.

B. Environmental Impacts of Existing Supply-Side Resources

EPE has a firm commitment to environmental stewardship and consistently evaluates potential impacts to environmental resources during resource planning processes. In general, the environmental considerations for siting renewable generation facilities, conventional generation facilities, and transmission and distribution facilities are similar, though the resources impacted vary greatly based on the type, location, geographic setting, and expanse of any given project. The degree of environmental regulatory guidance and review will also vary based on the location and other project specific parameters; but, in all cases environmental resources are considered.

EPE is subject to extensive laws, regulations and permit requirements with respect to air and greenhouse gas ("GHG") emissions, water discharges, soil and water quality, waste management and disposal, natural resources and other environmental matters by federal, state, regional, tribal, and local authorities.

1. Air Emissions

Emission rates for each of EPE's generation facilities required by 17.7.3.9(C)(13)(b) NMAC are listed in Table 9. The Clean Air Act ("CAA"), associated regulations and comparable state and local laws and regulations that relate to air emissions impose, among other obligations, limitations on pollutants generated during the operations of the Company's facilities and assets, including sulfur dioxide ("SO2"), particulate matter ("PM"), nitrogen oxides ("NOx") and mercury.

Table 9. Environmental Impacts of Existing Supply Side Resources

2020 Data: Based on Rolling Average							
Unit	NOx [3]	CO [3]	PM	SO_2 [4]	Hg[1]	CO_2 [5]	Water Consumption[6]
	(lbs/kWh)						(gal/kWh-site)
Montana 1	0.00010	0.00003	0.00006	0.00001	*	1.10	0.18
Montana 2	0.00011	0.00005	0.00006	0.00001	*	1.08	
Montana 3	0.00011	0.00003	0.00007	0.00001	*	1.15	
Montana 4	0.00011	0.00005	0.00006	0.00001	*	1.08	
Rio Grande 6	0.00000	0.00000	0.00000	0.00000	*	0.00	0.64
Rio Grande 7	0.00148	0.00013	0.00001	0.00000	*	1.43	
Rio Grande 8	0.00224	0.00015	0.00008	0.00000	*	1.28	
Rio Grande 9	0.00010	0.00011	0.00001	0.00000	*	1.16	
Newman 1	0.00250	0.00021	0.00001	0.00001	*	1.42	0.61
Newman 2	0.00208	0.00011	0.00001	0.00001	*	1.38	
Newman 3	0.00155	0.00005	0.00001	0.00001	*	1.29	
Newman 4 [2]	0.00163	0.00044	0.00001	0.00001	*	1.19	
Newman 5	0.00007	0.00006	0.00007	0.000005	*	0.97	
Copper 1	0.00576	0.00262	0.00013	0.00001	*	2.24	0.09
Palo Verde 1	0	0	0	0	0	0	0.73
Palo Verde 2	0	0	0	0	0	0	
Palo Verde 3	0	0	0	0	0	0	

[1] No oil burned in 2020; therefore, no Hg emissions were created

[2] Newman GT-1 and GT-2

[3] Rio Grande, Newman, Montana, and Copper NOx and CO emission data from continuous emissions monitoring system

[4] Rio Grande, Newman, Montana, and Copper SO_2 emission data calculated from natural gas sulfur content

[5] Rio Grande, Newman, and Montana CO_2 emission data calculated as per 40 CFR 75 Appendix G, Equation G-4; Copper as per 40 CFR 98 Subpart C

[6] EPE's water consumption at Palo Verde is estimated as 15.8 percent (percentage of ownership by EPE) of the total from Units 1, 2, and 3

Impacts to air quality are evaluated against CAA regulations to determine suitability of a proposed technology and feasibility of permitting. During the permitting phase of a project with potential emissions, ranging from the purchase of an emergency generator to installation of a new conventional generation unit, an emissions review is conducted. During this review, potential emission constituents and rates are evaluated to determine potential impacts and what, if any, emission thresholds are triggered. Technologies and pollution control methods are selected to meet or exceed the requirements set forth by State and Federal regulations, including the National Ambient Air Quality Standards ("NAAQS"). Most of EPE's air emissions result from the combustion of fossil fuels. Consequently, conventional generation projects undergo the most rigorous air quality assessments. However, air quality is considered in the full scope of projects including fugitive dust during construction and large area land clearing, as well as operations and maintenance traffic volume along transmission rights-of-way.

Under the CAA, the Environmental Protection Agency ("EPA") sets NAAQS for six criteria pollutants considered harmful to public health and the environment, including PM, NOx, carbon monoxide ("CO"), ozone and SO2. NAAQS must be reviewed by the EPA at five-year intervals, and if necessary, revised. On October 1, 2015, the EPA released a final rule tightening the primary and secondary 8-hour NAAQS for ground-level ozone from its 2008 standard levels of 75 parts per billion (ppb) to 70 ppb. Ozone is the main component of smog. While not directly emitted into the air, it forms from its precursors, NOx, and VOCs, in combination with sunlight. The EPA recently designated one of the areas in which we operate as nonattainment. Specifically, in December 2017, EPA proposed to designate southern Doña Ana County, New Mexico, as a nonattainment area. In June of 2018 the EPA provided public notice of this designation and later officially designated the area as nonattainment. In July 2020 the U.S. Court of Appeals for the D.C. Circuit remanded the attainment designation assigned to El Paso County back to the EPA for further consideration and explanation. On May 25, 2021, the EPA sent a 120-day notification letter to the State of Texas stating they intend to modify the El Paso ozone designation to nonattainment. States that contained any areas designated as nonattainment were required to complete development of State Implementation Plans in the 2020-2021 timeframe for marginal and moderate designations.

Nonattainment areas deemed marginal are expected to have until August 2021 to meet the primary (health) standard, while attainment in moderate areas needs to be obtained by August 2024. The Company continues to evaluate the impact these final and proposed NAAQS could have on operations.

2. Climate Change

There has been a wide-ranging policy debate, at the local, state, national, and international levels, regarding GHGs and possible means for their regulation. Efforts continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, and sets GHG emission reduction goals every five years, beginning in 2020. In August 2017, the United States formally documented to the United Nations its intent to withdraw from the Paris Agreement and although the official withdrawal was finalized in November 2020, the US officially rejoined in February 2021 along with pledging to reduce GHG emissions by 50 percent from 2005 levels by 2030. The federal government signaled a “whole-of-government” approach expecting the private sector to partner in transforming many business sectors, amongst them the power industry.

The federal government has either considered, proposed and/or finalized legislation or regulations limiting GHG emissions, including carbon dioxide ("CO_2"). In particular, the U.S. Congress has considered legislation to restrict or regulate GHG emissions. In October 2015, the EPA published a rule establishing guidelines for states to regulate CO_2 emissions from existing power plants, known as the Clean Power Plan ("CPP"). Legal challenges to the CPP led to the Supreme Court halting enforcement in 2016 and a failed attempt at replacing it with the Affordable Clean Energy (ACE) rule in 2017. Although it was ruled that the ACE violated the CAA in January 2021, the CPP was not reinstated leaving the door open to a new rule being proposed. The current Biden administration is pursuing climate initiatives which may result in funding, incentives or new requirements.

While it is not possible to predict the precise outcome of any pending, proposed or future GHG legislation by Congress, state or multi-state regions or any GHG regulations adopted by the EPA or state agencies, a significant portion of EPE's generation assets are nuclear or gas fired. As a result, the Company's GHG emissions are low relative to electric power companies who rely more on coal-fired generation, and largely align with proposed and/or recently promulgated GHG regulations. In accordance with the CAA 111(b), performance standards for newly constructed electric generating units, Newman 6 will be the first EPE unit to operate with a permitted GHG emission limit. This will aid in achieving EPE’s carbon reduction goals.

Climate change also has potential physical effects relevant to the Company's business. Climate change could affect the Company's service area by causing higher temperatures, less winter precipitation, and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

3. Modeling Carbon and Emissions Cost.

As discussed, the details of future carbon regulations remain in flux; however, EPE anticipates that carbon regulations will ultimately become formalized at the state and/or federal level. The physical consequences of climate change as well as the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both, may impact EPE's operation. As such, EPE models the three Commission ordered sensitivity scenarios with standardized cost (per ton) of CO_2 emissions within each resource portfolio. EPE's modeling includes emission rates specific to each conventional resource type and applicable costs as part of the portfolio analysis.

4. Water Resources

Rate of consumptive water use, required by 17.7.3.9(C)(13)(c) NMAC, is summarized for EPE's existing generation resources in Table 9, and is a primary consideration in comparing generation technologies and evaluating resource portfolios. All the 5 relatively new GE LMS 100 turbines and the planned Newman 6 unit are not steam generating units, and the planned Newman 6 unit specifically will not include a cooling tower in its peripheral equipment, drastically reducing its water consumption rate when compared to older units. Protection and preservation of water resources is primarily governed by the Clean Water Act. Assessment of potential impacts to water resources includes surface water, ground water, wetlands, and other waters of the United States. Water quality standards must be maintained throughout the life of a project from construction through operation. These standards generally are addressed through design factors to prevent storm water pollution and prevent site run-off and discharge. Protection of wetlands and surface waters, including potentially dry arroyos, is best addressed through site selection and any impacts to wetlands or waters of the U.S. are mitigated during appropriate permitting processes.

5. Biological resources

Biological resources include wildlife, avian, vegetation and habitat resources. Regulation of these resources is driven primarily by the Endangered Species and Migratory Bird Treaty Acts. Procedurally, consideration of these resources requires reconnaissance and detailed surveys of potential project areas to evaluate for the presence of native, rare, or critical habitat; or threatened, endangered or other special status species. Protection of biological resources is most challenging for expansive or large land area projects such as solar facilities, transmission corridors or access roads. EPE seeks to minimize impacts to these resources through careful site selection and avoidance as well as through operational techniques such as timing of vegetation clearing when seasonally appropriate to minimize impacts to nesting birds or conducting salvage removal of cacti species or nest relocations when avoidance is not possible.

6. Cultural resources

Cultural resources are abundant and dense within EPE's service territory. Evaluation of potential impacts to cultural resources follows the process outlined by Section 106 of the National Historic Preservation Act and includes a determination of whether cultural resources exist within a project's area of potential effect and whether those resources would be adversely affected. These determinations are made in consultation with the State Historic Preservation Office and any appropriate pueblos and tribes, generally upon completion of intensive surveys and records reviews. Where cultural resources cannot be avoided, mitigation plans are developed prior to any construction. As with biological resources, managing the effects to cultural resources is best achieved through careful site selection and avoidance. However, on expansive projects complete avoidance is not always feasible and mitigation, including site specific data recovery, is completed.

Although no less important, the following resources are also protected or otherwise regulated and considered, though are not as frequently applicable to projects. These include environmental justice, protection of specially designated areas, visual resources, paleontological resources, caves and karst, floodplains, watershed, hazardous and solid wastes, and soils.

EPE evaluates potential impacts to a broad spectrum of environmental resources continuously measuring the sustainability of our businesses practices focusing specifically in the effects on environmental, social, and corporate governance (ESG) factors. The resources and degree of impacts do vary from project to project, but the due consideration of that impact is a consistent factor in EPE's resource planning process.

C. Demand Side Resources

Demand side resources are a reduction to the overall forecasted native system demand. EPE's existing demand side resources are categorized into four primary types as follows:

1. New Mexico Energy Efficiency ("EE") Programs;
2. New Mexico Residential and Commercial Load Management ("LM") Programs;
3. Texas Energy Efficiency Programs; and,
4. Texas Residential and Commercial Load Management Programs.

EPE incorporates demand side resources into its planning process for its New Mexico and Texas jurisdictions. EPE has several programs that promote energy and demand savings for customers. The programs differ by state jurisdiction and are dependent on the goals established by state regulations.

Brief descriptions of the New Mexico EE/LM programs and the Texas EE/LM programs are included below. EPE will continue to consider demand side resource options as part of its IRP as described in Section VI.

1. New Mexico Energy Efficiency Programs

The Commission's March 2019 Final Order in Case No 18-00116-UT approved EPE's 2019-2021 EE/LM Plan. Pursuant to the EE Rule, EPE continues to offer these programs. In EPE's Application for Approval of its proposed 2022-2024 EE/LM Plan filed July 15, 2021, EPE is proposing four new residential programs to help reach additional customers and to be better positioned to meet the increased savings requirements in EUEA.

EPE currently offers five residential EE programs and two commercial EE programs that have been approved by the Commission. Below is a brief description of EPE's current New Mexico EE programs:

Residential

- The Residential Comprehensive Program offers rebates for the installation of attic insulation, duct sealing, air infiltration, evaporative coolers, refrigerated A/C units, solar screens, pool pumps, cool roofs, windows, and smart thermostats.
- The New Mexico EnergySaver (Low Income) Program provides income-qualified customers a variety of EE measures for their homes at no cost, including evaporative cooler replacement, advanced power strips, LED lighting, smart thermostats, attic insulation, duct sealing, air infiltration, water heater pipe and tank insulation, high efficiency showerheads and kitchen and bathroom faucet aerators. Qualification is based on an annual household income at or below 200% of the federal poverty guidelines.

- The LivingWise® Program is an educational program for students. Participating students and teachers are provided with a LivingWise® kit that contains educational materials and energy saving devices that students install in their homes.
- The Residential Lighting Program offers discounts at participating retail locations for customers to replace their existing light bulbs with more energy efficient Light Emitting Diodes ("LED") lighting.
- The ENERGY STAR® New Homes Program provides incentives for homebuilders to construct energy efficient homes that exceed the current building code.

Commercial

- The Commercial Comprehensive Program provides incentives and rebates to commercial customers whose average annual demand is up to and including 100 kW for installing eligible energy efficiency measures such as lighting, HVAC, controls, pool pumps, cool roofs, commercial food service equipment, refrigeration measures, and building envelope measures.
- The SCORE Plus Program provides incentives to large commercial customers with an average demand greater than 100 kW, as well as schools, city, county, and government customers for EE measures including lighting, HVAC, controls, pool pumps, cool roofs, commercial food service equipment, refrigeration measures, building envelope measures, and custom projects.

2. New Mexico Residential and Commercial Load Management Programs

The Commission's March 2019 Final Order in Case No 18-00116-UT approved EPE's Commercial Load Management Program, and the Commission's July 2020 Final Order in Case No 18-00116-UT approved EPE's Residential Load Management Program.

EPE's Residential and Commercial Load Management Programs engage utility customers to reduce their electricity use (load) during peak hours or under certain conditions, which in turn, can substantially reduce demand for electricity during EPE's peak hours, providing aggregate benefits for the electric grid and participants themselves. The load management season begins on June 1 and continues through September 30 each year.

- The Residential Load Management Program provides customers with rebates for enrolling an existing qualifying internet-enabled smart thermostat for load management events or for the purchase and enrollment of a new internet-enabled smart thermostat through EPE’s online website. Participants who enroll, voluntarily allow EPE to control their smart thermostat to relieve peak load during the time of the event.

- The Commercial Load Management Program allows participating customers to provide on-call, voluntary curtailment of electric consumption during peak demand periods in return for incentive payments. This program is designed to target commercial participants from the educational, government, and private commercial sector with an average demand greater than 100 kW.

Table 10 shows EPE's New Mexico EE Portfolio of Programs and their Average Estimated Useful Life ("EUL").

Table 10. Current Portfolio New of Mexico EE/LM Programs and Program EUL

Program	Estimated Useful Life[1]
Residential Programs	
LivingWise®	9
Residential Comprehensive	15
Residential Lighting	12
ENERGY STAR® New Homes	21
Residential Load Management	10
NM EnergySaver (Low Income)	16
Commercial Programs	
Commercial Comprehensive	14
SCORE Plus	14
Commercial Load Management	1

1. EUL values as identified by the statewide Measurement and Verification Evaluator for program year 2020.

Table 11 provides the actual verified savings for EPE's New Mexico EE/LM programs for 2015 to 2020 and provides anticipated savings for 2021 to 2024. The projected savings are based on EPE's Plan approved by Final Order in NMPRC Case No. 18-00116-UT. The gross megawatt (“MW”) and megawatt-hour ("MWh") projections do not include a peak demand coincidence factor adjustment that is used for load forecasting purposes reflected in the L&R.

Table 11. New Mexico Verified and Projected Participation, Impacts, and Budget for EE/LM Portfolio

Year	Annual Participants[1]	Annual MW Demand Savings (at Meter)	Annual MWh Energy Savings (at Meter)	Annual Rebate/ Incentive Costs	Annual Admin Costs[2]	Total Annual Program Costs
2015♦	42,654	3.681	15,729	$3,250,299	$1,455,948	$4,706,247
2016♦	44,279	5.897	18,213	$3,827,090	$1,670,719	$5,497,809
2017♦	165,050	2.501	12,729	$2,942,309	$1,508,575	$4,450,884
2018♦	163,177	3.664	17,217	$3,183,759	$1,882,557	$5,066,315
2019♦	210,695	4.892	16,549	$3,149,722	$1,966,960	$5,116,681
2020	66,303	7.032	22,166	$3,156,200	$1,765,885	$4,922,085
2021	48,852	7.959	14,405	$3,180,466	$1,933,180	$5,113,646

1. CFL & LED Program assumes 5 bulbs per participant
2. Includes Third Party Costs, Promotion Costs, Program Development Costs, and EM&V Costs

♦ Verified by Commission approved statewide EM&V contractor

3. Texas Energy Efficiency Programs

EPE has offered EE programs in its Texas service territory since 1999. EPE's Texas jurisdictional programs require a minimum annual demand reduction, as well as an associated minimum energy reduction based on a 20% capacity factor. In the Final Order of the PUCT Docket No. 50806, EPE's annual demand reduction goal for 2020 was 11.16 MW and its energy savings goal was 19,552 MWh. EPE achieved a demand reduction of 20.74 MW, which exceeded the demand goal by 85.84%, and an energy reduction of 30,670 MWh, which exceeded the energy goal by 56.86%. Currently, EPE offers five residential and three commercial EE programs in its Texas service territory.

Table 12 provides the actual verified demand and energy savings for EPE's Texas EE programs for 2015 through 2020 and provides the projections for 2021 and 2022. The 2021 and 2022 projections are based on the information provided in EPE's 2021 Energy Efficiency Plan and Report, PUCT Project No. 51672.

Table 12. Texas Verified and Projected Demand and Energy Savings

Year	Annual MW Demand Savings (at Meter)	Annual MWh Energy Savings (at Meter)
2015♦	12.305	22,283
2016♦	12.790	22,912
2017♦	15.285	23,312
2018♦	16.846	20,726
2019♦	14.181	21,054
2020♦	20.743	30,670
2021	16.691	23,479
2022	19.827	26,882

♦ Verified by Commission approved statewide EM&V contractor

4. Texas Residential and Commercial Load Management Programs

EPE's Residential and Commercial Load Management Programs engage utility customers to reduce their electricity use (load) during peak hours or under certain conditions, which in turn, can substantially reduce demand for electricity during EPE's peak hours, providing aggregate benefits for the electric grid and-participants themselves.

The load management season begins on June 1 and continues through September 30 each year.

D. Energy Storage Resources

The Commission Final Order in Case No. 19-00348-UT denied EPE's requested approval of a stand-alone 50 MW battery selected pursuant the 2017 All-Source RFP; and EPE's resource portfolio does not contain any existing utility scale energy storage resources[4]. However, in 2022, EPE plans to install a 100 MW Solar facility coupled with 50 MW battery storage which was approved in that docket. The integrated solar/storage system will firm solar output during specified peak hours of operation. The planned battery storage system will charge during low load hours and discharge the stored energy during peak hours to provide firm energy during peak hours. Battery storage is a relatively new and emerging technology that is continually being integrated into utility scale applications to provide greater flexibility

[4] EPE does own a 1 MW battery storage system coupled with the 3 MW Aggie Power project located at NMSU.

to the electrical system allowing for greater integration of solar and/or wind resources. Besides “firming” solar generation, battery storage can also help to balance electricity loads to avoid energy “curtailment” by shifting excess energy from low load hours to peak hours. Further, battery storage provides greater resilience to the system by providing backup power during an electrical disruption due to a generation resource contingency or in the case of a solar PV facility, a brief generation disruption from an intermittent weather condition such as passing clouds. Battery storage is a resource that EPE modeled in this 2021 IRP and will continue to model for future resource needs. Other types of energy storage include pumped-storage, hydropower, electromechanical storage, thermal energy storage, flywheel storage, and compressed air storage. These other types of technologies were not modeled in EPE’s 2021 IRP because these storage technologies, as compared to battery storage, are not yet cost effective and/or may not be suitable for the desert southwest conditions.

E. Reserve Margin and Reliability Requirements

1. Reliability Requirements

EPE's resource planning efforts consider the reliability requirements of the North American Electric Reliability Corporation ("NERC"), which is granted authority by the Federal Energy Regulation Commission ("FERC") to define reliability standards. The reliability standards are developed to reduce risks to the reliability and security of the grid.[5] There are six reliability standards that are most relevant to the Planning Process.

BAL-001 – "To control Interconnection frequency within defined limits."

BAL-005-1 – " This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error… "

BAL-002 - "To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values…"

BAL-002-WECC - To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions.

BAL-003 - "To require sufficient Frequency Response from the Balancing Authority to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored…"

[5] NERC. https://www.nerc.com/AboutNERC/Pages/default.aspx

TOP-001 - "To prevent instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences."

EPE efforts to ensure resource adequacy to serve peak load in a safe and reliable manner are founded, in part, with the above-mentioned reliability standards. Furthermore, 17.9.560.13 NMAC also addresses an electric utility's requirement to provide reliable service.

> *"The electric plant of the utility shall be constructed, installed, maintained, and operated in accordance with accepted good engineering practice in the electric industry to assure, as far as reasonably possible, continuity of service, uniformity in the quality of service furnished, and the safety of persons and property."*

Additionally, 17.9.560.13 (C) NMAC stresses the importance of resource adequacy to include a reserve margin.

> *"Adequacy of supply. The generating capacity of the utility's plant supplemented by the electric power regularly available from other sources must be sufficiently large so as to meet all normal demands for service and provide a reasonable reserve for emergencies."*

2. Reserve Margin Requirements

Electric utilities work to maintain year-round resource adequacy to their firm customers with reasonable reliability. As a result, each system must maintain an adequate supply of generation that not only will meet the maximum forecasted demand of its customers (i.e., the "peak" demand) but also provide for unforeseen events (e.g., transmission line outages, power plant outages, exceedance of peak load forecast, etc.). To accomplish these objectives, utilities acquire and operate more generation capacity than is needed to meet peak demand. The additional generation, above what is needed to meet peak customer demand, is called the planning reserve margin (“PRM”). Generally, there are two basic types of reserve margins: (i) planning reserve margins, which are the amount of installed capacity required in excess of forecasted annual peak firm demand, and (ii) operating reserve margins, which are the amount of actual generation capacity required in real-time, either with units carrying regulation and/or spinning reserves; or units offline but in reserve and capable of providing additional generation in order to meet real-time changes in load/demand and any unforeseen contingencies (e.g., transmission outage, generator forced outage, gas supply disruptions, etc.).

From a long-term planning standpoint, EPE previously established a reserve margin of 15% which was re-affirmed in 2015 by a third-party firm, E3, and EPE has been utilizing that reserve margin since then. As part of this IRP, EPE requested that E3 reassess its PRM requirements, and that analysis is described later in this report.

F. Existing Transmission Capabilities

EPE owns and operates extensive transmission resources to serve customer load from its local and remote generation, and from other interconnected resources throughout the WECC. EPE's high voltage ("HV") transmission system consists of 69 kilovolt ("kV") and 115 kV lines, and its extra high voltage ("EHV") transmission system consists of 345 kV, and 500 kV lines. These facilities are located in the following locations: within the EPE service territory, interconnected from its service territory to the western grid, or located near EPE's remote PVNGS generation. EPE's 345 kV system is the integral part of the transmission system used to import and export power to and from EPE's service area. EPE's transmission system is comprised of three key components:

- Local transmission - Several 345 kV, 115 kV, and 69 kV transmission lines that are interconnected within EPE's local electrical grid.
- Path 47 - Three major 345 kV transmission lines known as Path 47 used to import/export power between WECC and EPE (plus one 115 kV line wholly owned and utilized by Tri-State); and,
- Eddy County DC Tie - A single 345 kV transmission line that interconnects EPE's local transmission system to SPS, an Xcel Energy Company, system through a 200 MW High Voltage Direct Current ("HVDC") terminal.

More details on EPE's transmission system are explained in the following sections.

<u>Local Transmission</u>

EPE's local EHV and HV transmission system consists of 345 kV, 115 kV and 69 kV lines in and around El Paso, Texas, and Las Cruces, New Mexico. EPE's local EHV transmission system consists of several 345 kV transmission lines that move the power from EPE's Path 47 import path and the Eddy County HVDC Terminal (see below) and distributes that power for delivery to various points on EPE's local HV system. Most of EPE's major distribution substations are connected to at least two 115 kV and/or 69 kV transmission lines. This high level of networking increases the reliability of the system by allowing the power to re-route to other transmission lines during outages.

EPE's local generation is directly connected to the local HV transmission system at Newman in northeast El Paso; Rio Grande in Sunland Park, New Mexico; MPS in far east El Paso; and Copper in central El Paso. The power generated at these plants flows directly into the EPE HV transmission system and then flows to the customer loads through the distribution system.

Path 47

Path 47 consists of EPE's three major 345 kV transmission interconnections with other utilities that are located at: (1) West Mesa Switching Station near Albuquerque, New Mexico with Public Service Company of New Mexico ("PNM"); (2) Springerville Generating Station ("Springerville"); and (3) Greenlee Substation ("Greenlee"), (both in Arizona) with Tucson Electric Power Company ("TEP"). Path 47 also includes the Belen to Bernardo 115 kV line owned and wholly used by Tri-State Generation and Transmission Association, Inc. ("Tri-State").

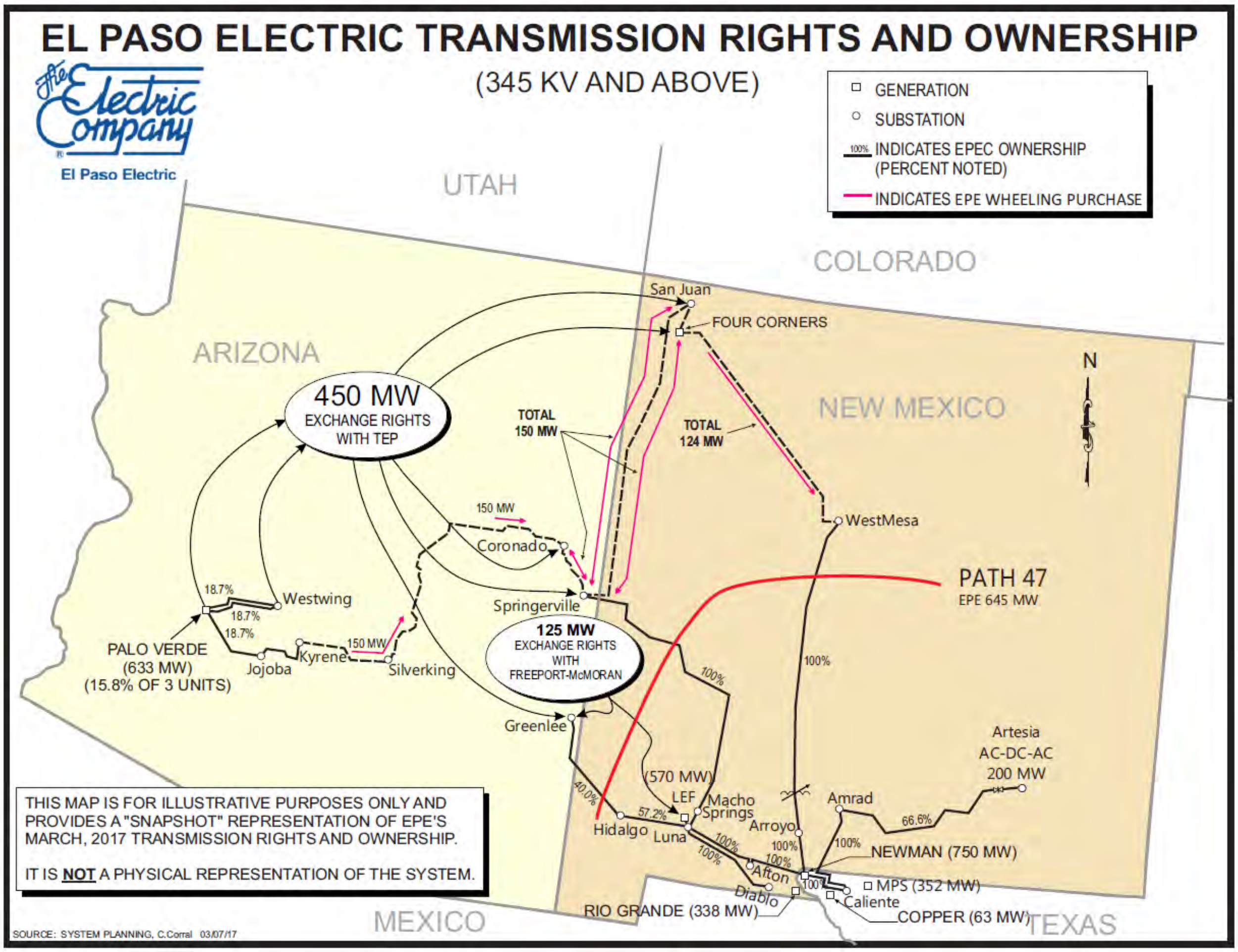
Eddy County DC Tie

EPE connects with SPS at the Eddy County HVDC Terminal near Artesia, New Mexico and has a 67% ownership in the Terminal and accompanying 345 kV transmission line connecting to the EPE system along with the joint owner, PNM. Through this HVDC Terminal, EPE can access resources, when available, in the Southwest Power Pool ("SPP") for delivery to EPE loads. Additionally, Empire substation is a new 345kV substation built along the Amrad—Eddy line, approximately 1 mile west of the HVDC Eddy substation. The Empire substation was built to allow for the interconnection of the Oso Grande Wind Farm. Improvements on the Amrad-Empire 345kV and the Empire-Eddy 345 kV lines allowed for an increase in its transmission capacity rating. The new line ratings are 400 MVA.

Along with the three components listed above, EPE has ownership of external EHV transmission, as described below.

EPE partially owns 500 kV transmission lines in the Arizona transmission system in connection with its PVNGS ownership and uses these lines for the delivery of its owned Palo Verde generation entitlement. These transmission lines are designated as the Palo Verde East Path (composed of three lines, two (2) Palo Verde to Westwing lines and the Palo Verde to Jojoba to Kyrene line) and are operated by Salt River Project ("SRP"). EPE utilizes a combination of an exchange and transmission agreement with TEP, and transmission wheeling purchased from SRP and PNM. In addition, EPE has a PPA with Phelps Dodge Energy Services, LLP, to import additional resources that are purchased on the market and to allow EPE to import additional Palo Verde power during times Path 47 is curtailed. Once the power is delivered to EPE's Balancing Area, it is delivered to EPE's load area through use of jointly (EPE and PNM) and wholly owned 345 kV lines in southern New Mexico and locally in the El Paso/Las Cruces area and then to EPE's local HV transmission system through EPE's existing 345/115 kV auto-transformers. Figure 8 shows a map of EPE's EHV Transmission system.

Figure 8 – EPE Transmission Rights and Ownership



Segments Which Comprise the EPE Extra High Voltage Transmission System

1. Energy Imbalance Market

EPE has elected to join the Western EIM with an implementation date of April 01, 2023. The CAISO EIM is a real-time market allowing participating entities the ability to leverage each other's online and available resources to regulate and address energy imbalances. The energy imbalances are primarily a result of the increasing variable generation (e.g., solar and wind) which has been added to the system. It is important to clarify that participation in the EIM does not provide additional resources for the purpose of meeting peak load. Each participant is required to have adequate resources to meet its peak load and regulating requirements. The EIM allows for co-utilization of each entities regulating reserves and potentially optimize dispatch/operating costs. It is not permitted for an entity to enter the EIM without adequate resource supply, as it may result in a burden to the EIM. As such, utilities are required to identify and secure adequate firm resources to meet peak load and reserve requirements before entry.

Therefore, EPE's decision to join the EIM still necessitates EPE, to continue with its Planning Process to plan for adequate resources to meet EPE's load requirements.

2. Wheeling Agreements

EPE purchases transmission to serve its native load from PNM and SRP. EPE has executed long-term, firm point-to-point transmission service agreements with PNM and SRP. EPE has also executed a Power Exchange and Transmission Agreement with TEP. These services are described below:

<u>Transmission Services Purchased by EPE from PNM</u>

EPE has a transmission service agreement under PNM's Open Access Transmission Tariff ("PNM OATT") for 104 MW firm, point-to-point transmission from Four Corners Power Plant ("FCPP") 345 kV Switchyard to West Mesa 345 kV Switching Station from July 1, 2017 to July 1, 2022 and is currently working on an extension agreement to roll over through July 1, 2027. In addition, EPE has rolled over its grandfathered, firm 20 MW long-term rights under Service Schedule I of the 1966 Interconnection Agreement between EPE and PNM into Firm, Point-to-Point Transmission Service under PNM OATT with a term of June 1, 2019 to May 31, 2024. Both transmission purchases have an option to rollover. The Transmission Service described above is utilized by EPE to serve its native load.

<u>Transmission Services Purchased by EPE from SRP</u>

EPE has a non-OATT, firm transmission service agreement for 150 MW from Kyrene 230 kV Switchyard to Coronado 500 kV Switchyard with SRP for the delivery of a portion of EPE's PVNGS entitlement or for the direct substitution of power and energy from any other source to serve EPE's native load. This Agreement remains in effect concurrent with the Arizona Nuclear Power Project Participation Agreement, unless earlier terminated by the parties.

Transmission Service Exchange Agreements between EPE and TEP

Under the Tucson-El Paso Power Exchange and Transmission Agreement, EPE has a non-OATT, executed power exchange and transmission agreement with TEP in which EPE delivers from its share of PVNGS generating units, and TEP receives, amounts of capacity with corresponding energy at the Palo Verde Switchyard or the Westwing Substation of 300 MW. EPE has an additional Exchange for up to 150 MW pursuant to a non-OATT agreement under the EPE-TEP Interconnection Agreement. EPE receives such capacity and energy at Greenlee, Springerville, Coronado, San Juan, or FCPP in total amounts equal to that scheduled to TEP at the Palo Verde Switchyard or Westwing Substation.

Under the Tucson- El Paso Power Exchange and Transmission Agreement, TEP assigned to EPE 150 MW of transmission rights in TEP's 345 kV system between Springerville and either of FCPP, San Juan, or Coronado; this assignment of rights is bi-directional. The term of this Agreement is consistent with the life of PVNGS Units 1, 2, and 3.

3. Existing and Under Construction Transmission Facilities

EPE's transmission facilities include transmission lines (internal and external to EPE), substation transformers, autotransformers and a Phase Shifting Transformer at Arroyo Substation. EPE owns and operates 216 miles of 69 kV transmission lines, 522 miles of existing 115 kV transmission lines, and 946 miles of 345 kV transmission lines. In addition, EPE jointly owns 165 miles of 500 kV transmission lines in Arizona.

Attachment C-1 provides information on EPE's transmission facilities. This includes a list of EPE's existing and under construction transmission facilities, including associated switching stations and terminal facilities, and transfer capability limitations. Individual line limitations (ratings) on EPE's transmission network may affect future siting of supply-side resources.

EPE engages in various transmission projects in its local area to maintain, upgrade, and expand EPE's transmission system to ensure the reliability of the system and to provide for future load growth. EPE produces a 10-year Transmission Expansion Plan every year in accordance with Attachment K of EPE's OATT. A summary of this plan is posted on EPE's web site.

4. Location and Extent of Transfer Capability Limitations

EPE's primary interconnection is to the WECC. EPE's ability to import its remote generation resources is governed by the transmission capacity of its WECC interconnection, termed WECC Path 47 or the Southern New Mexico Transmission System ("SNMTS"). EPE is physically interconnected to the SPP through its HVDC tie. EPE has transmission ownership of 133 MW over the HVDC tie and ownership of 645 MW of firm capacity over Path 47.

The Total Transfer Capability ("TTC") of a transmission path is the maximum amount of power that can be transferred on that path, i.e., from one point on the system to another point on the system in a reliable manner while meeting a specific set of defined pre-and post-contingency system conditions. This capability is defined by the worst contingency for the defined point-to-point path and the thermal, voltage, and/or stability limits of that path. The Available Transfer Capacity ("ATC") is a measure of the transfer capability available on a transmission path for commercial activity over and above already committed uses and established capacity and reliability margins.

EPE makes ATC determinations on a real-time basis. ATC values are posted on the OATI OASIS website for the EPE transmission system with all transmission lines in-service. TTC, however, will change from time to time to reflect both scheduled and unscheduled, or forced, outages. The amount of curtailments for EPE's major transmission system outages are given on EPE's OASIS.

Brief descriptions of the Southern New Mexico Import Capability ("SNMIC") and the capacity of EPE's external line segments are provided below.

Additional transmission data pertaining to EPE's transmission facility capability and planning standards are posted on EPE's website at www.epelectric.com. These include "*Principles, Practices and Methods for the Determination of Available Transmission Capacity for El Paso Electric Company*" ("ATC Document") is found on EPE's website. The ATC Document explains EPE transmission facility capabilities and how EPE operates its New Mexico and Texas transmission system as a whole.

5. SNMIC Limitation Determination

Total and available transmission capabilities for the primary 345 kV path which connects the EPE Balancing Area ("BA") to neighboring BAs operated by PNM and TEP are based on the SNMIC. The individual lines into the EPE BA – the West Mesa 345 kV transfer path between EPE and PNM, and the Springerville 345 kV and Greenlee 345 kV transfer paths between EPE and TEP – are collectively referred to as

WECC Path 47, or the SNMTS. This is a WECC Accepted Path with a rating that is less than the sum of the capabilities of the individual lines.

The SNMIC is determined through real-time dynamic nomogram equations that incorporate the state and configuration of the southern New Mexico system at any instant of time, and using dynamic adjustments, reflect changes in that system state. These dynamic adjustments reflect southern New Mexico system variables such as: the status and output of EPE's and other local generating units, power factor for the EPE load area, status of 345 kV reactors in the SNMTS, and the amount and direction of power flows over selected EPE transmission lines.

The maximum amount of firm import capability into the SNMTS over the 345 kV interconnections (plus the capacity of the Tri-State Belen-Bernardo 115 kV line) is 940 MW. The allocation of this firm capability among the owners of the SNMTS is:

EPE	645 MW
PNM	185 MW
Tri-State	110 MW

To the extent the SNMIC decreases below the maximum firm capacity value due to a change in the status of EPE-owned transmission variables (listed above), EPE is obligated to decrease its portion of SNMIC. Likewise, if the status of the EPE-owned transmission variables allows for a SNMIC greater than the maximum firm capacity of 940 MW, only EPE can use that additional capacity on a non-firm basis.

As the operating agent of the SNMTS, EPE is also responsible for notifying other owners if their imports exceed their rights and whether curtailment of imports is required.

6. External Transmission Limitation Determination

As mentioned above, EPE partially owns 500 kV transmission lines in the Arizona transmission system in connection with its PVNGS ownership and uses these lines for the delivery of its owned Palo Verde generation entitlement. Salt River Project performs the technical studies to evaluate the Palo Verde East rating, with agreement of the other Palo Verde East path owners, PNM, and Arizona Public Service Company ("APS"). EPE posts this path with the ratings determined through these studies on its OASIS. A full explanation on how TTC and ATC on these paths are determined can be found in the ATC Document.

7. Transmission Coordinating Groups

As a Class 1 member (transmission provider) of WECC, EPE's transmission planning activities are coordinated through several regional groups that include WECC committees under the Reliability Assessment Committee ("RAC"). These groups include the BPS Planning Roles Task Force ("BPSPRTF"), the Loads and Resources Task Force ("LRTF"), the Joint Synchronized Information Subcommittee ("JSIS"), the Modeling and Validation Subcommittee ("MVS"), the Production Cost Data Subcommittee ("PCDS"), the Production Cost Modeling Subcommittee ("PCMS"), the System Review Subcommittee ("SRS"), and the Studies Subcommittee ("StS"). In addition, EPE is a member of the General Electric Positive Sequence Load Flow ("PSLF") Users Group, the regional transmission planning group WestConnect, and the Southwest Area Transmission ("SWAT") Subregional Planning Group.

Through WestConnect, EPE and other WestConnect members participate in the regional transmission planning process detailed in FERC Order 1000 and in Attachment K of EPE's Transmission Tariff (OATT). The WestConnect footprint includes Arizona, part of California, Colorado, part of Montana, part of Nebraska, New Mexico, Nevada, part of South Dakota, and part of Wyoming.

8. Other Resources Relied Upon: Pooling and Coordination Agreements: Reserve Sharing Group

In addition to the wheeling agreements described above in Section III.F.1, EPE is also a member of the Southwest Reserve Sharing Group, ("SRSG"). SRSG is a NERC registered entity that administers compliance with the BAL-002 and EOP-011 requirements. Members of the SRSG share operating contingency reserve requirements to mitigate the amount of contingency reserves individual members would need to carry if not part of the SRSG. EPE follows the SRSG Operating Procedures for calculating and reporting the Spin and Non-Spin hourly reserve values.

Conclusion and Discussion

As described above, EPE is physically located in the far southeastern corner of the WECC region and is constrained by transmission import limits. Firm import transmission capacity is limited to two specific paths: Path 47 and the Eddy County HVDC Tie. In other words, EPE is not in a position to wheel power through its service territory from multiple transmission paths but is more of a terminal point in the WECC region. Import capacity outside of these paths is non-firm and cannot be considered in long-term resource planning because availability of non-firm transmission capacity is unknown. EPE considers these constraints when performing its long-term planning and when establishing an appropriate reserve margin. These considerations, in conjunction with risk of outages due to transmission maintenance or transmission system failure, require further review when evaluating the siting of future generation. Due to the transfer capability limits of Path 47 and the Eddy County DC Tie, future supply side resources may be more optimally be sited within EPE's service territory. Any resources sited outside EPE's service territory likely would require transmission investments to ensure firm transmission import capacity.

G. Back-Up Fuel Capabilities and Options

Presently EPE has three primary resource types, nuclear, gas, and solar energy resources. The Newman and Montana Power Stations have dual gas pipeline interconnections providing added reliability and mitigating the potential for gas fuel supply disruption. The four Montana Power Station units are also dual fuel capable with the ability to utilize diesel fuel oil in case of gas fuel supply disruption. In 2022, EPE will increase its solar energy capacity as well as introduce a 50 MW battery storage resource, further increasing its diversity. Table 7 identifies plants that are dual fuel capable. Further discussion on dual fuel capability is found in Section VII, "Description of the Resource and Fuel Diversity."

EPE’s resource diversity in terms of resource type, dual pipeline access, and alternate diesel fuel oil capabilities allowed EPE to meet customer demand needs during an unprecedented winter storm the week of February 14th, 2021. The winter storm plunged the state of Texas into subfreezing temperatures causing massive power outages overwhelming the state’s electricity infrastructure. The winter storm caused disruptions to the region’s natural gas fuel supply causing overlapping declaration of critical operation conditions to both its Interstate and Intrastate natural gas pipelines. To retain the integrity and reliability of its system after experiencing a loss of its natural gas supply, EPE switched all the Montana units to fuel oil during the week of the winter storm. EPE was also able to save customers millions of dollars in fuel costs by burning fuel oil instead of procuring additional natural gas supply in the day-ahead market.

IV. CURRENT LOAD FORECAST

A. Forecast Summary

The 2021 Load Forecast predicts expected, upper, and lower bounds for energy and peak demand, for EPE's native and total systems. The forecast is generated for the 20-year period of 2021-2040 (see Attachment B-1). The 2021 expected (base) forecast predicts 10- and 20-year compound annual growth rates ("CAGR") of 1.1% and 1.5% for native system energy, respectively. The 2021 expected forecast predicts 10- and 20-year CAGR of 0.9% and 1.7%, respectively, for native system peak demand. EPE's native system consists of New Mexico and Texas jurisdictional retail load and the contractual Rio Grande Electric Co-Operative ("RGEC") wholesale load EPE serves interconnected to its Texas service territory. Native system load plus line losses incurred from off-system wheeling of EPE's power (losses-to-others) make up EPE's total system. The following information is provided as required by the17.7.3.9 (D) NMAC.

B. Load Forecast Methodology and Inputs

EPE's 2021 Load Forecast is developed from several components. The forecast takes into consideration factors such as historical energy sales, average weather, demographic trends, economic activity, existing rate design, distributed solar generation, energy efficiency, load management, light-duty electric vehicle adoption, saturation of refrigerated air conditioning, potential changes in customers, and changes in consumption patterns resulting from COVID-19.

The largest component of the load forecast is the econometric modeling of retail energy sales. Econometrics is the application of mathematics and statistical methods to conduct economic analyses and developing forecast trends. EPE uses econometrics to provide an empirical estimate of the relationship between economic, weather, and demographic data, and electricity consumption. EPE's econometric forecasting models relate customer electricity usage to service area trends in population, weather, and local economic indicators to estimate future electricity sales. For example, population, gross metropolitan product (GMP), and weather are typical drivers of electricity sales; more customers and increased GMP, which represents an increased production of goods and services in the region, will typically result in higher electricity demand. The primary data sources for EPE's econometric models are IHS Markit, AccuWeather, and EPE's customers' historical usage/load data. IHS Markit provides the underlying assumptions of the economic and demographic data that are used in developing EPE's forecasted energy and peak demand. AccuWeather provides EPE with regional weather Cooling Degree Days (CDD) and Heating Degree Days (HDD) used in weather normalizing historical sales and producing "normal" weather values for the forecast period. AccuWeather’s data comes from the National Oceanic and Atmospheric Administration (NOAA) sites in El Paso and Las Cruces and have been adjusted for missing values and other anomalies via AccuWeather. EPE also uses the historical usage/load data for each of its major customer classes.

The 2021 Load Forecast employs monthly and annual methodologies to develop its models for EPE's major customer classes. The monthly energy forecasts are based on econometric modeling of the residential, small commercial & industrial, and government load sectors in both Texas and New Mexico. The annual energy forecasts are based on econometric modeling of the large commercial & industrial sectors for both Texas and New Mexico for a total of eight separate econometric energy forecasts. Each of the eight models is estimated using Ordinary Least Squares as a function of weather, economic, and demographic variables.

Residential class sales are estimated using a use per customer ("UPC") methodology. The estimated UPC is then multiplied by the customer forecast to arrive at total kWh forecast for this customer class. The energy forecasts for small commercial & industrial, large commercial & industrial, street lighting, and government classes are estimated using total kWh. The final models are selected based on various key measures such as R^2, t-statistics, the Durbin-Watson test, and the F-statistic.

The conversion from traditional streetlights to more efficient LED lights that the cities of El Paso and Las Cruces undertook caused a significant change in the historical dataset for the Street Lighting classes which make econometric modeling of these classes difficult. As a result, the energy forecasts for the Texas and New Mexico Street Lighting class are calculated using forecasted growth for total households in each city.

Customer forecast equations are also estimated for each of the customer classes using econometric models, except for the large commercial & industrial and street lighting classes. The number of large commercial & industrial and street lighting customers is set at current levels, unless it is known that specific customers are planning to enter or leave the service territory at a specific future date. For these reasons, EPE maintains a customer count for this class constant with 2020 year ending levels.

In instances where adequate data is not available to support econometric forecasts, EPE relies on sales estimates based upon recent experience, and information from large industrial customers to make adjustments that are based on known or expected changes in load. Examples of these adjustments in the 2021 Load Forecast include changes in load for distributed solar generation, energy efficiency, and light-duty electric vehicles.

The econometric sales forecasts are adjusted to reflect the effects of energy efficiency, distributed solar generation, and light-duty electric vehicles that are otherwise not represented in the historical database. Energy efficiency effects include the results of EPE-sponsored energy efficiency and load management programs that are required in its Texas and New Mexico jurisdictions. The distributed generation effects accounts for customer owned solar generation in the residential, small commercial & industrial, and government customer classes. The light-duty electric vehicle adjustments include forecasted incremental load from electric vehicle adoption in EPE’s service territory. The estimates for energy impacts from efficiency energy savings, distributed generation, and light-duty electric vehicle are accounted for in the annual retail sales energy forecasts in developing the expected native system energy value. In addition to these adjustments, the contractual RGEC load is also incorporated into the forecast; RGEC is a wholesale/native load customer.

EPE combines annual retail sales prior to any adjustments, sales to RGEC, and company use, to calculate native system losses using a system line loss rate. These system losses must be included with sales at the meter to accurately calculate the total energy requirement needed to deliver electricity to EPE's customers. Additionally, line losses are incurred from off-system wheeling of EPE's power (losses-to-others). These losses are estimated based on historical trends of the system and are added to the native system energy to arrive at the total system energy value.

After the energy forecast is calculated, a constant native system load factor is applied to the native system energy to calculate the expected native system peak demand over time.

Mathematically, the load factor equation is:

$$LF = Energy / (Demand \times Hours)$$

Solving for Demand, the equation becomes

$$Demand = Energy / (LF \times Hours)$$

The constant load factor methodology utilizes the native system load factor from the previous year and applies it to the native system energy forecast to create the annual native system peak demand forecast. As is done with the expected native system energy, the expected native system peak demand is also adjusted for energy efficiency, distributed solar generation, and light-duty electric vehicle measures that impact system demand. The estimated peak demand for both interruptible customers and wheeling losses-to-others are then accounted for to obtain the total system peak demand.

1. Energy and Coincident Peak Demand by Major Customer Class

EPE has provided the load forecast for each year of the planning period. The projected annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states, are provided in Attachments B-2 and B-3, respectively. The projected annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system are provided Attachment B-4. The typical historic day load patterns on a system-wide basis for each customer class are provided in Attachment B-5.

C. Weather Adjustment Detail

Weather is a major factor in determining EPE's energy sales and peak demand. The 2021 Load Forecast assumes that 10-year average weather conditions (2011-2020) exist throughout the forecast period (2021-2040). The 10-year average weather data is used as a baseline for comparing current weather data and creating "normal weather" conditions in the forecast period.

The two weather variables most significant to the energy models are Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"). The HDD and CDD variables are based on a 65°F base. That is, if the average temperature for the day (maximum plus minimum, divided by two) is over 65°F, the difference is the number of CDD for that day. Likewise, if the average is less than 65°F, the difference is the number of HDD for that day.

Because CDD and HDD are recorded on a calendar month basis while booked month sales are recorded over 18 billing cycles that normally include portions of two calendar months, it was necessary to adjust these calendar month variables into variables that correspond to EPE's billing cycles. This adjustment was accomplished using two-month moving average CDD and HDD variables.

D. Demand-Side Savings Detail

EPE's energy and demand forecasts are adjusted to reflect EPE-sponsored EE/LM programs that are required in EPE's Texas and New Mexico jurisdictions. EPE's Energy Efficiency department develops these savings by jurisdiction and customer class.

EPE does not directly adjust its forecast models for demand-side savings that are not attributable to actions by EPE. Demand-side management that is attributable to actions other than EPE, such as consumers who, without any EPE incentive, decide to transition to lower wattage light bulbs or energy efficient appliances, have savings that are unquantifiable. However, the historical sales data used in EPE's econometric forecasts does have embedded in it any organic or naturally occurring demand-side savings that may have occurred. Therefore, using historical data, EPE's models and forecasted estimates of energy and demand do indirectly account for organic demand-side management.

E. Distributed Generation

EPE forecasts future customer count growth, sales, and generation capacity (nameplate and production at the time of system peak) for customers who own or lease distributed generation solar systems. These projections are made monthly for a 20-year period (2021-2040) by jurisdiction and by impacted customer classes. The econometric sales and demand forecasts are adjusted to reflect these forecasted distributed generation effects that are not represented in the historical database.

The distributed generation effects include customer owned or leased solar generation in the residential, small commercial & industrial, and government customer classes. Customer forecasts for the above-mentioned customer classes drive the final energy and demand estimates for distributed generation. The median nameplate capacity for distributed generation systems in the region along with their observed capacity factors are applied to these customer forecasts to arrive at the energy and demand forecasts. A coincidence factor of 49 percent is used to account for the expected production of distributed generation systems at the time of the system peak relative to the maximum total production capacity of these units. Furthermore, an annual degradation factor of 0.5 percent is used to account for the degradation in the output of solar panels over time. The estimates for distributed generation energy impacts are accounted for in the annual retail sales energy forecasts in developing the expected native system energy value.

The econometric sales and demand forecasts are adjusted to reflect future distributed generation effects not represented in the historical database.

F. Light-Duty Electric Vehicles

EPE light-duty electric vehicle projections for energy sales and demand impacts are calculated for a 20-year period by jurisdiction and only impact the residential customer class. Estimates indicate a single light-duty vehicle can consume an average of 3,870 kWh per year, equivalent to half of the average annual energy consumption of a residential household. Demand impact can vary widely depending on the type of charger, creating demand spikes between 1.2 and 19.2kW per vehicle. The forecast assumes an average demand impact of 7.2 kW per vehicle to estimate future demand impacts.

In addition to the light-duty electric vehicle forecast, EPE also forecasts load requirements for medium and heavy-duty electric vehicles, however, only the light-duty vehicle forecast was included in the current long-term forecast because their load is more present and growth trends are clearer than the other vehicle categories over the forecast period.

G. Load Forecast Scenarios

In addition to the expected (base) estimates, the 2021 Load Forecast also estimates both upper and lower (high and low) scenarios. These upper and lower scenarios are produced for both native system energy and native system peak demand to account for future uncertainty. Upper and lower scenarios around energy and demand base forecasts can be estimated in various ways, such as by using statistical methods as well being driven by extreme weather scenarios. EPE calculates upper and lower scenarios using confidence intervals as well as a variety of extreme weather scenarios. Both the upper and lower scenarios shown in Attachment B-1 are built using a confidence interval with a 95% confidence level. EPE uses confidence intervals with a high confidence level as the preferred method for building upper and lower bands because it captures more uncertainty in future periods. The increased uncertainty helps capture possible future changes to electricity consumption in addition to that of weather, such as: changes in rate structures, economy, demography, and taste and preferences. Although EPE uses confidence intervals to produce the upper and lower-case forecasts in the 2021 Load Forecast, EPE also has provided below upper and lower-case forecasts using extreme historical weather for comparison purposes. These scenarios pull the most extreme historical weather months over a 10-year historical period, both on the high and low side, and combine them to form a calendar year of the most extreme monthly weather. This weather is then applied to future years to produce energy and peak demand estimate bands around the expected case. Figures 9 and 10 contain a graphical representation of the low and high forecast scenarios of native system energy and native system peak demand.

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Figure 9 – Native System Energy Forecast Scenario Comparison

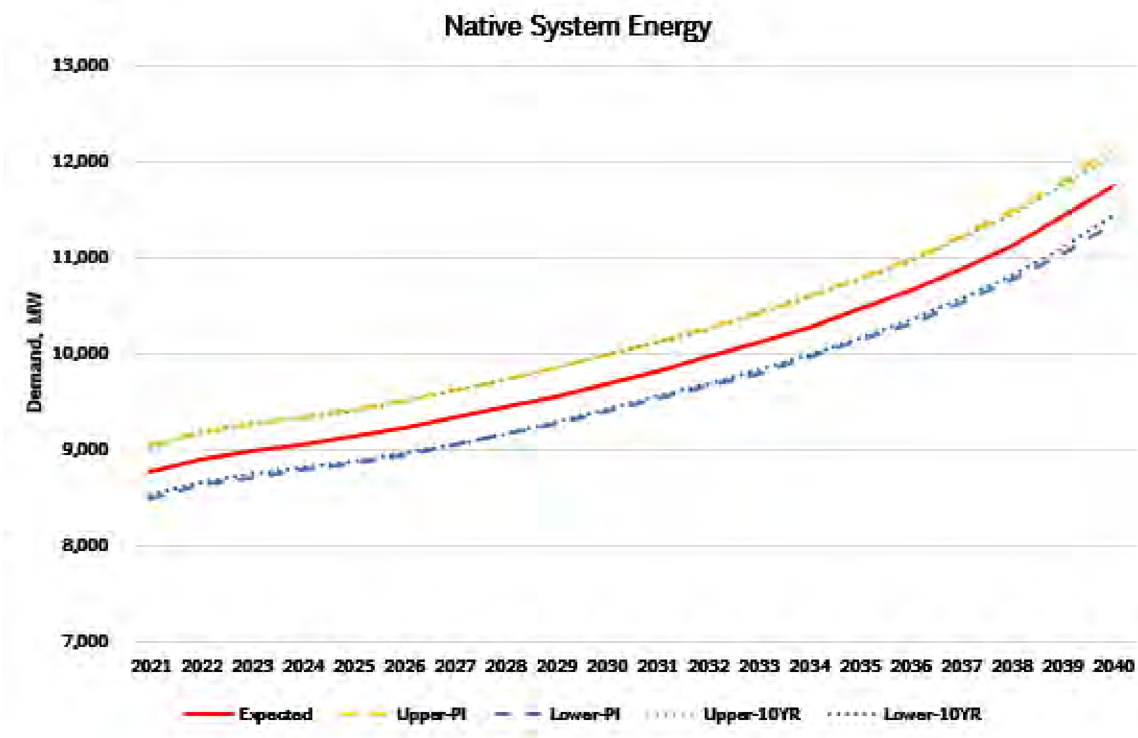
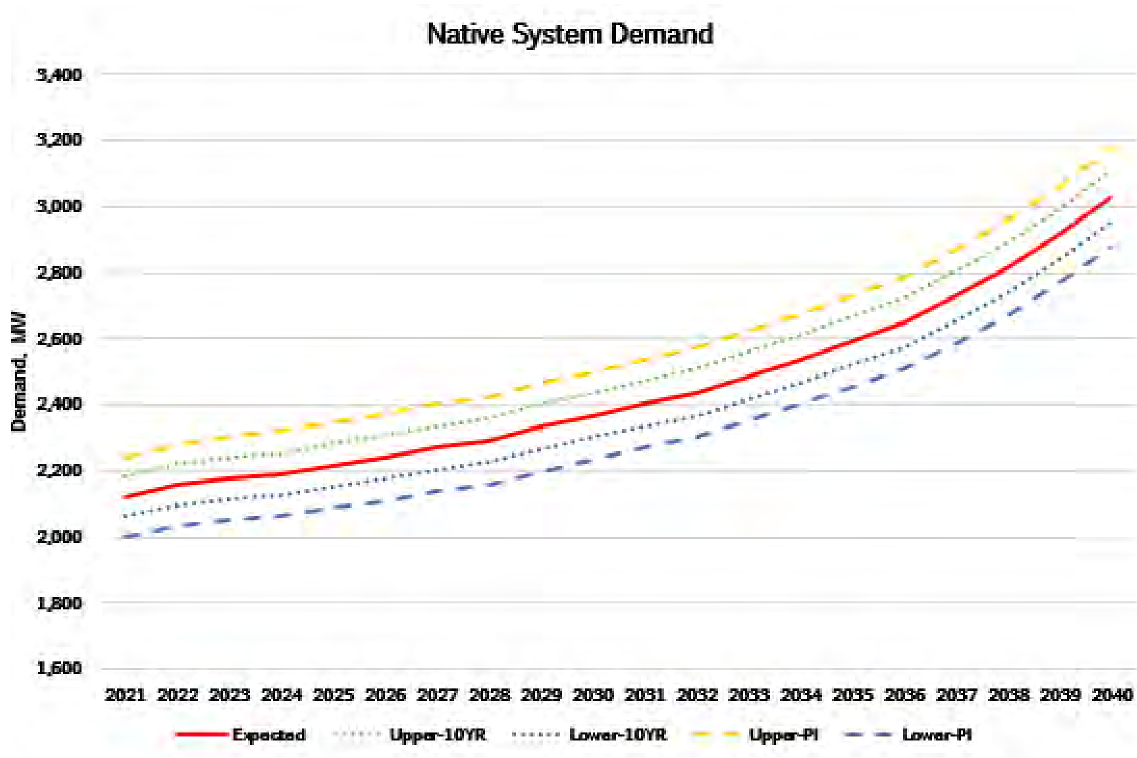


Figure 10– Native System Peak Demand Forecast Scenario Comparison



From Figures 9 and 10 above, one can see that the extreme weather upper and lower bands (Upper-10 YR and Lower-10 YR) are narrower than that of the confidence interval bands (Upper-CI and Lower-CI). As mentioned previously, EPE constructed confidence intervals with a high confidence level to capture more uncertainty in future periods. The increased uncertainty helps capture possible future changes to electricity consumption in addition to extreme weather, such as: changes in rate structures, economy, demography and taste and preferences.

EPE's expected forecast predicts 10- and 20-year CAGR of 1.1% and 1.5% for native system energy, respectively. The expected forecast also predicts 10- and 20-year CAGR of 0.9% and 1.7%, respectively, for native system peak demand. The upper forecast scenario predicts 10- and 20-year CAGR of 1.4% and 1.7% for native system energy, respectively. The upper forecast also predicts 10- and 20-year CAGR of 1.2% and 1.8%, respectively, for native system peak demand. The lower forecast scenario predicts 10- and 20-year CAGR of 0.8% and 1.4% for native system energy, respectively. The lower forecast scenario predicts 10- and 20-year CAGR 0.6% and 1.5%, respectively, for native system peak demand.

H. Historical Forecast Accuracy and Comparison

Tables 13 and 14 below contain the annual forecast of energy sales and system peak demand made by EPE to the actual energy sales and system peak demand experienced by EPE for the five years preceding 2021, (2015-2020). Please note that the energy data in Table 13 is total energy sales, which is composed of energy sales "at meter" for both retail and wholesale customers.

Table 13 - Total Sales (MWh) Historical Forecast Accuracy

	Total Sales (MWH)					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Actual	**7,867,229**	**7,874,577**	**7,906,846**	**8,093,667**	**8,063,475**	**8,162,678**
2016 Forecast		7,956,182	8,078,403	8,210,150	8,324,909	8,454,899
2017 Forecast			7,967,828	8,034,627	8,092,888	8,166,668
2018 Forecast				7,958,254	8,040,954	8,117,977
2019 Forecast					8,187,471	8,272,764
2020 Forecast						8,105,289

	Percent Difference				
2016 Forecast	1.04%	2.17%	1.44%	3.24%	3.58%
2017 Forecast		0.77%	-0.73%	0.36%	0.05%
2018 Forecast			-1.67%	-0.28%	-0.55%
2019 Forecast				1.54%	1.35%
2020 Forecast					-0.70%

Table 14 - Native System Demand (MW) Historical Forecast Accuracy

Native System Demand (MW)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020***
Actual	**1,794**	**1,892**	**1,935**	**1,929**	**1,985**	**2,173**
2016 Forecast		1,811	1,846	1,878	1,907	1,933
2017 Forecast			1,927	1,946	1,963	1,978
2018 Forecast				1,964	1,988	2,005
2019 Forecast					1,972	1,989
2020 Forecast						2,015

Percent Difference						
2016 Forecast		-4.29%	-4.60%	-2.63%	-3.93%	-11.04%
2017 Forecast			-0.43%	0.87%	-1.11%	-8.96%
2018 Forecast				1.82%	0.15%	-7.72%
2019 Forecast					-0.65%	-8.48%
2020 Forecast						-8.19%

* Note: The difference between the forecasted native system peak for 2020 and the actual 2020 native system peak are due to changes in consumption pattern resulting from COVID-19 and extreme summer weather, which led to a record native system demand growth of 188 MW.

Table 15 contains a comparison of the annual forecast of energy sales and system peak demand in EPE's most recently filed resource plan (2018) to the annual forecasts in the current resource plan (2021).

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Table 15. Annual Forecast Energy Sales Versus Peak Demand

Total Energy Sales Forecast Comparison (MWh)		
	2018 Forecast	2021 Forecast
2018	7,958,254	
2019	8,040,954	
2020	8,117,977	
2021	8,197,532	8,192,517
2022	8,293,704	8,316,878
2023	8,394,406	8,395,619
2024	8,492,212	8,460,016
2025	8,592,592	8,528,249
2026	8,699,571	8,611,976
2027	8,810,080	8,709,868
2028	8,920,613	8,812,014
2029	9,039,504	8,924,130
2030	9,169,955	9,046,082
2031	9,294,405	9,171,235
2032	9,428,932	9,299,848
2033	9,572,253	9,441,968
2034	9,722,605	9,598,635
2035	9,875,965	9,769,099
2036	10,035,608	9,953,933
2037	10,203,914	10,158,865
2038		10,390,825
2039		10,656,933
2040		10,974,528

Peak Demand Forecast Comparison (MW)		
	2018 Forecast	2021 Forecast
2018	1,964	
2019	1,988	
2020	2,005	
2021	2,034	2,121
2022	2,061	2,155
2023	2,090	2,177
2024	2,111	2,190
2025	2,146	2,216
2026	2,176	2,240
2027	2,206	2,269
2028	2,231	2,292
2029	2,270	2,331
2030	2,306	2,367
2031	2,340	2,404
2032	2,370	2,436
2033	2,416	2,488
2034	2,456	2,538
2035	2,498	2,593
2036	2,533	2,648
2037	2,586	2,728
2038		2,813
2039		2,913
2040		3,028

V. LOAD AND RESOURCES TABLE

The L&R illustrates the balance of EPE's available resources versus the annual forecasted loads. EPE's long-term future resource needs are driven by unit retirement and system load growth. The Forecasted loads are based on the 2021 Load Forecast for the L&R and is shown in Figure 11. This is the starting point for assessing any deficiencies in resources given planned retirement and system load growth. This initial L&R does not select future resources, the final L&R with future resources as defined via this IRP process is provided at the conclusion of this report.

Figure 11. Initial L&R

El Paso Electric Company
Loads & Resources 2021-2040
Initial 2021 IRP

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1.0 GENERATION RESOURCES																				
1.1 RIO GRANDE	323	278	232	232	232	232	232	232	232	232	232	232	232	88	88	88	88	88	88	88
1.2 NEWMAN	729	729	811	811	811	811	494	494	494	494	494	494	494	494	494	494	494	494	494	494
1.3 COPPER	63	63	63	63	63	63	63	63	63	63	-	-	-	-	-	-	-	-	-	-
1.4 MONTANA	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
1.5 PALO VERDE	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622	622
1.6 RENEWABLES	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
1.7 STORAGE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
1.9 INTERRUPTIBLE	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
1.10 LINE LOSSES FROM OTHERS	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**2,158**	**2,113**	**2,149**	**2,149**	**2,189**	**2,189**	**1,872**	**1,872**	**1,872**	**1,872**	**1,809**	**1,809**	**1,809**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**	**1,665**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE	73	72	72	72	71	71	70	70	69	69	69	56	55	55	23	22	20	6	6	6
2.2 NEW RENEWABLE PURCHASE	-	43	42	42	42	42	41	41	41	41	41	40	40	40	40	40	39	39	39	39
2.3 NEW RENEWABLE/ BATTERY PURCHASE	-	75	75	74	74	74	73	73	72	72	72	71	71	71	70	70	70	69	69	69
2.4 NEW BATTERY PURCHASE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2.5 MARKET RESOURCE PURCHASE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2.0 TOTAL RESOURCE PURCHASES	**73**	**190**	**189**	**188**	**187**	**186**	**185**	**184**	**183**	**182**	**181**	**167**	**166**	**166**	**133**	**132**	**128**	**115**	**114**	**114**
3.0 FUTURE RESOURCES																				
3.1 RENEWABLE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.2 RENEWABLE/STORAGE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.3 GAS GENERATION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3.0 TOTAL RESOURCE PURCHASES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2,231**	**2,303**	**2,338**	**2,337**	**2,376**	**2,375**	**2,057**	**2,056**	**2,055**	**2,054**	**1,990**	**1,976**	**1,976**	**1,831**	**1,798**	**1,797**	**1,794**	**1,780**	**1,779**	**1,779**
5.0 SYSTEM DEMAND																				
5.1 NATIVE SYSTEM DEMAND	**2,139**	**2,190**	**2,228**	**2,256**	**2,297**	**2,337**	**2,380**	**2,418**	**2,473**	**2,524**	**2,576**	**2,623**	**2,690**	**2,754**	**2,825**	**2,895**	**2,990**	**3,089**	**3,204**	**3,334**
5.2 DISTRIBUTED GENERATION	(9)	(19)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5.3 ENERGY EFFICIENCY	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(62)	(69)	(77)	(85)	(92)	(100)	(108)	(115)	(123)	(131)	(138)	(146)	(154)
6.0 TOTAL SYSTEM DEMAND (5.1 + 5.2 + 5.3)	**2,122**	**2,156**	**2,183**	**2,203**	**2,237**	**2,269**	**2,304**	**2,335**	**2,382**	**2,425**	**2,470**	**2,509**	**2,568**	**2,625**	**2,688**	**2,750**	**2,837**	**2,928**	**3,036**	**3,158**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**109**	**147**	**156**	**134**	**139**	**106**	**(247)**	**(279)**	**(326)**	**(371)**	**(479)**	**(533)**	**(592)**	**(794)**	**(890)**	**(953)**	**(1,043)**	**(1,149)**	**(1,257)**	**(1,379)**
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	**318**	**323**	**327**	**330**	**336**	**340**	**346**	**350**	**357**	**364**	**370**	**376**	**385**	**394**	**403**	**413**	**426**	**439**	**455**	**474**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**(209)**	**(176)**	**(172)**	**(196)**	**(196)**	**(234)**	**(593)**	**(629)**	**(684)**	**(734)**	**(850)**	**(909)**	**(977)**	**(1,188)**	**(1,293)**	**(1,366)**	**(1,469)**	**(1,588)**	**(1,712)**	**(1,853)**

1. Generation unit retirements are consistent with the 2018 IRP.
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2021 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. System demand is based on the 2020 Long-Term Forecast dated April 1, 2021.
10. Native System Demand includes EV load.

Unit Retirements

Rio Grande 6 (45MW) - December 2021 (2014)
Rio Grande 7 (46MW) - December 2022
Newman 1 (73MW) - December 2022
Newman 2 (73MW) - December 2022
Newman 3 (90MW) - December 2026
Newman 4 CC (227MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (144MW) - December 2033

Renewable Purchases

Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase

Line 2.2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW at Peak)

Company Owned Renewables

Renewable Resources shown in line item 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports, and Van Horn

VI. IDENTIFICATION OF RESOURCE OPTIONS (EXISTING CHARACTERISTICS AND INTERACTIONS)

A. Supply Side Resources

The Planning Process included a variety of resource options that are described within this section. Supply side resources modeled in this 2021 IRP includes: Solar PV, Wind, Biomass, Geothermal, Battery, and Gas Peaker. Gas-fired combustion turbines are assumed to be Hydrogen fuel capable. Given EPE's existing resource portfolio and clean energy targets, no coal generation and/or new nuclear generation was modeled. Additionally, given EPE's geographical location, hydro resources were also not considered in this IRP. The input assumptions for resource options are given in Appendix A with sources for the Technology Cost, Financing, and Transmission given in Appendix B.

1. Solar Photovoltaic Resource Option

EPE included utility scale solar PV resource option for model analysis. The amount of solar PV option that was selected by the model was based on minimizing cost while achieving clean energy targets and maintaining reliability. Site specific profiles based on NREL data were utilized to model the operational characteristics of the solar resource in EPE's region. Solar PV resources are non-dispatchable and dependent on solar irradiance, which is impacted by location and weather (cloud cover, rain, and/or overcast conditions). These characteristics of solar PV create variability in the electric utility system. This variability requires additional consideration when planning and integrating this type of resource. If a resource has an output that is variable, then contribution at peak, and firm backup capacity must be considered to plan for system reliability.

2. Wind Resource Options

EPE utilized an hourly generation profile from National Renewable Energy Laboratory ("NREL") to model the operational characteristics of a wind resource in EPE's region. Wind, like solar PV, is also a variable resource that can be impacted by weather conditions. Wind resources also require consideration for their contribution toward reliability requirements given this variability.

3. Biomass Resource

A Biomass resource burns renewable waste (solid waste and/or landfill gas) to generate electricity in a combustion turbine or reciprocating engine. This type of resource is considered a base-load resource, usually with a high-capacity factor. Generally, biomass resources are dispatchable and typically not subject to much variability. Resources with these types of characteristics are easier to integrate into the electric utility system because their generation is firm, predictable, and dispatchable. For the 2021 IRP EPE modeled a generic Biomass resource.

4. Geothermal Resource Option

Geothermal energy is a renewable resource type that uses heat from the Earth to generate electricity. A geothermal resource is generally considered a base-load resource with a high-capacity factor. However, geothermal resources can be dispatchable. EPE modeled a generic geothermal resource for this IRP.

5. Gas- Fired Thermal Power Plant Option

Gas-Fired Thermal power plants have had widespread use since the 1940s. Gas-Fired Thermal power plants can include: Combustion Turbine ("CT"), Combined Cycle ("CC"), and Reciprocating Engine ("Recip") type power plants. Modern Gas-Fired power plants have advanced due to technology improvements resulting in lower capital cost, enhanced efficiency, lower water usage, and added capability to convert to hydrogen fuel to meet future statutory zero carbon goals and to provide firm dispatchable capacity. Also, modern CTs' and Recips' have flexible fast start ramping capabilities which increases the flexibility and resilience of the electrical system needed for greater integration of renewable resources. For this 2021 IRP, EPE modeled the CT and the Recip engine as a single generic hydrogen fuel capable Gas Peaker since both types of gas-fired units have similar characteristics for purposes of the IRP.

6. Hydrogen Fuel in Gas Turbines

As the power utility sector shifts toward decarbonization, utilizing hydrogen fuel in gas turbines has become a potential option for utilities. Most gas turbines burn natural gas or methane to release energy which ultimately produces the electricity we use at home and for industry. An advantage of gas turbines is that they can operate on many other fuels besides natural gas. Some of these fuels, such as hydrogen, do not contain carbon in the first place, and will therefore not emit carbon dioxide when combusted. Furthermore, hydrogen can be introduced to new gas turbines and existing gas turbines alike, reinforcing the concept that solutions are available today to decarbonize assets already in the field and those waiting to be installed. Natural gas turbines can be fully converted or partially converted to utilize hydrogen as a fuel. Using 100% hydrogen fuel for a gas turbine will lead to a significant reduction in carbon dioxide emissions relative to operation on natural gas or other hydrocarbon fuels. As a near-term alternative, partial conversions are being considered rather than using 100% hydrogen fuel. For example, hydrogen blending with natural gas is being considered to reduce carbon dioxide emissions. In the case of hydrogen blending, the amount of carbon dioxide reduction will be a function of the percentage of hydrogen in the fuel.

Although hydrogen is a promising fuel alternative to reduce carbon dioxide, it is currently not the preferred choice for many utilities since needed storage and transportation infrastructure for the hydrogen fuel is not yet widely available. Furthermore, electrolysis and steam reforming from natural gas, which are the two main processes of hydrogen extraction, are relatively expensive and not yet cost effective. For purposes of this IRP, green hydrogen was assumed for the modeling. Another reason why hydrogen is not widely used today is due to its storage complications. Since hydrogen has a lower density, it must be compressed and stored at lower temperatures to guarantee its effectiveness and efficiency as an energy source. From a safety perspective, hydrogen gas at high concentrations is highly flammable and volatile and requires equipment upgrades to minimize risk.

B. Energy Storage

BATTERY RESOURCE OPTION

Energy Storage, specifically Lithium-Ion Battery Storage, is an accredited energy storage technology that allows for greater integration of renewable resources. Battery storage offers many benefits that complement renewable resources as well as load shifting or load following during peak hours. However, it is important to note that the round-trip efficiencies of batteries may be between 80 to 85 percent. Batteries are dispatchable and offer capacity that is very similar to traditional peaking units when dispatched to meet daily peak loads. These characteristics complement renewables like solar and wind, by charging during low load hours and firming up capacity during peak conditions offsetting the inherent variable and intermittent characteristics of renewable resources. The capital cost of batteries has continued to trend downward as technology and production has improved.

Several inherent characteristics of this technology are important when considering Battery Storage as a resource. First, battery nameplate capacity, MW, is the maximum amount of power the battery can discharge at a given moment. Secondly, battery duration is the length of time (typically in hours) that the storage system can provide output to the electrical grid system. Lastly, energy capacity, MWh, is the total amount of energy the battery can store and is typically the nameplate capacity times the hours of duration. For example, a 50 MW nameplate battery with a four-hour duration would have a total energy level available for dispatch of 200 MWh. The Battery Storage resource modeled in the 2021 IRP is a four-hour battery.

As battery costs continue to decrease, they will become a more viable resource option in expansion planning and will be further incorporated into future optimal resource portfolios, specifically due to their interaction with renewables and load shifting.

C. Demand Side Resources

ENERGY EFFICIENCY RESOURCE OPTION

In addition to EPE's current EE–programs, EPE opted to model a high EE case without identifying specific programs, but rather to assess portfolio impact. For the reference case, EPE modeled 6.5% of native system load in 2040 based on the EPE 2021 Energy and Demand Forecast. For the high EE sensitivity case, EPE doubled the incremental amount from the reference case resulting in 13% of native system load in 2040. These amounts are consistent with neighboring utility Arizona Public Service ("APS") 2020 IRP filing which includes approximately 15% EE on an energy basis.

DEMAND RESPONSE RESOURCE OPTION

EPE also includes Load Management ("LM") Programs as a resource option. When considering LM as a resource, it is important to understand that events are limited and subject to customer acceptance. When a LM event is called, customers have the choice to allow for the interruption or to opt out. If customers decide to opt out, the resource's contribution to peak will be limited. Furthermore, if a LM event were to last multiple hours, customers who did not opt out may start using energy before the event ends, which would increase system load.

EPE reviewed the EPE 2019 Residential Appliance Saturation Survey ("RASS") for viable Demand Response programs based on appliance saturation rates and on benchmarking of neighboring utilities. EPE identified the Smart Thermostat Program as the option with greatest potential with a Refrigerated Air saturation rate of 50.9% within the EPE territory. For 2021 IRP, EPE modeled 50MW by 2040 for the reference case and 60 MW by 2040 for the high DR sensitivity case. These DR amounts are comparable to the regional utility, PNM, which in a 2017 potential study found that demand response potential in the range of 60 MW to 80 MW was available, (PNM 2017-2036 IRP Plan).

To identify future DSM programs, EPE is planning to work with a third party to conduct a Potential study as a follow up to the 2021 IRP. EPE will be looking to include the following three elements in the study:

- Potential – How much DSM is there within the EPE territory?
- Economic – What is economically feasible?
- Achievable- Given real world conditions, how much is achievable?

RATES AND TARIFFS THAT INCORPORATE LOAD MANAGEMENT CONCEPTS

17.7.3.9.F(3) NMAC requires that EPE describe in its Plan "existing rates and tariffs that incorporate load management or load shifting concepts" as well as "how changes in the rate design might assist in meeting, delaying or avoiding the need for new capacity". This section includes the information required by the Rule for EPE's service territory generally, with more specific information included where rate and rate structure differences exist across jurisdictions. EPE also addresses evaluation of the impact of rate design on peak demand and energy consumption reflected in EPE's load forecast. EPE attempts to provide rates and rate structures consistently across its entire jurisdiction, especially as those rates and rate structures are intended to provide pricing and options designed to enable and incentivize economic decisions by customers with implications for the entire EPE system.

EPE's base rates are designed to recover the cost of providing electric service, including generation, transmission and distribution costs and associated O&M expenses; general and administrative expenses; depreciation expense; taxes and an allowed rate of return on rate base. In New Mexico, fuel and purchased power costs are recovered through a Fuel and Purchased Power Cost Adjustment Clause monthly, in accordance with 17.9.550 NMAC requirements. In Texas, fuel costs are recovered through a Fixed Fuel Factor in accordance with regulatory requirements. EPE's approved tariff schedules offer options to customers, including time-of-day ("TOD") alternatives that provide pricing intended to communicate differentials in the cost of providing electric service and to encourage customers to shift energy use to off-peak periods. These pricing differentials reflect, to the extent practical and contingent on regulatory approval, the differences in cost associated with serving load at different times of the year (seasonal) and day.

Advanced Metering Initiatives (AMI) and Customer Options

System-wide advanced metering enables the maximum availability of pricing options and customer programs designed to provide benefits to customers and the overall system. For purposes of this discussion system-wide "advanced metering" means retail metering capable of providing interval metering data accessible to EPE for analysis and billing purposes on at least a monthly basis, and the data processing systems capable of managing the data and computing bills under complicated pricing programs. Implicit in this definition is EPE's ability to access and process data on an accelerated basis; from acquiring the data from meters, communicating that data to databases, and accessing the data for analysis and billing purposes. On April 19, 2021, EPE filed its Automated Metering System ("AMS") plan in Texas Docket No. 52040-*Application of El Paso Electric Company for Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.* EPE plans to file its grid modernization plan this year that will include EPE's AMS for New Mexico.

<u>Rate Structures Incorporating Load Management or Load Shifting Concepts</u>

New Mexico rate structures are described as follows:

Seasonal Rates – Rate differentials between summer and winter usage are provided for all non-lighting rates. These seasonal differentials were designed to incentivize energy efficiency and conservation during the summer peak season.

TOD Rates – In EPE's most recent rate case, Case No. 20-00104-UT, EPE proposed expanding the number of classes with available TOD rate options. Rate classes with a TOD rate options are the Residential Service, Small General Service, General Service, Irrigation Service, City County Service, and Water, Sewage and Storm Sewage Pumping Service Rates. The standard Large Power Service, Military Research & Development and State University Service rates are TOD rates. Additionally, TOD rates are mandatory for new customers requesting service under; (1) Water, Sewage and Storm Sewage Pumping Service class; and (2) the General Service class if a customer's maximum demand is expected to be 400 kW or greater. TOD rates contain price differentials between kWh during on peak and off-peak hours to send more accurate price signals by reflecting cost of service differences during specific peak hours. TOD price differentials were designed to enable and incentivize consumption changes. This type of rate requires more sophisticated metering for most customers. Changes in peak use by all customers, but particularly larger commercial, industrial and irrigation customers, may reduce purchased power costs and/or delay additional generation resources.

Interruptible Rates – EPE offers a Noticed Interruptible Rate option for large commercial, industrial, and institutional customers. Unlike the other options described above, the Noticed Interruptible program provides for additional system capacity on an emergency basis only. EPE has implemented a load management option for residential and large commercial customers through its EE/LM programs, which is discussed in more detail above.

EPE's current rates were implemented pursuant to the Final Order in NMPRC Case No. 20-00104-UT in New Mexico and Docket No. 48631 in Texas. The rates and rate differentials contained in the current rate structures are intended to incentivize energy efficiency, energy conservation and load shifting by customers. Price differentials reflected in rates are established consistent with the cost of associated services; generally, production-related costs. For example, peak period (e.g., on-peak energy) pricing differentials are based on the cost of peak generation production costs. The price signals specifically target the afternoon hours of the summer months, when EPE's system peaks. These higher prices during on-peak periods incentivize increased utilization of energy efficiency and conservation measures and/or increased load shifting, either through demand side management projects, i.e., automated controls, thermal energy storage, or through customers changing the operational hours of their equipment. This in turn works to decrease EPE's summer peak, which can help reduce the need for or delay new capacity resource additions.

Customer and System Benefits

TOD and other variable pricing and dynamic pricing options provide customers the opportunity to impact their monthly bill by modifying energy consumption in response to price differentials. In the simplest case, this means adjusting usage (energy consumption) during different times of the day, by either reducing consumption or shifting usage to a lower-priced period. The extent to which a customer may benefit is a function of the price of energy in the standard offering, the price differentials offered in the optional pricing structure and the customer's ability to manage their energy consumption. A marginally higher on-peak price, for example, provides a greater incentive to reduce consumption than the lower standard price for consumption in the same period. Likewise, a shifting of consumption from high price to low-price periods is incentivized by the price differential by providing a benefit not available under a level price standard rate. Dynamic pricing options, which can be constructed as overlays to either a standard or TOD pricing option, can increase customer benefit.

Another fundamental variable in the ability of price response rates to impact customer usage and system load profile is whether the rate structures are voluntary or mandatory. Customer "opt-in" performance, where customers make an affirmative decision to participate in a voluntary pricing program with both potential risk and benefit is typically low, and utility efforts to generate customer participation constitute an additional cost for programs. Generally, speaking, voluntary participation programs consist largely of functional benefiters – customers receiving rate benefit due to the nature of their usage profile with little or no change in their consumption characteristics. Conversely, mandatory TOD rate structures, such as EPE currently provides for its largest commercial and industrial customers have

100% participation rates, with resulting customer and system benefits a function of the ability of customers to adjust their usage profiles over the long-term.

Dynamic pricing programs generally overlay standard or voluntary pricing options. Critical Peak Pricing ("CPP"), Peak Time Rebate ("PTR") and Capacity Bidding are examples of dynamic pricing programs which can overlay mandatory rate structures and require advanced metering capability. All are callable programs which can be initiated on day-ahead or even day-of notice to achieve demand reductions during peak periods. Dynamic pricing as an overlay to a TOD pricing option offers EPE the ability to offer additional savings, based on a near-term need for resources, over and above what can be achieved through peak rate differentials. For example, a PTR option can provide incremental reductions in on-peak usage already reduced in response to TOD pricing differentials, which benefits both the participating customer and the utility.

EPE's 20-Year Rate Initiative

The EPE system load profile is one cost-driver of overall rate levels. The system profile in turn is impacted in the long-term by both permanent changes in customer consumption and short-term response to rate differentials. Permanent changes in customer usage profiles result from long-term exposure to predictable price differentials and are most directly impacted by mandatory rate structures. Residential, commercial, and industrial customers require time to adjust their usage characteristics in response to pricing differentials, and pricing differentials based on cost of service generally change slowly. Dynamic pricing options in contrast are intended as short-term resource options for the utility. The combination of the two pricing approaches can, over the long-term, impact the system profile sufficient to impact resource planning.

Table 16 below shows a long-term plan for rate structure development focused on providing customers increasing levels of price information and menu of rate options and designed to provide customers the opportunity to benefit from changes in their usage characteristics.

Table 16. Rate Structure Development

	Current	3-Year	5-Year	10-Year	20-Year
Residential	Energy	Energy	Energy / CPP & PTR	Energy / CPP & PTR	TOD Energy / CPP & PTR
Small Commercial	Demand / Energy	Demand / Energy	Demand / Energy CPP & PTR	Demand / TOD Energy CPP & PTR	Demand / TOD Energy CPP & PTR
Medium Commercial	Demand / Energy	Demand / TOD Energy	Demand / TOD Energy CPP & PTR	Demand / TOD Energy CPP & PTR	Demand / TOD Energy CPP & PTR
Industrial and Military	Demand / TOD Energy	Demand / TOD Energy	TOD Demand / TOD Energy	TOD Demand / TOD Energy Capacity Bidding	TOD Demand / TOD Energy Capacity Bidding
Irrigation and Pumping	Demand / TOD Energy	Demand / TOD Energy	Demand / TOD Energy	Demand / TOD Energy	Demand / TOD Energy

The solid black line indicates the point at which the mandatory rate structure for the class would include TOD energy charges (the TOD line). Generally, large industrial, military, and irrigation and pumping customers already have mandatory TOD pricing tariffs. The vertical double-line indicates approximate timing for completion of a system-wide Advanced Metering Initiative ("AMI"). Because of the number of customer accounts represented by the Residential and Small Commercial classes, advanced metering on a system-wide basis is critical to the success of expanding TOD and dynamic pricing options.

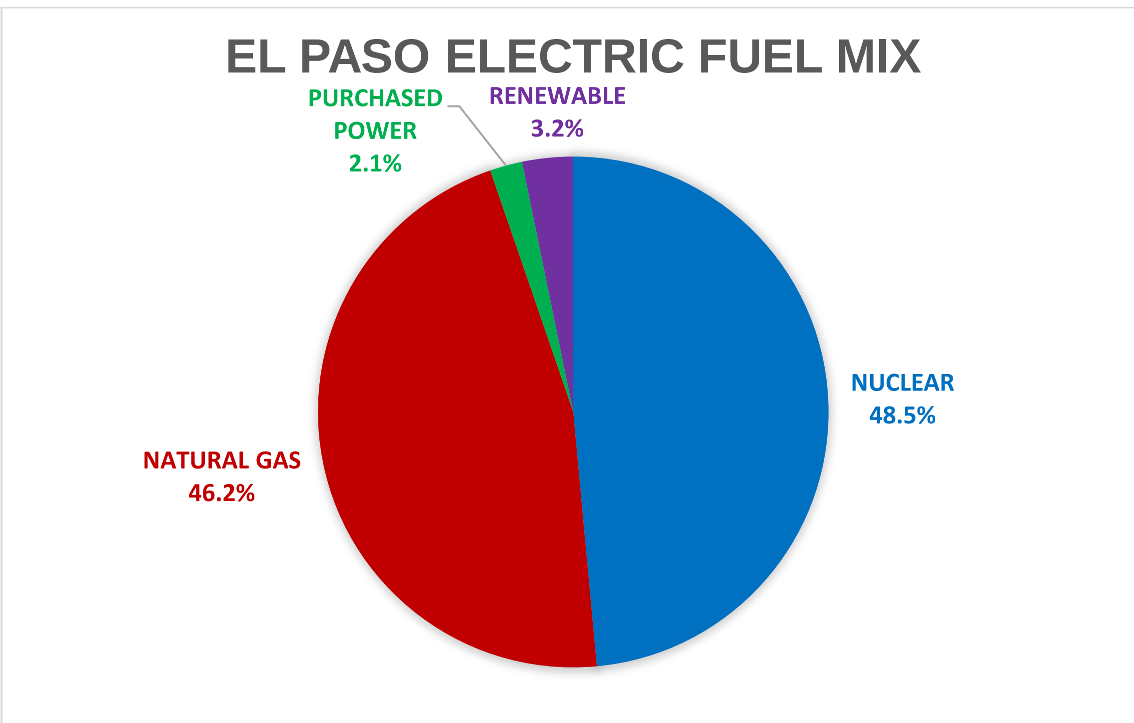
EPE's assessment of the impact of rate differentials and rate structures is that the net effect of rate structures changes, participation rates driven by mandatory requirements, and dynamic pricing following AMI implementation would not exceed the lower band confidence interval of future native system demand and energy (Figures 9 and 10). Long-term rate and rate structure changes can have an impact on customer demand and average use per customer, but these effects can likewise be offset by increased penetration of technologies such as electric vehicles. EPE's assessment is that the rate impacts discussed here, assuming all other things equal, will have the effect of reducing the slope of demand and energy growth over time. In addition, by establishing rate differentials and dynamic pricing programs based on the cost of peak generation resources, the cost-effectiveness of these rate offerings is comparable to avoided cost of the relevant resource alternative.

VII. DESCRIPTION OF THE RESOURCE AND FUEL DIVERSITY

EPE primarily meets its customers' electrical demands with power generated from its generating stations, which are powered by natural gas and uranium. Utilizing renewable resources, particularly solar, as part of its system, EPE increases its fuel resource diversity. While EPE no longer has the coal-fired FCPP in its resource fleet, EPE is still able to maintain a diverse resource mix of nuclear, gas-fired, renewables, and purchased power.

EPE's energy mix for 2020, the most recently completed calendar year, is based on MWh generation as shown in Figure 12.

Figure 12. EPE 2020 Energy Fuel Mix



VIII. IDENTIFICATION OF CRITICAL FACILITIES SUSCEPTIBLE TO SUPPLY-SOURCE OR OTHER FAILURES

EPE's current critical facilities that are susceptible to supply-source or similar failures include its natural gas fired generation plants. These facilities are susceptible to supply-source failures due to the fuel required for unit operation and the resulting power generation. If the natural gas supply-source was to experience a large-scale failure, then some of EPE's critical facilities could be impacted. To mitigate some of this risk, EPE periodically reviews its natural gas transportation and storage capability and any local fuel related concerns. EPE is connected to two major gas pipelines (each with multiple large lines entering the city) on the interstate and on the intrastate system. EPE also has emergency on-site fuel oil backup capability at its local Montana Power Station. This multiple gas pipeline configuration, as well as purchased power availability as transmission constraints permits, fuel oil backup, and EPE's ability to activate the HVDC Eddy Tie, which is interconnected to the SPP, would contribute to EPE's ability to mitigate local fuel and service requirements given a supply-source failure at a critical facility. In addition, EPE has nuclear units that would not be impacted by a gas pipeline outage.

EPE's existing solar resources are also susceptible to "supply disruptions" given their dependency on solar irradiance. EPE's existing solar nameplate capacity of 115 MW (including the 5 MW Holloman project) does not present an energy supply risk. However, consideration would need to be given for additional amounts of solar and wind, see Section IX.

IX. DETERMINATION OF THE MOST COST-EFFECTIVE RESOURCE PORTFOLIO AND ALTERNATIVE PORTFOLIOS

A. Transmission Constraints for Most Cost-Effective resource Portfolio

Transmission considerations are an essential part of the task of identifying a cost-effective resource portfolio, especially when considering resources located beyond the areas in which EPE's load resides. First, it is important to identify the potential for EPE to import resources that can reach EPE's load. As documented in EPE's prior IRPs, available wind resource options are located in specific geographical areas. Such areas are not within the central core where the bulk of EPE's load resides. The same is true for potentially available geothermal resource options. Solar on the other hand, is somewhat different. EPE has identified a significant amount of potentially available solar resource capacity near the fringes of where the bulk of EPE's load resides on its system. Anticipated solar facilities in the capacities being considered as potentially available for future portfolios are expected to be located on the periphery of EPE's Las Cruces and El Paso load pockets. With respect to battery storage as well as gas generation resources, these types of resources are potentially available near to EPE's load. They tend to require less land and may be more readily sited closer to load. The central load pocket and peripheral areas to the local system are shown in Figure 13.

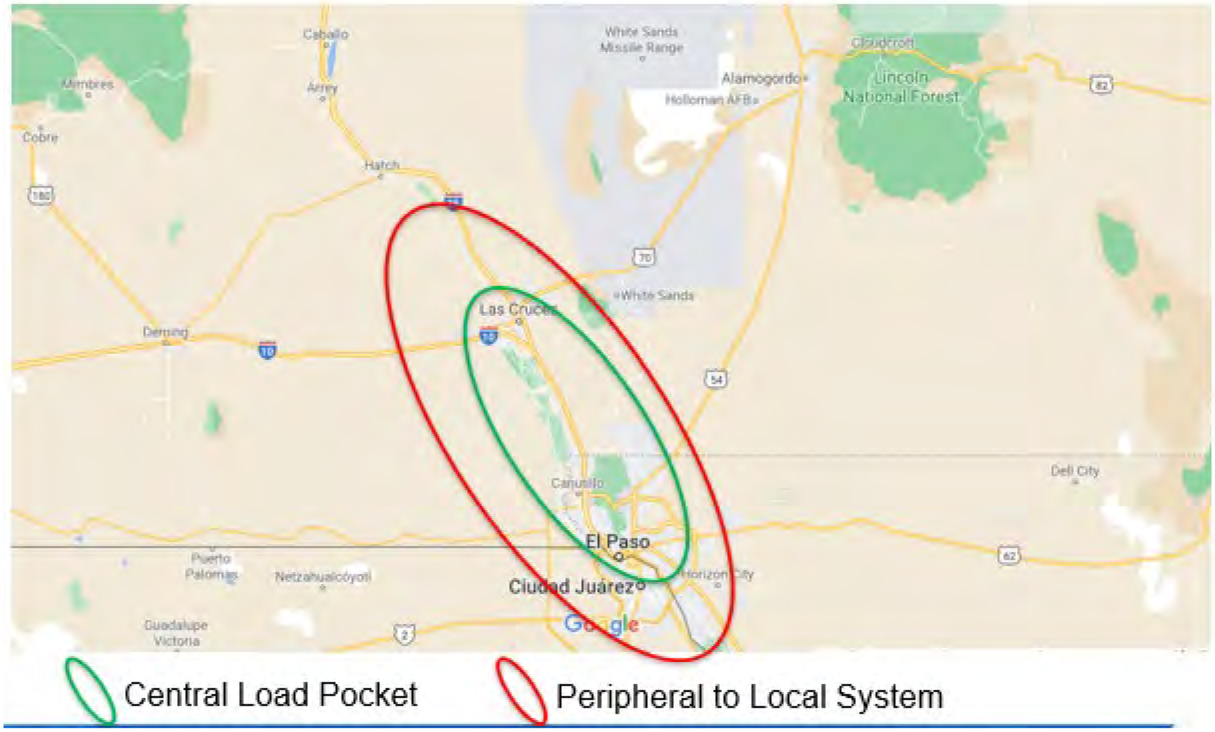


Figure 13. EPE Local and Peripheral Areas for New Renewable Resources

EPE utilized NREL renewable resource potential maps to identify geographical sites closest to EPE's system for potential wind and geothermal resources. The approximate location of the geographical sites was previously shown in Figure 1 above and for proper context, is shown here again as Figure 14. Transmission upgrade costs between the resource locations and EPE's load pockets were then considered as costs associated with those resource options.

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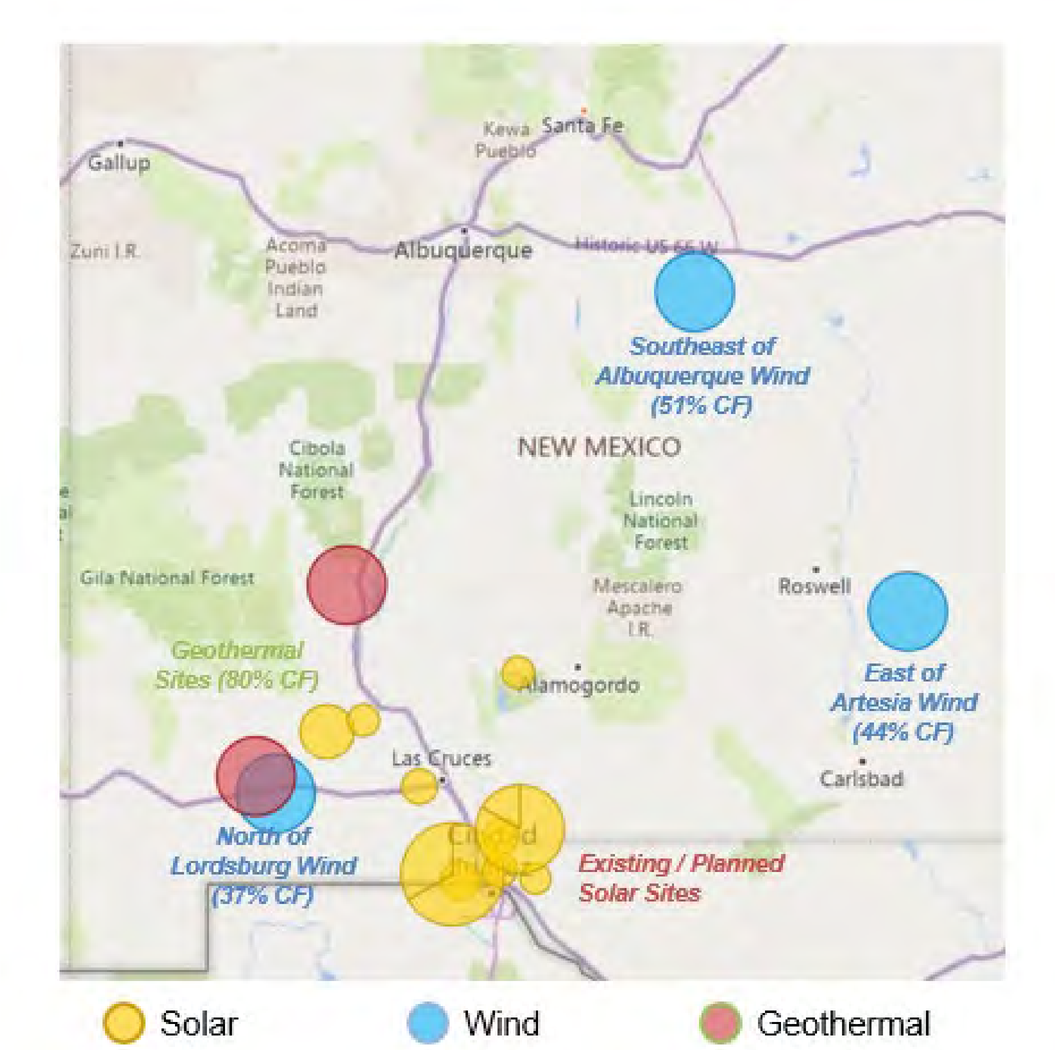
Figure 14. EPE Renewable Resource Geographical Locations



Second, it is important to consider the impact on reliability of displacement of gas generation on its system by increased inverter-based renewable and storage resource options. EPE has evaluated and identified, for year 2030 and year 2038, system reliability impacts on EPE's service territory that would result from increased integration of renewable resources on EPE's system. Increased renewable generation was assumed to partially replace existing EPE-owned thermal generation as a percentage of EPE's overall resource mix. The assessment included steady state and transient stability analyses under various generation dispatch scenarios minimizing the dispatch of gas resources to identify voltage constraints and system stability after faulted conditions and line contingencies. EPE also conducted a short circuit ratio (SCR) analysis to identify the potential that breakers would exceed their duties resulting from the displacement of gas generation by increased integration of inverter-based and storage resource options on EPE's system. The analyses included steady state, transient stability, and reactive margin (V-Q) analyses to identify potential criteria violations for pre- and post-contingency conditions.

EPE's evaluation produced the following observations:

- Voltage stability was an issue. Voltage exceedances occurred on the higher voltage transmission lines in EPE's service territory in study year 2030, as well as in study year 2038. It is likely that reactive support devices, such as static VAR compensators (SVCs), static compensators (STATCOMs), synchronous condensers, and/or additional local generation could address this issue in study year 2030. Such measures, alone, are not expected to be able to fully remedy this issue in study year 2038.

- EPE's load is likely to experience greater load shedding during multiple contingencies. This is especially so in study year 2038. With the reduction in thermal generation (and a corresponding increase in renewable generation), there is a reduction in the level of dynamic voltage support that thermal generation would have provided. With less dynamic voltage support available, the risk of system instability increases. Load shedding is a way to mitigate the risk of system instability. While most of EPE's area can accommodate significant inverter-based resources (IBRs) for the 2038 study year (relying on activation of EPE's Under Voltage Load Shed (UVLS) program when necessary to maintain reliability when dynamic voltage support is insufficient), investment in transmission infrastructure may be necessary to mitigate this reliability risk on a long-term basis so that the EPE system can accommodate the projected growth in its load without substantial increases in the frequency and scope of load shedding events. The type and scope of effective mitigation in the form of transmission infrastructure will be dependent in part to the Western System Coordinating Council's ("WECC") system evolution. EPE's preliminary analysis was based on the WECC's current system and showed a system encroaching on threshold limitations for reliability due to short circuit. It is recommended that an assessment be performed every three years to capture WECC's system transformation from gas and coal units to inverter-based generation, and the impact this will have on inertia and short circuit. The reduction in turbine-based (thermal) generation will certainly impact EPE's short circuit capability beyond 2030; this is an area requiring continued evaluation.

Key Takeaways:

- The 2030 New Mexico REA requirement of 50 percent renewable is likely attainable on the EPE system with the implementation of additional known technologies such as SVCs, STATCOMs, and/or synchronous condensers.
- Additional technical solutions, including under-voltage load shedding and transmission infrastructure, could be pursued to address the system conditions that would arise under the 2040 New Mexico REA requirement of 80 percent renewable requirement.
- Attaining the 2045 goal of 100 percent carbon free resources (given known technology evolution through the next twenty years) is expected to require the utilization of combustion turbines (either gas or hydrogen fueled). Hydrogen fueled combustion turbines would be carbon free and their consideration is discussed further later in this report. Others in the industry are making similar observations on the continued role of combustion turbines in electric grid operations. One such example is the NREL study for Los Angeles attaining 100 percent carbon free requires combustion turbines with hydrogen fuel or renewable biofuels.[6]

B. Resource Adequacy and Resulting Reserve Margin

Due to the changing characteristics of a resource portfolio which will continue to integrate greater amounts of variable energy resources and storage capacity with finite capacity, EPE reassessed its resource adequacy as part of this IRP process with support from E3.

To do so, E3 evaluated EPE's resource adequacy needs via its RECAP modeling software evaluating resource adequacy across the full year. The RECAP model assesses the loss of load expectation ("LOLE") based on the statistical variability of load, variable energy resource availability, and the forced outages of all resources and import transmission lines. The RECAP model quantifies the availability of resources in terms of Effective Load Carrying Capability ("ELCC") which is representative of that resource's contribution to reliably serving load. The ELCC accounts for the statistical probability for the availability of a resource to serve load and addresses unavailability due to forced outages for all resources. Further, the ELCC accounts for variable energy resources such as solar and wind including the output variations due to weather variability. ELCC is also utilized to consider limitations for duration of storage resources and limitations for number of call events for demand side resources. The ELCC is a robust measure of a resource's contribution to a utility's reliability standard and is defined as the quantity of "perfect" capacity that could be replaced or avoided by a resource while providing equivalent system reliability. The PRM was assessed based on the Perfect Capacity ("PCAP") PRM

[6] NREL. LA100: The Los Angeles 100% Renewable Energy Study – Executive Summary. pp. 29, 34. March 2021. https://www.nrel.gov/docs/fy21osti/79444-ES.pdf

convention, which counts all resource contributions toward the RPM based on their ELCCs. The RECAP model can determine the PRM that is required to meet a specified LOLE.

EPE elected to implement a reliability target of one loss of load event every ten years (i.e., 0.1 Loss of Load Expectation, or LOLE), which is increasingly common industry practice. The "one in ten" target is a reasonable threshold given the importance of reliability expected by society, governmental agencies, and EPE's obligation to provide safe and reliable power. EPE's current PRM approximates the LOLE of 24 loss of load hours in ten years. EPE proposes to shift to the "one in 10" target over the twenty-year horizon in a phased approach. As such, for IRP years through 2029, EPE will utilize a "two in ten" LOLE target and will augment its PRM by maintaining retired units in mothball status prior to fully abandoning. In 2030, EPE will shift to the "one in ten" LOLE target.

The resulting PCAP PRM through 2029 will be 10% for a 2 in 10 LOLE. The 2030 PCAP PRM will increase to 13% for a 1 in 10 LOLE. A more detailed description of the modeling and results in provided in E3's EPE Report.

EPE has considered all feasible supply, energy storage, energy efficiency, and demand-side resource options on a consistent and comparable basis to develop the optimal resource portfolio. Given the added complexities and characteristics of today's resource options, it is necessary to describe the planning analysis in detail.

Ultimately, the goal is to ensure that EPE has a portfolio that reliably meets both the peak and energy demands of our customers. Given this goal, it is necessary to analyze what combination of resources, given their respective characteristics, can optimally serve load.

RECAP Model

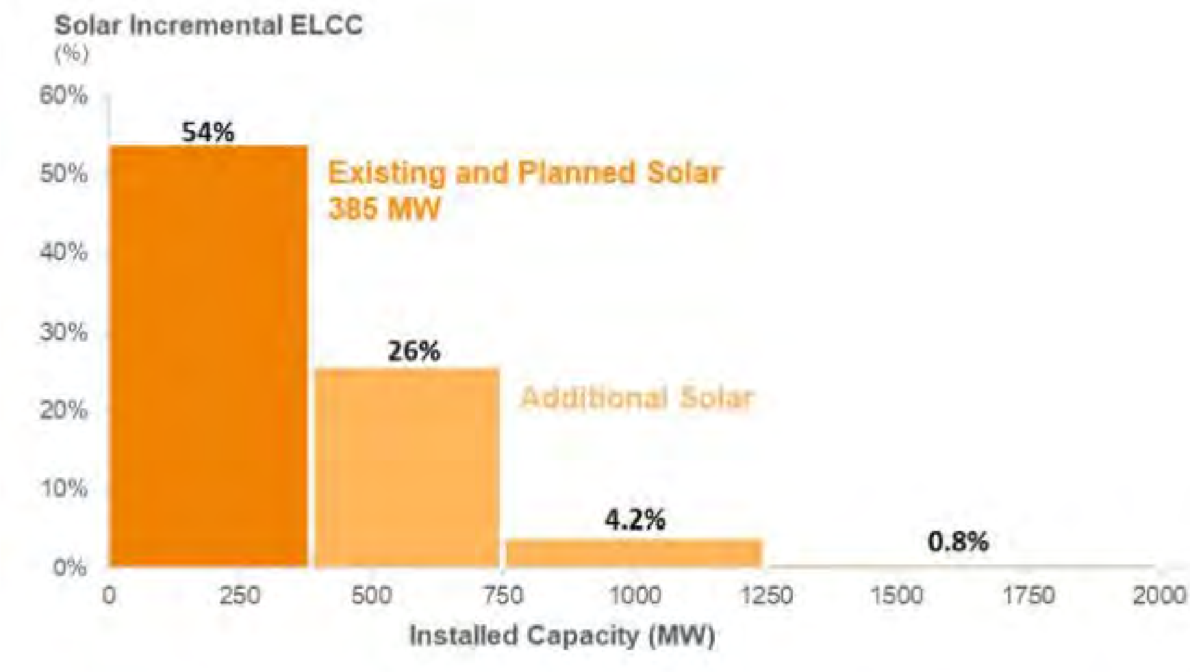
The first step in the resource planning process is to quantify the ELCC values for each resource type. This is necessary because as mentioned above, resources differ in their availability to serve load at different times of the day and year. Solar photovoltaic resources are only available during daytime hours. Wind resources have higher output profiles during nighttime hours and vary throughout the year. Geothermal resources also have seasonal output profiles that must be considered. Similarly, battery storage facilities have limited availability specific to their energy storage capacity. All resources, including gas and nuclear resources have unexpected, forced outage rates. As described earlier in the report and as described further in E3's EPE Report, RECAP utilizes statistical analysis to estimate ELCC values for the different resource types. The E3 report describes further the unique characteristics of the resource types and how the RECAP model assesses their contribution to serving load. Before describing the unique characteristics of the various resource types, it is re-iterated that the RECAP analysis considers forced outage rates for all types of resource types including gas generation and nuclear generation. Following is a brief description of key characteristics of the various resources.

Solar Resources

Solar power output has two main sources of variation: Diurnal: Solar energy is generated only when the sun is shining in the daytime and none is generated at night. Intermittent: Solar energy can be significantly reduced during substantial cloud cover or other weather-related events. This source of variation is called intermittency. The risk is accentuated during times of system peak, as EPE's reserve margins are tightest at peak hours. Prior to 2018, EPE had determined that at its system peak, its existing solar resources could be counted on to produce energy equivalent to approximately 70% of its nameplate capacity rating to meet that peak. This energy at peak percentage (70% in this case) is also known as the capacity credit. In large measure, EPE's historic 70% capacity credit was a function of the small amount of solar power EPE had on its system and the simplified approximation study that EPE performed to calculate the credit. In EPE's 2018 IRP as EPE planned to increase the amount of solar resources, it was necessary to consider the added variability risk and solar contribution to peak. In EPE's 2018, EPE assigned a 25% contribution for solar up through the next 400 MW of solar capacity. This was necessary to reliably meet peak demand as described in the following paragraphs. In the 2021 IRP EPE is shifting to assessing contribution to serving load via the ELCC methodology with the RECAP model. RECAP can assess both the diurnal and intermittency variability by way of the ELCC value. It is important to note that the diurnal solar output patterns result in a mismatch between peak solar power generation and EPE's peak system load patterns. Typically, peak solar output occurs several hours in advance of EPE's system peak. This necessarily results in a solar capacity credit of less than 100%, as the maximum nameplate capacity of solar is not available at the time of EPE's system peak. Simply put, since solar is only available during the daytime hours, at a certain point, a utility will have sufficient solar resources to meet daytime loads. However, regardless how much more solar is added above that point, it will not help serve the nighttime loads (unless coupled with battery storage – this will be discussed further in the RESOLVE section). At this point, the contribution to peak of additional solar falls to zero since it can no longer contribute to peak reduction.

RECAP also assesses solar performance due to intermittency attributed to cloudy days or low solar irradiance days. The RECAP analysis utilizes historical solar generation data from EPE and simulated solar generation data from NREL to statistically quantify the variability. The RECAP model is then able to determine ELCC values at higher solar penetration levels. The ELCC concept is illustrated in Figure 15. Furthermore, there is a resultant cumulative ELCC for solar combined with storage which is described in more detail within the E3 report in section 5.1.3.

Figure 15. ELCC for Standalone Solar



<u>Wind Resources</u>

Wind resources also have unique characteristics. First, its output profile is less consistent and highly variable compared to solar. Wind output profiles are typically provided based on expected (average) profiles for each month. Figure 16 illustrates NREL expected monthly output profiles for wind resource regions that are closest to EPE's service territory.

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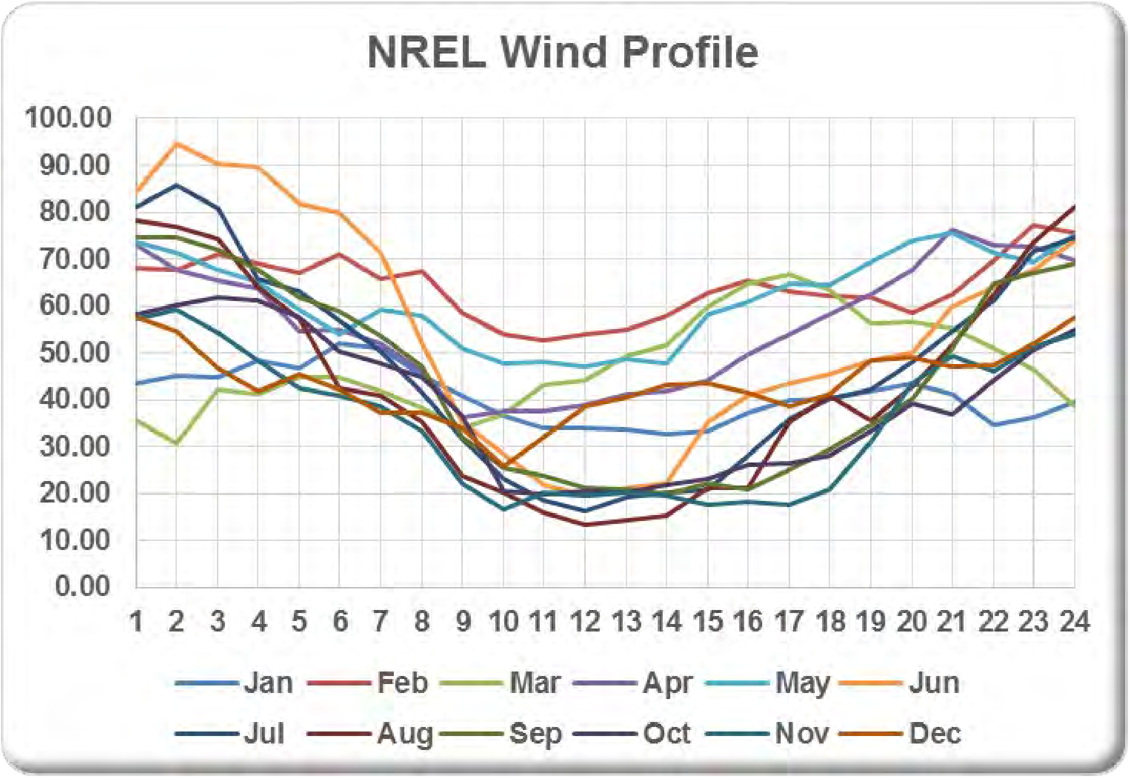
Figure 16. Monthly Wind Profiles



The present profiles demonstrate two important characteristics. First, the months of May to August, which are EPE's peak months, have the lowest average output profiles. Second, during EPE's peak hours, wind output is at their lowest. In a similar fashion to solar, the RECAP analysis utilizes simulated wind generation data from NREL to statistically quantify the seasonal and intermittency variability to assess expected ELCC values at increasing wind integration levels. Figure 17 shows the incremental ELCC values for the Wind resource.

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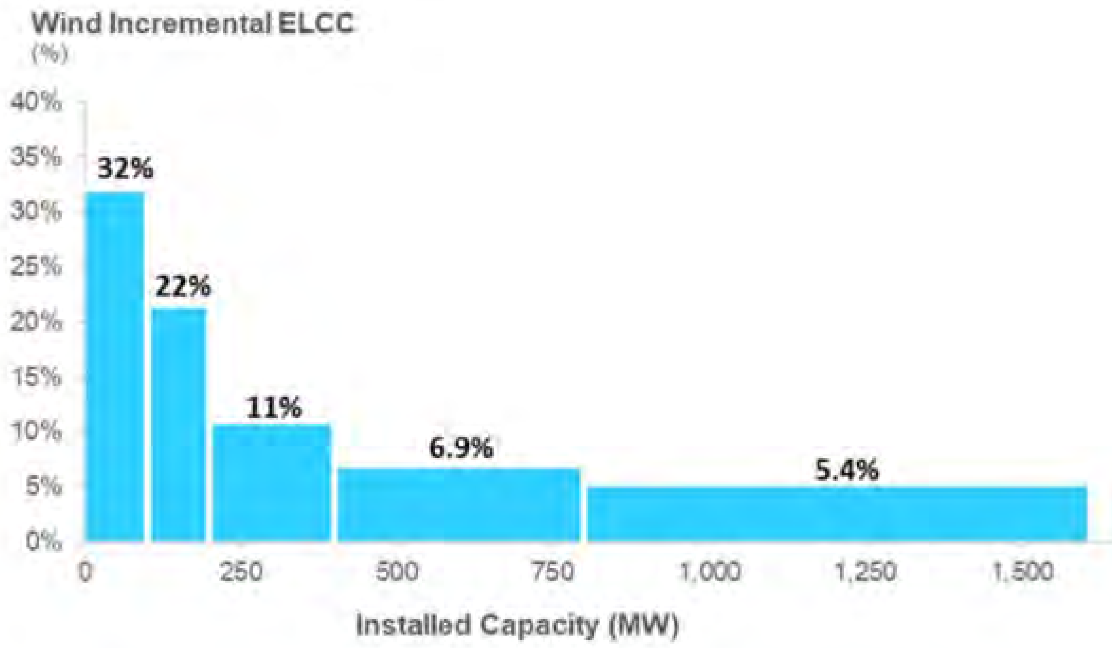
Figure 17. Incremental ELCC for Wind Resource



<u>**Geothermal Resources**</u>

Geothermal has at times been thought of as a resource available at 100% nameplate throughout the year and all of hours of the day. However, as more geothermal facilities have been constructed, it has been learned that geothermal resources also have diurnal and seasonal output patterns most likely attributed to ambient conditions. In a similar fashion, the RECAP analysis utilizes simulated generation profiles for potential geothermal resource projects to statistically quantify the diurnal and season variability to assess expected ELCC values for geothermal resources. Figure 18 shows the incremental ELCC for geothermal.

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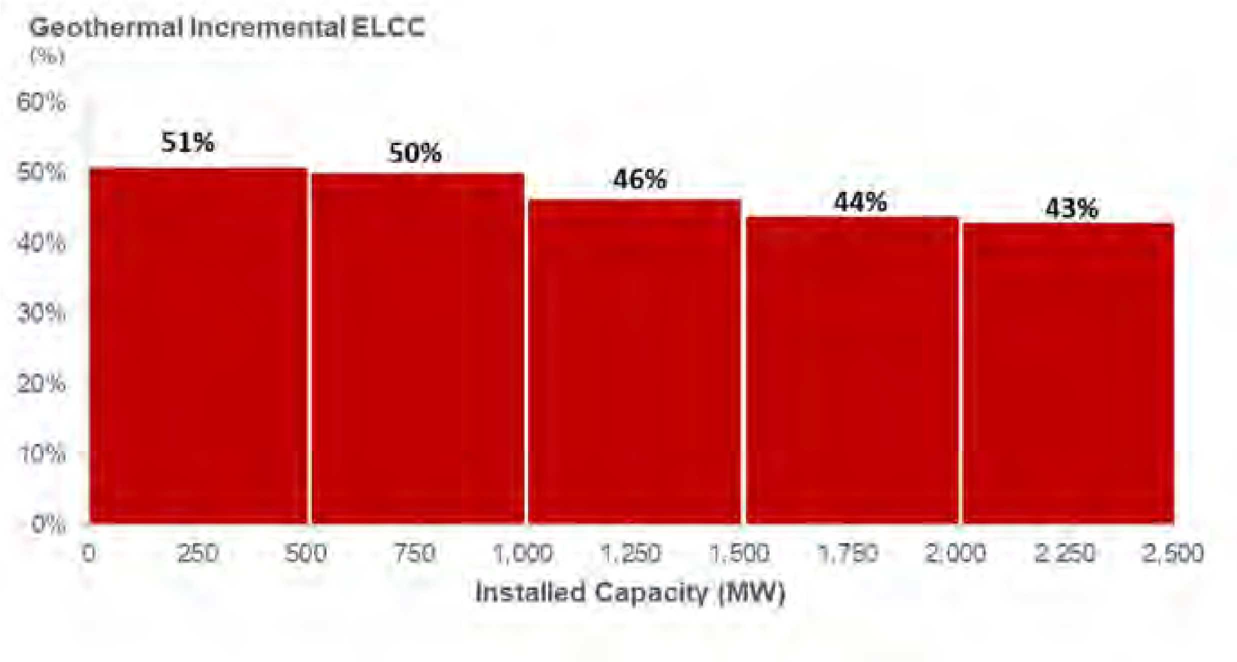
Figure 18. Incremental ELCC for Geothermal Resource



<u>Storage</u>

Storage is modeled as a four-hour duration lithium-ion battery storage system. The storage system is modeled to incorporate the 85% round-trip efficiency and furthermore evaluates the availability of a charging energy resource. Similarly, RECAP considers the benefits of coupling battery storage with solar to shift outputs and assess an ELCC value for battery storage at greater integration levels. Figure 19 shows the ELCC for standalone 4-hour energy storage.

Figure 19. Incremental ELCC for Standalone 4-hour Energy Storage

RESOLVE MODELING

RESOLVE is a capacity expansion planning model that determines the optimal integrated demand-side and supply-side portfolio for a utility system under a prescribed set of inputs and assumptions. RESOLVE is a linear program model which allows it to efficiently analyze a multitude of resource options and combination of resource options to identify the most cost-effective portfolio. This includes the ability to evaluate the combination of storage with solar and wind as well as the synergies that exist between solar and wind resources. In addition, RESOLVE can assess the impacts of various scenarios and sensitivities based on total plan costs by imposing renewable energy targets, decarbonization targets or various sensitivities to inputs such as a carbon tax or fuel cost levels. RESOLVE enables EPE to study a wide variety of long-term expansion planning resource options and their costs (described in Section VI), unit retirements, unit capacity variations, demand-side management options, fuel costs, and reliability limits to develop a coordinated integrated plan which would be best suited for the EPE system. RESOLVE simulates the operation of a utility system to determine the cost and reliability effects of adding various resources to the system or modifying the load through demand side management options. The E3 report provided in E3's EPE Report provides a more detailed description of the RESOLVE model, modeling inputs, and scenarios.

RESOLVE MODELING – PRELIMINARY DECARBONIZATION SCENARIOS

EPE initiated the RESOLVE modeling efforts by first running a range of decarbonization scenarios including up to 100 percent carbon free portfolios by 2040 utilizing the ELCC values determined by RECAP for each resource types. The two carbon free scenarios analyzed were: (1) 100 percent carbon emission reduction by 2040 with hydrogen fuel (100% H2); and (2) 100 percent carbon emission reduction by 2040 with only renewable and existing nuclear (100% No CT). Under the first carbon free scenario, all existing gas plant would be converted to hydrogen fuel and all new gas plant would be hydrogen fueled. EPE also modeled a scenario with no new combustion turbines after the 2024 operations of Newman 6 (No New CTs). The purpose of this preliminary analysis was to evaluate on a total company basis the cost of increased renewables and decarbonization up to 100 percent carbon free portfolios by 2040. This analysis provides EPE information for total system decarbonization comparable to the New Mexico RPS requirements as well as inform EPE's City of El Paso Renewable Study. These modeling scenarios were performed for EPE's full system requirements inclusive of New Mexico and Texas load requirements in the following order.

- First, the RESOLVE model was allowed to select the lowest cost portfolio with no imposed renewable energy or carbon reduction requirements to establish a baseline portfolio for the preliminary decarbonization scenarios.
- Second, both the New Mexico RPS and Texas renewable requirements[7] were imposed, and the model optimized inclusive of the state requirements.
- Then RESOLVE was utilized to run further decarbonization scenarios in 20 percent increments.

The scenarios analyzed through these three steps and the resulting carbon free and renewable percentages are denoted in Table 17 below. Significantly, as discussed below, step 1 and step 2 of this preliminary decarbonization analysis, resulted in the same least cost baseline portfolio.

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[7] Texas has a statewide goal for 10,000 mw of installed renewable generation located in Texas by 2025, with a target of 500 mw of it to be non-wind generation. The goal is to be met through a requirement for each load serving entity in the state to retire their share of Renewable Energy Credits (RECs) each year. El Paso Electric Company can obtain RECs for retirement either through producing such RECs from their own renewable generation located within Texas or purchasing them. PURA Section 39.904, Goal for Renewable Energy, and 16 Tex. Admin. Code §25.173.

Table 17. **Decarbonization Scenarios Modeled in Resolve**

PORTFOLIO NAME	PORTFOLIO DESCRIPTION	CARBON FREE (%)	RENEWABLE (%)
Lowest Cost	Meets State RPS	74	34
20%	20% Carbon Emission Reduction by 2040	79	40
40%	40% Carbon Emission Reduction by 2040	84	44
60%	60% Carbon Emission Reduction by 2040	89	49
80%	80% Carbon Emission Reduction by 2040	94	55
90%	90% Carbon Emission Reduction by 2040	97	58
100% H2	100% Carbon Emission Reduction by 2040 with Hydrogen Fuel	100	59
No New CT	No New Combustion Turbines after 2024	94	55
100% No CT	100% Carbon Emission Reduction by 2040 with Only Renewables (Existing Nuclear)	100	61

The specific scenario details are set forth in E3's EPE Report. Figure 20 shows the additional nameplate capacity in 2040 for each corresponding portfolio cost (excluding grid reliability costs) for each respective scenario analyzed.

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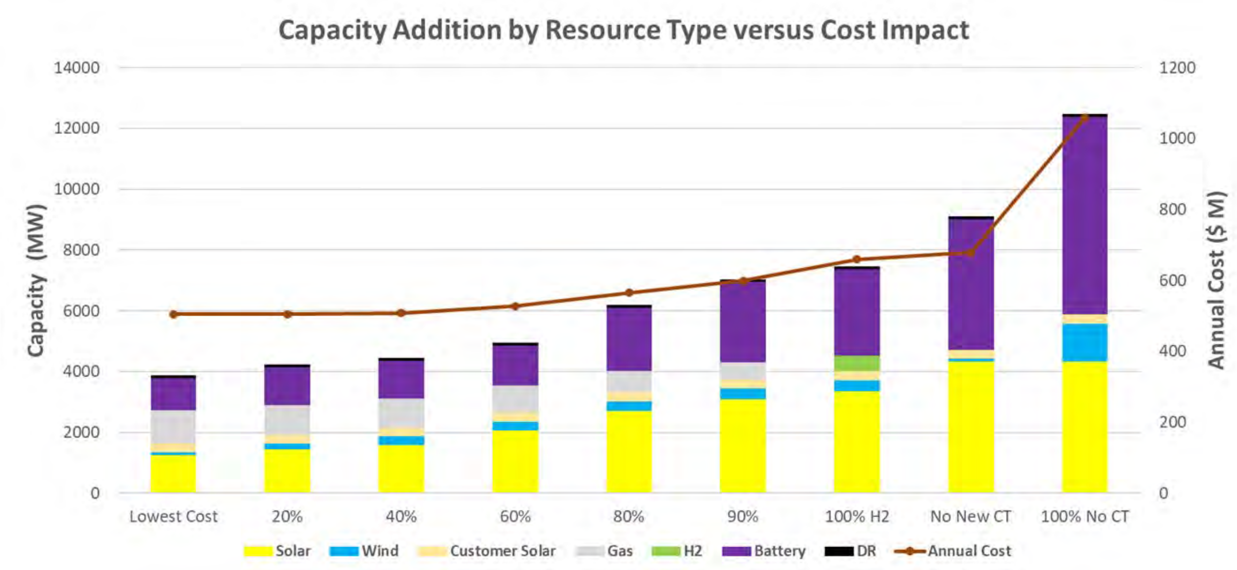
Figure 20. Capacity Addition by Resource Type with Cost Impact for 2040



As illustrated by Figure 20, increased decarbonization and renewable integration results in increased cost. More importantly, note the cost difference for the two 100 percent carbon free scenarios. The 100% No CT scenario which does not include combustion turbines, whether gas or hydrogen fueled, results in a significantly greater cost than the 100% H2 scenario. This is because significantly greater amounts of renewables and storage are required to eliminate the last 10 percent of carbon without a transition to hydrogen fueled CTs. This is an important finding in evaluating options for full decarbonization while considering customer affordability. Also, noteworthy, is the greater cost of the No New CT scenario that assumes no new combustion turbines after EPE’s Newman Unit 6 planned for 2023. These findings are consistent with similar analyses for other regions that include combustion turbines as part of the transition to decarbonization because CTs provide needed firm capacity for resource adequacy and grid reliability, even if utilized at a very low-capacity factor. The units may then transition to hydrogen fuel options as the technology evolves, which is carbon free. It is important to note that EPE has not completed a grid reliability assessment for a 100 percent carbon free portfolio without combustion turbines. EPE has assessed an 80 percent carbon free portfolio equivalent and deemed it is viable with increased transmission infrastructure upgrades. However, that preliminary study addressed above in Section IX encroaches on the limits of grid reliability. Further, EPE does not currently see the grid technology to eliminate combustion turbines completely, but further technological advancements may provide future solutions.

The graphs in Figure 21a -21b more clearly illustrate the correlation of increased cost at increased renewable integration and decarbonization. These graphs illustrate the following three important points:

1. attaining 60 to 80 percent decarbonization is possible with marginal cost increase;
2. attaining the last 10 to 20 percent decarbonization is more reasonably attainable, based on cost, with the planned use of hydrogen fueled combustion turbines; and,
3. eliminating the use of hydrogen combustion turbines greatly increases the cost of the last 10 percent decarbonization.

Figure 21a. Percent Renewable and Decarbonization for Scenarios for 2040

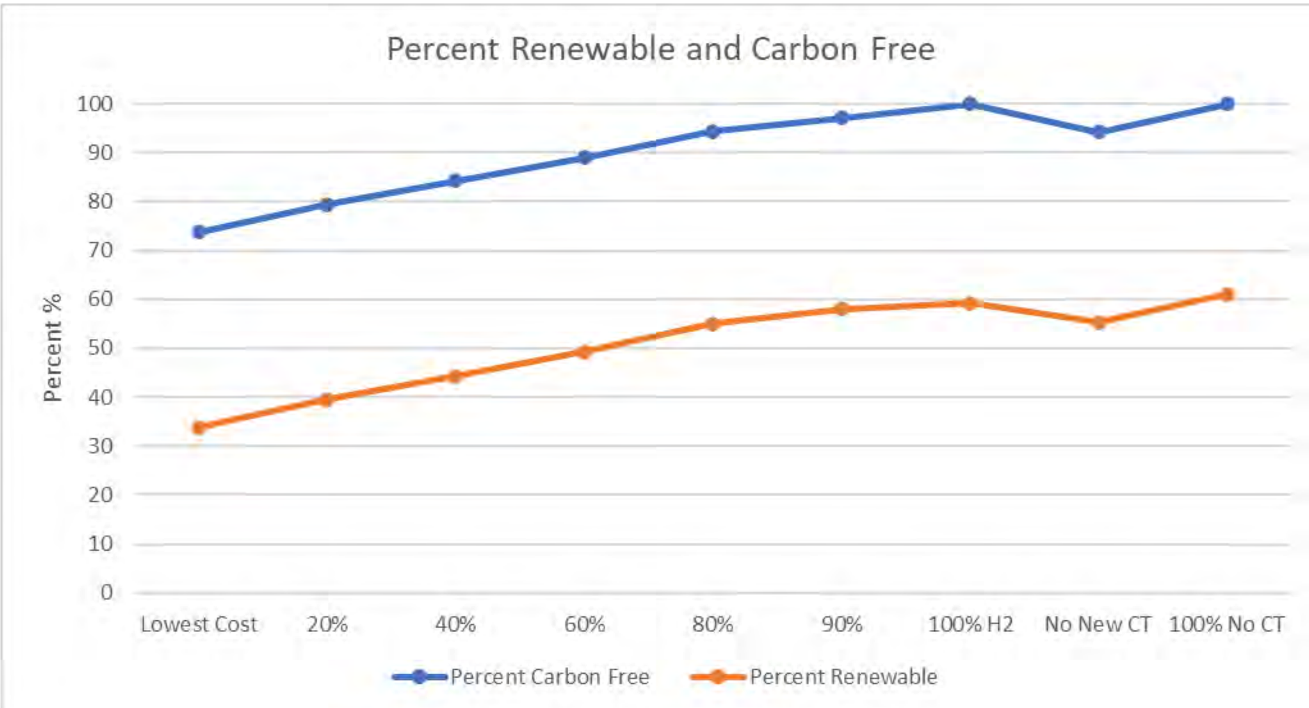
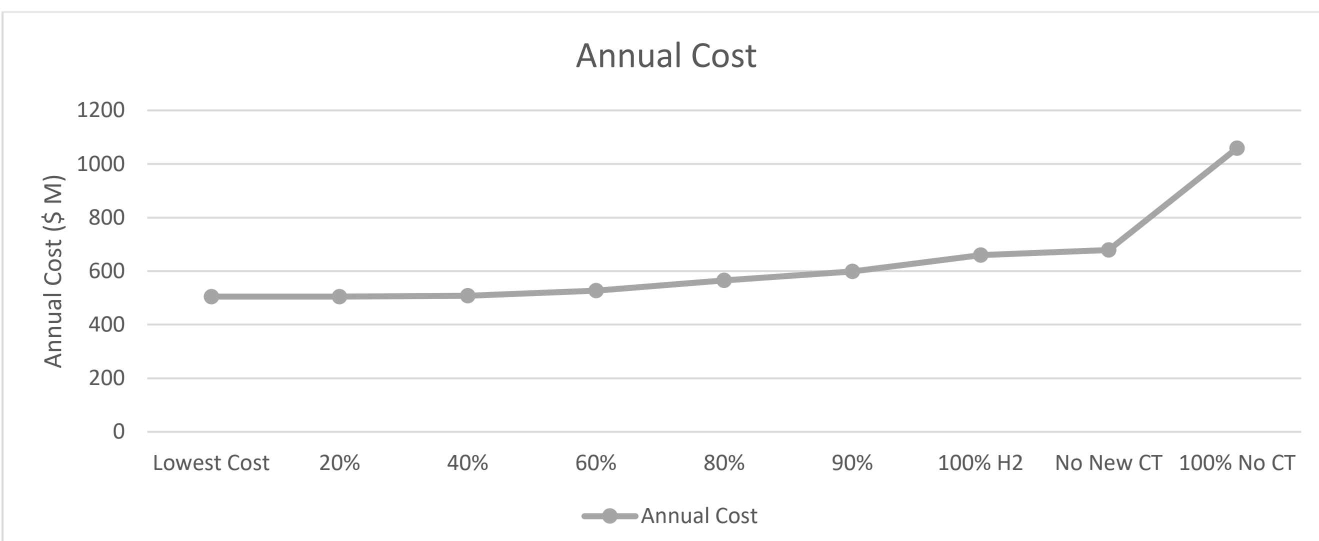
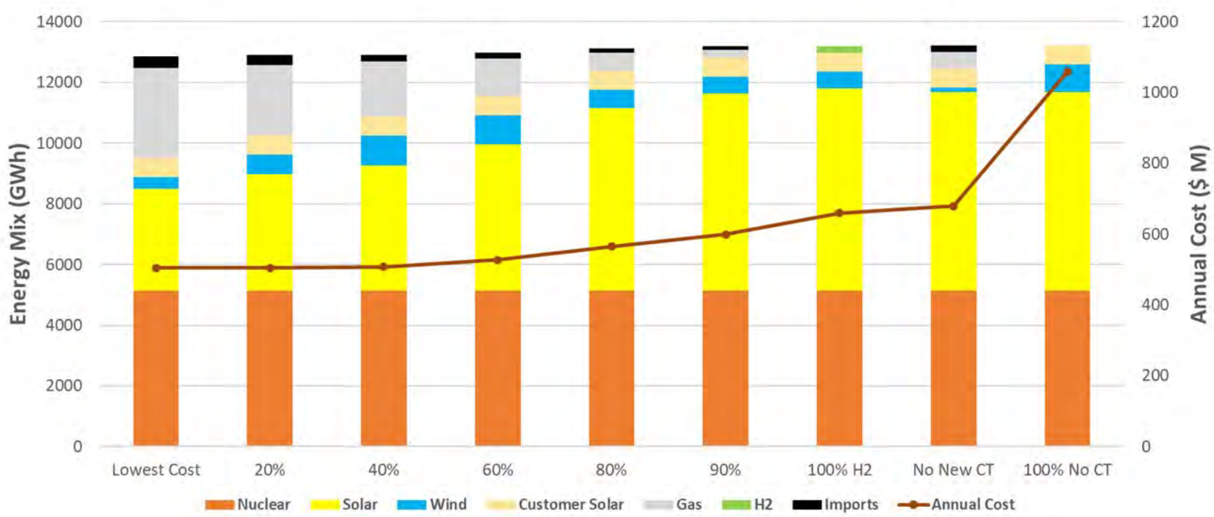


Figure 21b. Annual Cost for Decarbonization Scenarios for 2040



A positive finding is that the continued projected cost declines for renewable and storage costs results in continued increased renewable integration. The lowest cost portfolio selected sufficient renewable energy resources to comply with both New Mexico and Texas renewable requirements in an aggregate on a total system basis. Additionally, as depicted in the Figure 22 below, an 80 percent carbon free scenario is attainable with marginal cost impact to customers. The 80 percent carbon free scenario results in approximately 45 percent renewables for the total system (the presentation of New Mexico REA compliant scenarios is addressed in the following section of the IRP report).

Figure 22. Energy Mix of Carbon Scenarios with Cost Impact for 2040



RESOLVE MODELING –IRP ANALYSIS

Key Assumptions:

- **Retirement Analysis**

Pursuant to the Stipulation Agreement, EPE analyzed any retirements planned within the first five years of the Planning Horizon. This analysis applies to Rio Grande Unit 7 and Newman Units 1-4 for this IRP. To best facilitate this evaluation, EPE hired the services of Burns and McDonnell to assess the conditions of the units and estimate of investment and operating costs to ensure safe and reliable energy for the following extensions. The retirement options were considered in the base case RESOLVE model where the unit extensions were introduced as options competing against the IRP resource options as part of the Base Case. The respective capital and projected O&M expenditures were utilized for each option. Retirement extensions of 5 years were selected by the model for Newman

Unit 1, Newman Unit 3 and Newman Unit 4 based on current cost projections. The retirement extensions will be re-evaluated as part of any future Requests for Proposals ("RFP") evaluation.

- **Newman 6**

  The full Newman 6 capacity is included at full nameplate for any system resource portfolio analysis. However, Newman 6 is not allocated to New Mexico in any jurisdictional analysis.

- **PV 3**

  The full EPE owned PV3 capacity is included at full nameplate for any system resource portfolio analysis. However, PV3 is not allocated to New Mexico in any jurisdictional analysis.

Least Cost System-Wide Portfolio Analysis

EPE initiated the jurisdictional analysis for New Mexico RPS compliance by first establishing the Least Cost System-Wide Portfolio. The Least Cost System-Wide Portfolio capacity additions by year are depicted in Figure 23 below. The portfolio includes selection of retirement extensions for Newman 1, Newman 3 and Newman 4. Additional sensitivities for retirement analysis will be performed plus review of permitting and reliability considerations. Retirement of units are denoted below the x-axis line.

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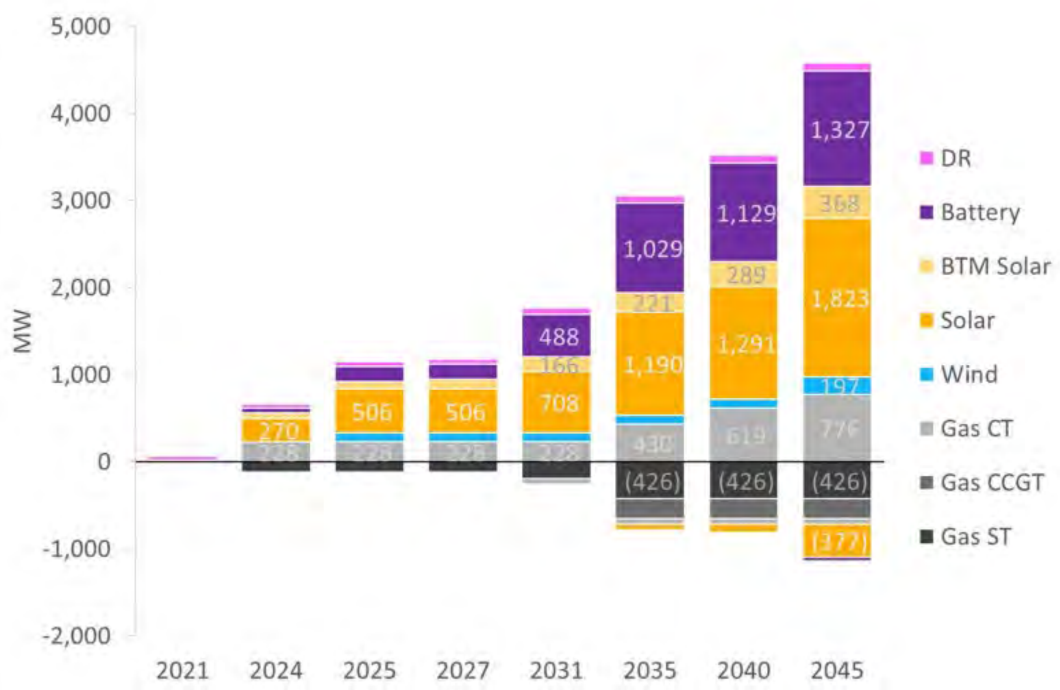
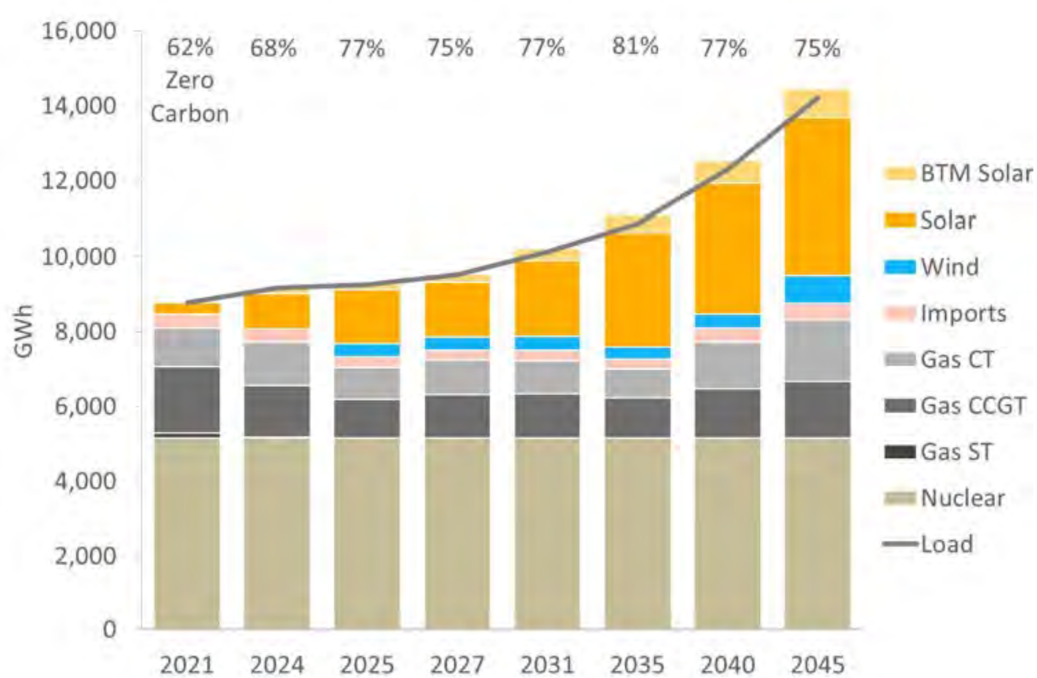
Figure 23. Least Cost System-Wide Portfolio by Year



The resulting resource energy mix of the Least Cost System-Wide portfolio are shown in Figure 24 below.

Figure 24. Least Cost System-Wide Portfolio by year Energy Mix



Jurisdictional Analysis

Because the initial model runs were performed on a total system basis, it was next necessary to assess RPS impacts on a jurisdictional basis. EPE opted to evaluate the jurisdictional impacts by utilizing the Least Cost System-Wide Portfolio as the starting point. The jurisdictional analysis evaluated three different approaches to meeting New Mexico REA requirements, which resulted in three New Mexico specific resource portfolios. The three jurisdictional scenarios are summarized in Table 18 below.

Table 18. New Resource Jurisdictional Allocation Options

	Least Cost ("LC")	**Least Cost + REA Resources** ("LC+REA")	**Separate System Planning** ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

1. **Option-1.** Least Cost Option - System Portfolio Allocated Proportionally (~80/20) and REC Transfer.

   Under this option, all new resources are allocated on a jurisdictional basis, inclusive of gas, and renewable energy. Once allocated, New Mexico's RPS is met through renewable energy delivered to EPE's system from: (1) renewable energy and RECs assigned to EPE's New Mexico jurisdiction; (2) existing dedicated New Mexico RPS resources and associated RECs; and (3) additional RECs without the associated renewable energy assigned to EPE's New Mexico jurisdiction. This option assumes the transfer of stand-alone RECs from EPE's Texas jurisdiction to EPE's New Mexico jurisdiction, an allocation of new gas capacity to New Mexico, which could be converted to run on a higher share of hydrogen fuel in the future, and no allocation of PVGS Unit 3 to New Mexico.

2. **Option 2.** Least Cost Plus REA Resources - System Portfolio Allocated Proportionally plus New Mexico Dedicated Resources.

   Under this option, all new resources are allocated on a jurisdictional basis, except for new gas which is 100 percent allocated to Texas. Additionally, to meet New Mexico's RPS and capacity requirements, New Mexico dedicated renewable and capacity resources were selected to meet New Mexico's jurisdictional requirements. Importantly, this scenario allows capacity pooling and dispatch benefits for system dispatch optimization. Under this scenario, REA compliance is assessed based on annual retails sales, allowing system gas resources when required to supply New Mexico energy needs This scenario is most comparable with past practice except for the exclusion of new gas resources.

3. **Option 3.** Separate Systems for New Mexico and Texas.

   This approach is based on a separate New Mexico portfolio and a separate Texas portfolio. This scenario segregates EPE's system planning and identifies a New Mexico REA compliant portfolio with no allocations of new resources. Additionally, this approach assumes no capacity pooling between New Mexico and Texas, nor does it include joint system dispatch optimization. It also assesses New Mexico REA compliance on an hourly, as opposed to annual, basis. Therefore, there is no leveraging of cross-jurisdictional resources and as such the cost is higher for New Mexico because additional renewables and battery storage must be added to ensure hourly balancing and resource adequacy for New Mexico. This scenario was run both with and without the assumed use of hydrogen combustion generation. As indicated below, the scenario without hydrogen fuel options results in a higher cost. EPE's preliminary grid reliability study has only assessed the impacts of an 80 percent carbon free scenario through 2040, and exclusive reliance on inverter-based technologies has not yet been determined viable under a 100 percent carbon free scenario. This may be addressed in the future through continued technology advancements for both inverter-based resources and grid devices.

The resulting capacity and resource mix for each of the scenarios including New Mexico jurisdictional basis is shown in Figure 25a-25b.

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Figure 25a. Total System & New Mexico Allocation Comparison of Capacity for 2040

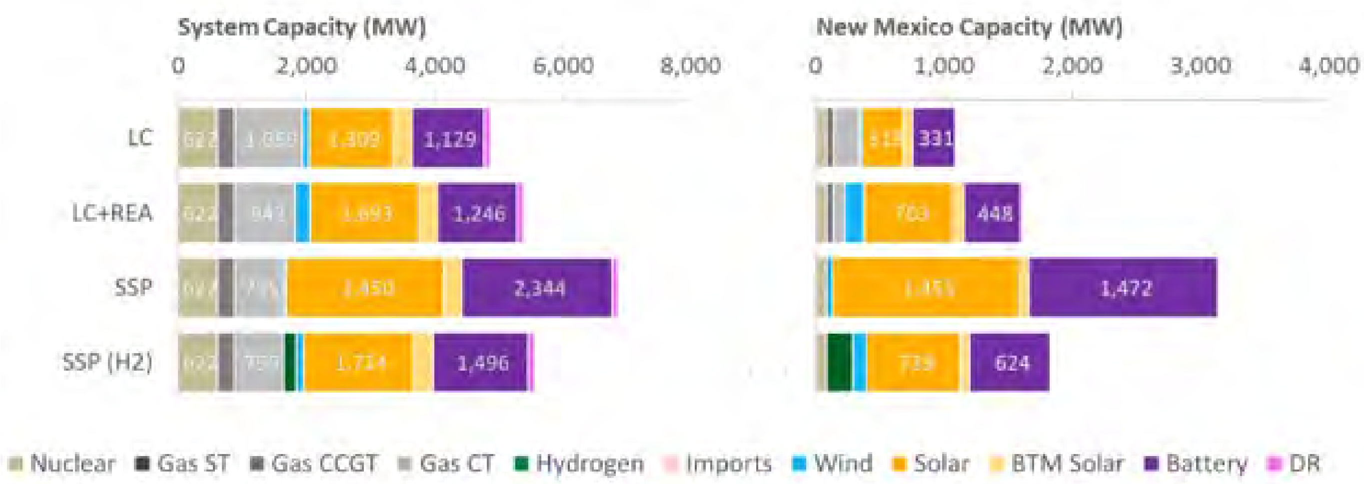
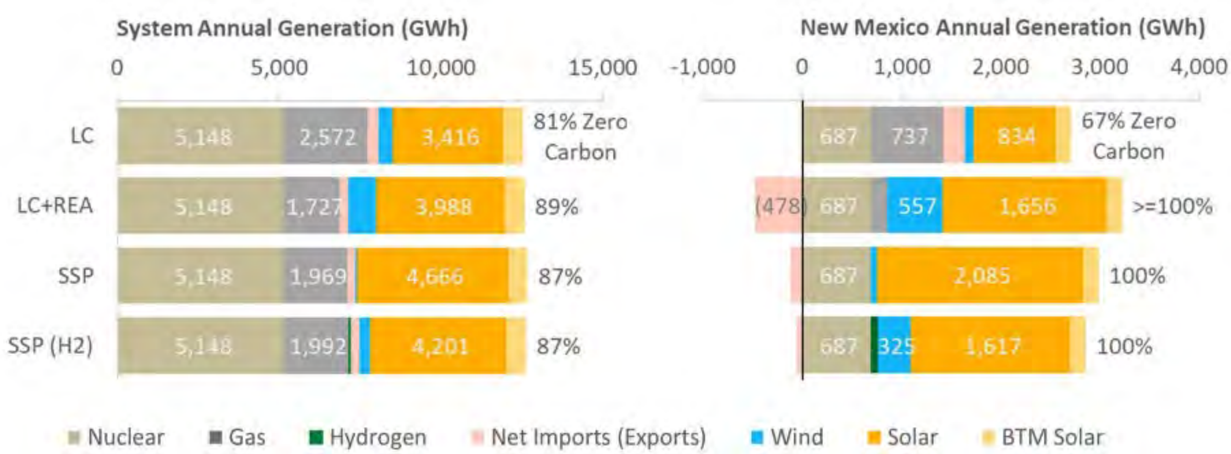
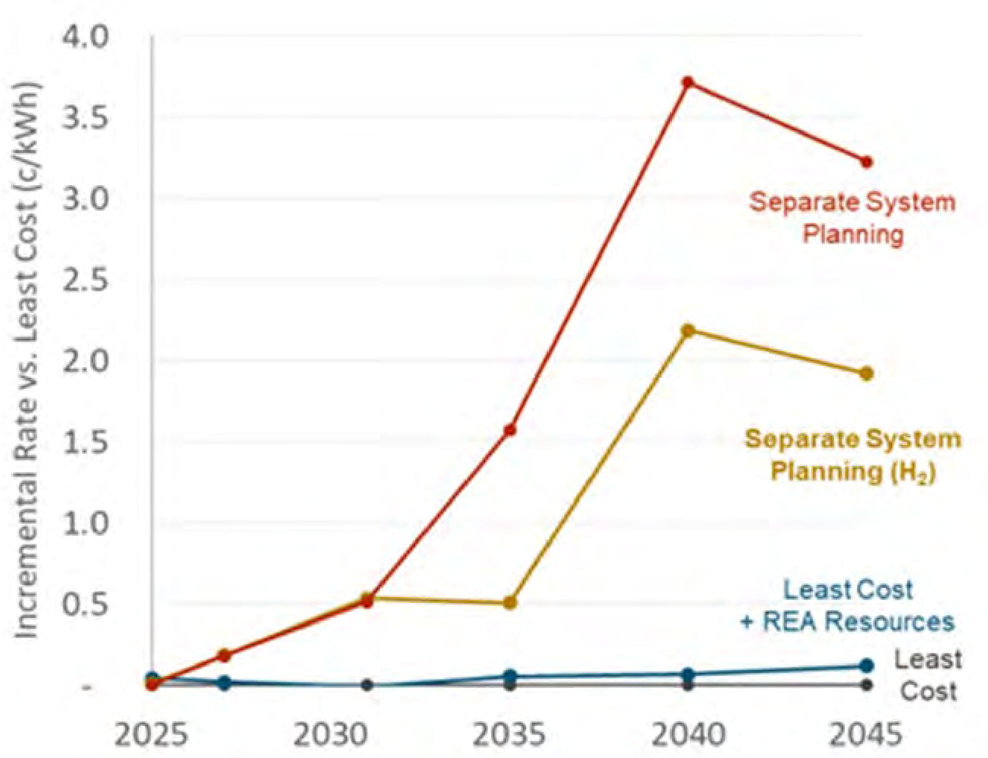


Figure 25b. Total System & New Mexico Allocation Comparison of Energy for 2040



The cost differential between the various jurisdictional approaches may be more easily compared over the planning horizon in Figure 26.

Figure 26. Cost Differential Between Jurisdictional Options



Option 1 presents challenges due to the required transfer of stand-alone RECs between EPE's jurisdictions and the requirement for new gas plant additions. Due to these challenges, EPE presents Options 2 and 3 as the most cost-effective resource options. Both address EPE's multi-jurisdictional planning requirements including the New Mexico RPS requirements and the Texas lowest cost portfolio requirements.

Option 2 assumes that system resources will be proportionally allocated to each jurisdiction. The cost benefits apparent in this scenario, as compare to the Separate System Planning scenario, result from capacity pooling and load diversity during optimal dispatch of both Texas and New Mexico resources while adhering to New Mexico REA requirements. It is important to note that this scenario still requires each jurisdiction, New Mexico and Texas, to acquire sufficient capacity to meet their respective demand and reliability needs. However, it also allows for total system dispatch to optimize both jurisdictional resources to the benefit for both states. As discussed above, this scenario assumes the ability to at times utilize system gas resources to serve New Mexico customers in the event of renewable or carbon free resource energy output unavailability.

Option 3 assumes separate resource planning to address jurisdictional planning requirements. This scenario provides New Mexico the most resource planning autonomy to meet New Mexico's renewable and clean energy standards. Option 3 costs more, however, because the cost benefits associated with capacity pooling and load diversity during optimal dispatch of system-wide resources would not be realized. In short, this approach best addresses the divergence between resource selection standards in Texas and New Mexico but comes at a greater cost to New Mexico.

<u>The Least Cost System-Wide Portfolio Serves as the Base Case for Sensitivities</u>

The Base Case Portfolio was developed utilizing the planned retirements as defined in Table 7. The Base Case utilized the most likely expected values for inputs and provides the most cost-effective portfolio. All other inputs utilized are as described in the preceding sections. The resulting portfolio is as follows:

<u>Mitigating Ratepayer Risk</u>

Risk mitigation for resource selection is achieved in several ways. First, EPE incorporates risk variables for reliability, operational considerations, fuel supply and price volatility and anticipated environmental regulation in its analysis of competing resource options. EPE also analyzes sensitivities in resource selection for variations in forecasted load over time. Finally, because ultimate resource additions can take a considerable amount of time, ratepayer risk mitigation is achieved by constantly updating underlying assumptions as to capacity needs and timing of resource additions.

A. Considerations – Reliability

The most cost-effective portfolio takes into consideration cost, reliability, safety, environmental, and operating characteristics. It reliably introduces a significant amount of solar renewable energy while addressing the intermittency characteristics of solar. Additionally, it selects solar coupled with battery storage which again allows the addition of solar while providing firm output characteristics during peak hours with the battery storage.

Throughout the 2021 IRP, EPE accounted for transmission and reserve margin constraints to capture these parameters while considering total electric system reliability. Each resource analyzed as a portfolio option on a cost-effective basis must also demonstrate its ability to sustain and complement overall system reliability. EPE considered its geographical location and its transmission import limits when developing its optimal portfolio. The resulting portfolio ensures an adequate reserve margin to meet a 2 in 10-year LOLE through 2029 and then shifts to a 1 in 10-year LOLE from 2030 forward.

The recommended portfolio will have sufficient system resources and New Mexico dedicated resources to comply with the current REA requirements. The IRP accounts for these REA requirements by including EPE's existing RPS resource in EPE's L&R and by modeling them as existing resources. The Commission most recently approved EPE's RPS resources in Case No. 18-00109-UT. As part of the IRP evaluation, like EE resource options being modeled above and beyond the EUEA requirements, renewable resources were considered and included in the model, above and beyond the REA requirements.

As stated above, energy efficiency and load management programs were taken into consideration during the IRP, both as a forecasted reduction in load and as a resource option. DR programs and EE are shown in the L&R in Section 4.0. EE resources were considered above the EUEA requirements.

EPE's current generating portfolio provides for minimal exposure to the EPA's guidelines to reduce carbon dioxide emissions. Moving forward, the Plan illustrates that EPE will continue to improve environmental stewardship due to the increased percentage of renewable resources in EPE's optimal portfolio. The inclusion of renewable resources above regulatory requirements demonstrates EPE's efforts to limit its carbon footprint.

Given the increased amount of renewable resources and the introduction of battery storage, the most cost-effective portfolio has a greater diversity of resources.

B. Alternative Portfolios (sensitivities, carbon tax)

Sensitivity Analysis

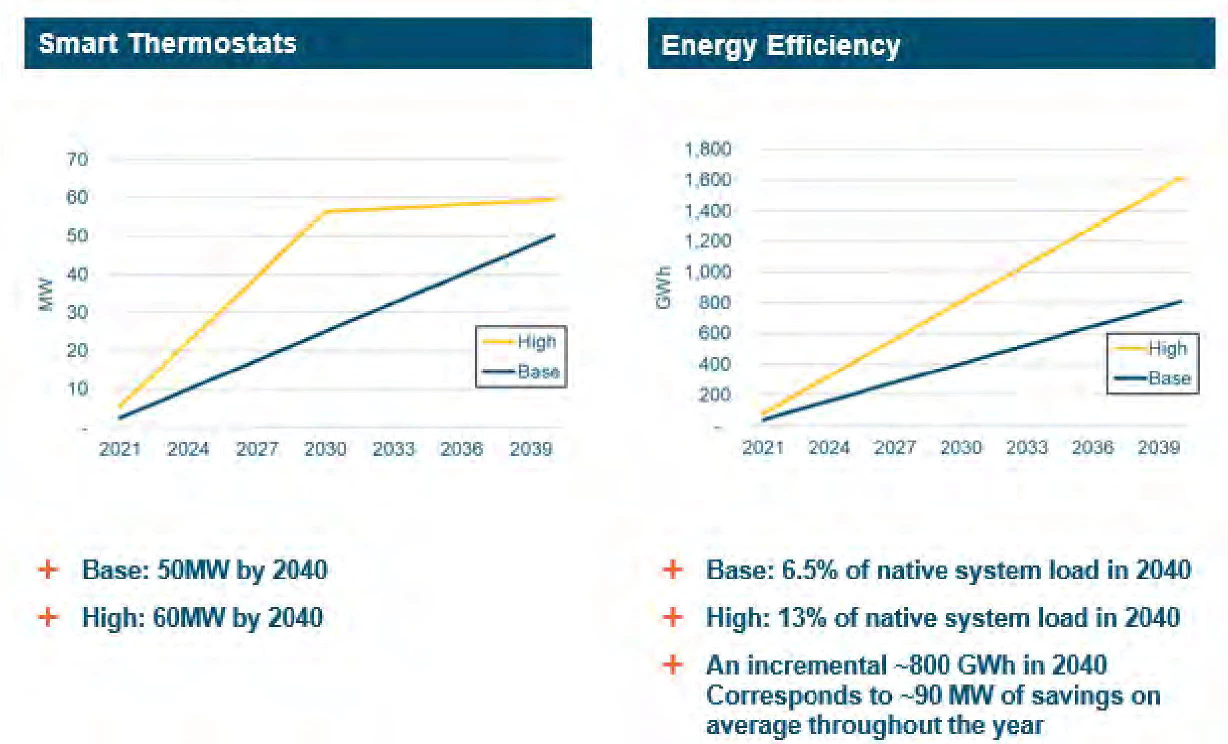
EPE analyzed various sensitivities to capture the cost differences and changes to the resource expansion plan. The sensitivities included variations to projected load, forecasted natural gas prices, and carbon tax costs at different price thresholds. Following is a description of the high demand side management sensitivity. Results of all sensitivities conducted for this IRP may be found in Section 7 of E3's report provided as Attachment D-4.

High Demand Side Management Sensitivity Analysis

EPE opted to run a high Demand Side Management (DSM) sensitivity to assess portfolio impacts to the Least Cost System-Wide scenario. This approach was selected because EPE's current customer load characteristics do not provide a significant amount of load management options outside of thermostat control DSM options for refrigerated air systems. For example, only 8 percent of customers have pools and only 15 percent of customers have electric water heaters. This does not offer much in the form of substantive DSM options. However, EPE understands that this will change as greater electrification of load takes place. Therefore, EPE modeled a high DSM sensitivity case based on a high DSM and Energy

Efficiency adoption. It is noted, that in addition to the thermostat program expansion, EPE also assumed managed electric vehicle charging in the future which is also a form of DSM. Figure 27 describes the high DSM/EE scenario.

Figure 27. High DSM/EE Sensitivity Scenarios



Figures 28a-28b show the resulting portfolio impact denoted as a change in cumulative capacity addition reduction and change in annual generation by resource type and year vs. the reference case.

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Figure 28a. High DSM/EE Resulting Change in Cumulative Capacity vs. Ref Case

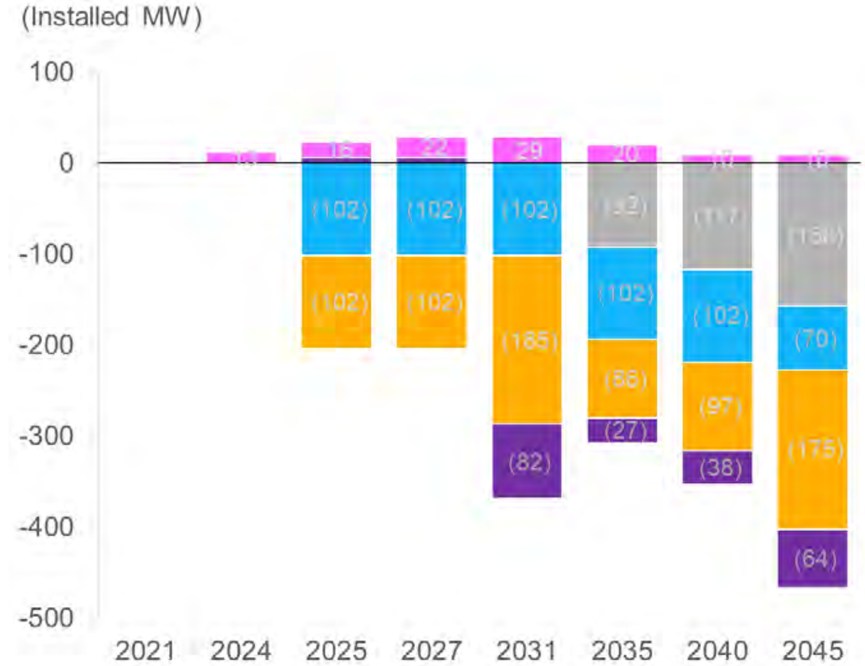
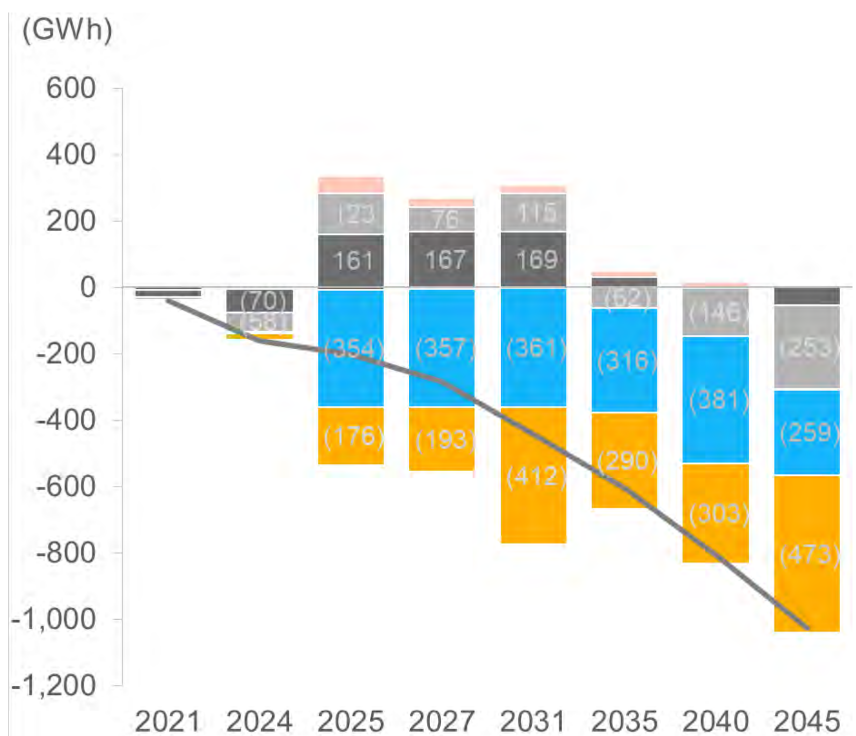


Figure 28b. High DSM/EE Resulting Change in Annual Generation vs. Ref Case



C. Recommended Portfolio

EPE presents as its recommended resource portfolio, the Least Cost-plus REA option, ("Option 2"). The resulting incremental resource additions for Option 2, for Total System, are shown in Table 19a. Similarly, the resulting incremental resource additions for Option 2, for New Mexico, are shown in Table 19b.

Table 19a. Option 2 Incremental Resource Additions for Total System, (MW)

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*126*	*1*	*283*	*607*	*179*	*487*
Gas New	-	-	-	*141*	*134*	*108*
Gas 5-yr Extension	*74*	*313*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	*159*	-	*251*	*689*	*306*	*624*
Wind	*203*	-	-	-	*28*	*69*

Table 19b. Option 2 Incremental Resources Additions for New Mexico, (MW)

Resource Category	2025	2027	2031	2035	2040	2045
Battery	*94*	*1*	*50*	*192*	*101*	*352*
Gas_CT	-	-	-	-	-	-
Gas 5-Yr Extension	*15*	*63*	-	-	-	-
Geothermal	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-
Solar	-	-	*59*	*303*	*225*	*199*
Wind	*122*	-	-	-	*28*	-

The actual resource additions will be determined via future RFP solicitations and dependent on actual proposals and pricing. EPE will pursue this portfolio by separate jurisdictional RFP specific to New Mexico and Texas. This will allow EPE to pursue respective jurisdictional specific RPS requirements to meet demand. The separate RFP solicitations and resulting regulatory approval filings will also provide New Mexico with the autonomy it has demonstrated interest in. While the resources will be pursued via separate RFPs, the total system resource portfolio's capacity will be pooled and optimally dispatched at a system wide level to offer the cost benefits shown by the Least Cost plus REA analysis. As stated above, the retirement extensions of the existing units will be re-evaluated as part of future RFP resource selection.

Under this IRP, REA compliance will be measured annually to ensure New Mexico assigned renewable resources and carbon free resources meet or exceed the New Mexico RPS. Including the 100 percent carbon free requirement. For example, there may be hours of the year that gas generation may serve New Mexico load; however, the total New Mexico assigned carbon free resources' output will equal or exceed the total annual New Mexico retail sales to ensure compliance with the 100 percent carbon free requirement.

LOADS AND RESOURCES

The final EPE System and New Mexico L&R are presented in Figure 5a-5b and 6a-6b for the respective L&R tables. Given that the RESOLVE analysis looks at five discrete build years, the L&R distributes some of the resource additions to address preceding years due to retirements and associated deficiencies.

D. 2021 IRP Four-Year Action Plan

EPE's four-year action plan includes the following steps:

- EPE will continue moving forward with the selected resources previously approved by the Commission in Case Nos. 19-00099-UT and 19-00348-UT (Hecate I and II and Buena Vista I and II). These resources have an anticipated Commercial Operation Date ("COD") of 2022.
- EPE will complete the regulatory approval process for EPE's 2021 Annual Renewable Energy Plan filed May 5, 2021, and file subsequent annual reports and plans in 2022, 2023, 2024, and 2025 pursuant to 17.9.572 NMAC and the New Mexico REA.
- EPE will complete the regulatory approval process for the 2022-2024 Energy Efficiency and Load Management Plan filed July 16, 2021 and will file a subsequent 3-year plan pursuant to 17.7.2 NMAC and the EUEA.
- EPE will issue a New Mexico RFP in 2021 to address current capacity needs and RPS resource needs to meet the REA 2025 target of 40 percent.
- EPE will complete a Demand Side Management potential study.
- EPE will continue to consider voluntary customer programs for renewable energy.
- EPE will file for abandonment of units that are past their useful lives.

X. DESCRIPTION OF PUBLIC PROCESS

A. Overview of the Public Process

The purpose of the Public Process is for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP (17.7.3.9.H NMAC).

Curtis Hutcheson, Manager-Regulatory Case Management, chaired the public participation process. Mr. Hutcheson scheduled the original public meetings and then coordinated the development of the final meeting schedule and meeting agendas with input from the public participants. The public participants were encouraged to place items on the agenda for discussion at the public meetings. The result was three additional meetings. Due to the pandemic, the public meetings were all held online, using WebEx and Zoom platforms. EPE continues to use the NMIRP@epelectric.com email, consisting of EPE employees directly related to the IRP process, to provide the public participants with updates on available presentation materials and future meetings. Public participants also communicated with EPE through this email address to ask questions and to place items on the agenda of the public participation meetings. Multiple EPE employees received the emails to ensure the messages were received.

EPE encouraged public involvement in its Public Process and hosted a total of nine public advisory meetings over the course of approximately 12 months. During the public meetings, EPE presented information and material on its Planning Process by Company subject matter experts and EPE also received feedback from the Participants. EPE structured the Public Process to be inclusive and interactive. The online meetings were set up so that the Participants could view presentation materials taking place during each meeting and hear audio. The remote Participants were able to submit questions through the Q&A or chat conversation panels.

EPE recorded some meetings, upon request, and posted these on EPE's IRP website.

Additional discussion and feedback also took place outside of scheduled meetings. The Participants submitted questions, requests, articles, and essays for consideration by EPE and other members of the public. EPE responded to all written requests for information in writing as described in the Stipulation Agreement.

By attending any public meeting, the Participants were automatically enrolled in EPE's attendance invitation list, where they were notified of upcoming meeting information, new website material, written questions and responses, and other IRP updates. Another available resource for the Participants was EPE's IRP website which includes helpful information and resources, such as IRP presentation material, written questions and responses, meeting schedule information, remote participation information, past IRP information, and rules and statutes information.

The sections below will describe the Public Process in more detail.

B. Notice and Public Outreach

EPE initiated the Public Process by publishing notice in the Las Cruces Sun-News, a newspaper of general circulation in every New Mexico County in which EPE serves, 30 days prior to the first scheduled meeting, which was July 10, 2020. EPE also included notice of the Participants meetings in New Mexico customer bill inserts. Additionally, EPE provided notice 30 days prior to the first scheduled meeting to the Commission, intervenors in its most recent general rate case, intervenors in its most recent renewable energy procurement case at the time, and intervenors in its most recent Energy Efficiency/Load Management Plan case. The notice and certificates of service were filed with the Commission's Records Bureau.

1. Copy of Published Public Notice

A copy of the published Public Notice, which was also used for bill inserts, publication in the Las Cruces Sun News, and email notifications, 30 days prior to the first scheduled meeting, is attached as Attachment E-1. The attachment also contains the Proof of Publication, Affidavit of notification to customers, and Certificate of Service filed with the Commission on May 13, 2021. The notice was served to intervenors in its most recent general rate case, and participants in EPE’s most recent renewable energy, energy efficiency and load management, and IRP proceedings. The notice contained a brief description of the IRP process, time, date, and location of the first meeting, a statement that interested individuals should notify the utility of their interest in participating in the process, and utility contact information.

C. Attendance

An average of 48 people attended EPE's public advisory meetings remotely as attendees over the course of the approximately 12-month Public Process. There was an average of 10 panelists during each meeting.

Public participation consisted of continuous attendance from the participants who were very active in the Q&A and chat panels and were engaged throughout the entire Public Process. There were also representatives from certain groups and companies, such as Coalition for

Clean Affordable Energy, Western Resource Advocates, Solar Smart Living, Cypress Creek Renewables, City of Las Cruces, and others. NMPRC Staff was represented at each meeting.

Participants demonstrated interest and a disparate level of understanding of the Planning Process, and an appreciation, to some degree, of the complexity involved.

D. Meeting Schedule and Format

EPE's original public advisory meeting schedule included six meetings; but, with the addition of three meetings requested by public participants, the final schedule consisted of nine meetings. EPE modified its initial meeting schedule to accommodate several requests of the Participants. For example, EPE scheduled extra meetings to address topics to be covered in more detail as requested by the Participants. Attachment E-2 shows the original and final public advisory group meeting schedule.

Meetings were typically held on Friday's at 2 pm, for the duration of 2.5 hours. In EPE's experience, meetings held outside of normal business hours did not increase public participation. All meetings were held online.

The schedule was structured to cover the required data as quickly and fully as possible to allow more time for development of the cost-effective portfolio. EPE has learned from past IRPs that Participants tend to be more focused on this portion of the IRP public process.

The structure of the meetings was presentation oriented. Typically, presentations were completed before answering questions submitted through the Q&A and chat panels, unless directly related to terms used in the presentation for clarification. Additionally, at the end of each meeting, submitted questions were answered as time permitted.

EPE presented topics required in the Rule for the Public Process, as well as more detailed information on those topics to better inform the Participants on the issues addressed in the IRP. These detailed topics were covered at the beginning of the Public Process so that more time could be dedicated to the development of the most cost-effective portfolio and review of the IRP report.

In response to public feedback, and to provide more information and explanation of the modeling process to the participants, EPE added three additional meetings to address specific topics; first on November 9, 2020, second on February 5, 2021, and the third on March 19, 2021.

During the November 9, 2020, meeting, the Public Participants provided a slide presentation, then there was a discussion by EPE regarding EPE's expectations as to its generation portfolio and power procurement in 2040 and 2045, consistent with REA requirements regarding renewable and non-carbon sources, EPE's expectations regarding "must-run" resources in a non-carbon world and implications for renewable resources, including the use of curtailments, EPE's expectations regarding the level of reliability appropriate for the system today and in 2040, and how EPE expects to analyze the provision and cost of defined levels of reliability, discussion by EPE of native load and system requirements in 2020, including how EPE met peak demand during the summer peak period, discussion of future meeting agendas, and additional scheduled meetings.

During the February 5, 2021, meeting, EPE presented the modeling update in a joint presentation with E3 and discussed dates of future meetings.

During the March 19, 2021, meeting, EPE presented an IRP modeling status summary, New Mexico Renewable Energy Act requirements, transmission for new resources discussion, an assumptions update, model updates and results, and next steps.

The last three meetings were on June 1, July 1, and September 2, 2021. For the June 1 meeting, EPE presented the load forecast and the preliminary modeling results. EPE emailed the draft IRP report to the participants on June 15, 2021 so they could review before the July 1 meeting. On July 1, EPE presented the jurisdictional analysis and received comments on the draft IRP report. On August 15, 2021, EPE emailed the final draft of the IRP report. Finally, at the September 2, 2021 meeting, EPE received feedback from the participants on the final report.

E. Public Input

EPE structured the Public Process to solicit, receive, and consider public comment regarding the development of its IRP in several ways. EPE encouraged Participants to:

- participate in the online public advisory meetings and give their input during the meetings,
- submit written requests for information through the Q&A and chat panels during the meetings,
- send EPE their written input or requests by email, during or after scheduled meeting,

EPE received and considered all views and opinions expressed during the Public Process.

F. Conclusion of Public Advisory Process

Due to the pandemic and New Mexico Governor Gresham's Executive Orders, EPE made a significant effort to provide the public as much access as possible to make it a more inclusive and interactive process. By providing the Participants with additional features such as increasing the number of meetings and public discussion time, and including a written request and response option, EPE made the public process as accessible and as effective as possible under the circumstances.

XI. CONCLUSION

The identified resource additions result in the optimal cost-effective resource portfolio and were identified through a robust and comprehensive Planning Process. The resulting resource portfolio additions include a mix of solar, battery storage, and conventional gas generation. The battery storage and conventional gas generation resources compliment the solar resources, which are intermittent in nature. It is noted that the actual resource additions in the future will be determined by results of competitive requests for proposals and may differ based on future changes to forecasted loads, economic conditions, technological advances, specific generation resource proposals, and environmental and regulatory standards.

Appendix A Resource Assumptions

Table 1. Resource Lifetime (years)

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

Table 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)	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)	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 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**

Table 4. Real Levelized Cost ($/kW-yr) (2021 $)[1]

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[2]	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

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[1] The levelized cost includes interconnection costs.

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

Table 5. Capacity Factor (%)

Resource	Capacity Factor
Solar[3]	32%
BTM Solar	24%
Wind (Artesia)	44%
Wind (ABQ)	50%
Wind (Lordsburg)	37%
Geothermal	80%

Table 6. Real Levelized Cost of Energy ($/MWh) (2021 $)[4]

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 7. Thermal Resource Characteristics

Resource	Heat Rate (MMBtu/MWh)	Variable O&M (2021$/MWh)
Gas Peaker	10.1	$1
Biomass	13.5	$5
Nuclear (SMR)	10.0	$2

[3] The capacity factor for solar PV differs slightly by location. This value is used for illustrative purposes for calculating the levelized cost of energy.
[4] 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. 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 9. Hydrogen Retrofit Cost ($/kW-yr) (2021 $)

Resource	Additional Cost
Gas Plants[5]	$12

[5] This is the assumed cost of converting a natural gas-fired plant to burn hydrogen fuel.

Appendix B Resource Assumptions

Resource Input	Source of Data
Resource Potential • Technical potential (MW)	*Given the abundance of solar and wind resources relative to the size of EPE's system, no limits are applied for renewables*
Technology Cost • Capital cost ($/kW) • Fixed O&M ($/kW-yr) • Interconnection cost ($/kW)	**NREL Annual Technology Baseline (ATB) for Renewables/Thermal** *Supplemented with regional cost adjustments and interconnection costs from NREL ReEDS datasets* **Lazard Levelized Cost of Storage 6.0 / NREL ATB for Batteries** *Lazard's LCOS 6.0 costs are used for batteries in the near term and the long-term cost decline trajectory from the NREL ATB is applied*
Financing • Project capital structure • Tax credits	**E3 Pro Forma Financial Model** *Calculates price for a long-term cost-based power purchase agreement between a third-party developer and a credit-worthy utility*
Transmission • Existing headroom • Cost to expand transmission	**El Paso Electric System Planning team** *Provided a simplified representation of the transmission system for purposes of determining headroom on the transmission system and the cost of expansion*

Attachment A-1: Acronyms

ACE	-	Affordable Clean Energy
A/C	-	Air/Conditioning
ADSTF	-	Anchor Data Set Task Force
AMI	-	Advanced Metering Initiative
AMS	-	Automated Metering System
APS	-	Arizona Public Service Company
ATC	-	Available Transfer Capacity
BA	-	Balancing Area
BPSPRTF	-	BPS Planning Task Force
BTM	-	Behind the Meter
Btu	-	British thermal unit
CAA	-	Clean Air Act
CAGR	-	Compound Annual Growth Rates
CAISO	-	California Independent System Operator
CC	-	Combined Cycle
CCGT		Combined Cycle Gas Turbine
CCN	-	Certificate of Convenience and Necessity
CDD	-	Cooling Degree Days
CO2	-	Carbon Dioxide
CPP	-	Clean Power Plan
CPP	-	Critical Peak Pricing
CT	-	Combustion Turbine
cts		Cents
CWIP	-	Construction Work in Progress
DG	-	Distributed Generation
DR	-	Demand Response
DRPP	-	Demand Response Pilot Program
DS	-	Data Subcommittee
DSM	-	Demand Side Management
E3	-	Energy+Envronmental Economics
EE	-	Energy Efficiency
EHV	-	Extra High Voltage
EIM	-	Energy Imbalance Market
ELCC	-	Effective Load Carrying Capability
EPA	-	Environmental Protection Agency
EPE	-	El Paso Electric
ERCOT	-	Electric Reliability Council of Texas
EUEA	-	Efficient Use of Energy Act
EUL	-	Average Estimated Useful Life
EV	-	Electric Vehicle
FCPP	-	Four Corners Power Plant
FERC	-	Federal Energy Regulatory Commission
FPPCAC	-	Fuel and Purchased Power Cost Adjustment Clause
GE	-	General Electric
GHG	-	Greenhouse Gas
GWh		Giga Watt hours (1000 MWh)
H2	-	Hydrogen
HFAB	-	Holloman Air Force Base
HDD	-	Heating Degree Days
HV	-	High Voltage
HVAC	-	Heating, Ventilation, and Air Conditioning
HVDC	-	High Voltage Direct Current
IBR	-	Inverter Based Resource
ICAP	-	Installed Capacity
IOU	-	Investor Owned Utility
IRP	-	Integrated Resource Plan
ITC	-	Investment Tax Credit
JSIS	-	Joint Synchronized Information Subcommittee
kV	-	kilo Volt
kVA	-	kilo Volt Ampere
kW	-	kilo Watts
kWh	-	kilo Watt hours
L&R	-	Loads and Resources Table
LC	-	Least Cost
LCOE	-	Levelized Cost of Energy
LED	-	Light Emitting Diode
LF	-	Load Factor
LOLE	-	Loss of Load Expectation
LM	-	Load Management
LRTF	-	Loads and Resources Task Force
LTPPA	-	Long-Term Purchased Power Agreement
MMBtu	-	One million British thermal units
MMcf	-	One Million cubic feet (gas)
MPS	-	Montana Power Station
MS	-	Modeling Subcommittee
MVA	-	Mega Volt Amp
MVS	-	Modeling and Validation Subcommittee
MW	-	Mega Watt (1,000 kW)
MWh	-	MegaWatt-hours (1,000 kWh)
NAAQS	-	National Ambient Air Quality Standards
NARUC	-	National Association of Regulatory Utility Commissioners
NERC	-	North American Electric Reliability Council
NMAC	-	New Mexico Administrative Code
NMPRC	-	New Mexico Public Regulation Commission
NMSA	-	New Mexico Statutes Annotated
NOAA	-	National Oceanic and Atmospheric Administration
NOx	-	Nitrogen Oxide
NREL	-	National Renewable Energy Laboratory
O&M	-	Operation and Maintenance Expenses
OASIS	-	Open Access Same Time Information Systems
OATT	-	Open Access Transmission Tariff
PCAP	-	Perfect Capacity
PM	-	Particulate Matter
PNM	-	Public Service Company of New Mexico
PPA	-	Power Purchase Agreement
PRM	-	Planning Reserve Margin
PSLF	-	Positive Sequence Load Flow
PTP	-	Point to Point Transmission Service
PTR	-	Peak Time Rebate
PUCT	-	Public Utility Commission of Texas
PUHCA	-	Public Utility Holding Company Act
PURPA	-	Public Utility Regulatory Policies Act
PV	-	solar photovoltaic
PVNGS	-	Palo Verde Nuclear Generating Station
QF	-	Qualifying Facility
RASS	-	Residential Appliance Saturation Survey
RAC	-	Reliability Assessment Committee
RCT	-	Reasonable Cost Threshold
REA	-	New Mexico Renewable Energy Act
REC	-	Renewable Energy Certificate
Recip	-	Reciprocating Engine
RFP	-	Request For Proposal
RGEC	-	Rio Grande Electric Co Operative
RPS	-	Renewable Portfolio Standard
SCR	-	Short Circuit Ratio
RTO	-	Regional Transmission Organization
SDS	-	Scenario Development Subcommittee
SEC	-	Securities and Exchange Commission
SNMIC	-	Southern New Mexico Import Capability
SNMTS	-	Southern New Mexico Transmission System
SO2	-	Sulfur dioxide
SPP	-	Southwest Power Pool
SRS	-	System Review Subcommittee
SRP	-	Salt River Project
STATCOM	-	Static Compensator
SSP	-	Separate System Planning
SVC	-	Static VAR Compensator
StS	-	Studies Subcommittee
SWAT	-	Southwest Area Transmission
TOD	-	Time-of-Day
TEP	-	Tucson Electric Power Company
TOU	-	Time-of-Use
TTC	-	Total Transfer Capability
UPC	-	use per customer
UVLS		Under Voltage Load Shed
VAR	-	volt-ampere reactive
VOC	-	Volatile Organic Compounds
WECC	-	Western Electricity Coordinating Council
WSCC	-	Western Systems Coordinating Council
WSPP	-	Western Systems Power Pool

Attachment B-1: 2021 Forecast

APPENDIX A
EL PASO ELECTRIC COMPANY
2021-2030 DEMAND AND ENERGY FORECAST

Summary

ENERGY (GWH)	2020 (1)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-YR (7) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		9,127	9,337	9,496	9,640	9,789	9,954	10,134	10,317	10,510	10,712	
Expected:	8,674	8,848	9,057	9,210	9,348	9,489	9,645	9,816	9,989	10,171	10,361	**1.8**
Lower Bound		8,568	8,776	8,925	9,055	9,188	9,336	9,498	9,661	9,831	10,009	
Less: DG (3)		37	73	104	134	164	194	224	254	283	312	
Less: EE (4)		40	81	121	161	202	242	282	323	363	403	
Plus: EV (5)		1	2	4	6	8	12	16	22	30	40	
Native System Energy												
Upper Bound		9,051	9,183	9,268	9,338	9,413	9,504	9,611	9,722	9,846	9,980	
Expected:	**8,674**	**8,772**	**8,905**	**8,989**	**9,058**	**9,131**	**9,221**	**9,325**	**9,435**	**9,555**	**9,685**	**1.1**
Lower Bound		8,492	8,627	8,710	8,777	8,849	8,937	9,040	9,147	9,264	9,390	
Total System Net Energy (6)												
Upper Bound		9,014	9,145	9,229	9,299	9,372	9,463	9,569	9,681	9,804	9,938	
Expected:	**8,507**	**8,735**	**8,868**	**8,952**	**9,021**	**9,094**	**9,184**	**9,288**	**9,398**	**9,518**	**9,648**	**1.3**
Lower Bound		8,455	8,591	8,675	8,743	8,815	8,904	9,007	9,114	9,231	9,358	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,259	2,313	2,354	2,384	2,426	2,466	2,510	2,547	2,599	2,647	
Expected:	2,173	2,137	2,188	2,225	2,252	2,292	2,330	2,371	2,406	2,457	2,503	**1.4**
Lower Bound		2,016	2,062	2,096	2,120	2,158	2,193	2,232	2,266	2,314	2,358	
Less: DG		9	19	26	34	41	49	56	64	71	79	
Less: EE		8	15	23	31	38	46	54	62	69	77	
Plus: EV		0	1	2	3	4	6	8	11	15	20	
Native System Demand:												
Upper Bound		2,242	2,280	2,305	2,319	2,346	2,371	2,400	2,424	2,463	2,500	
Expected:	**2,173**	**2,121**	**2,155**	**2,177**	**2,190**	**2,216**	**2,240**	**2,269**	**2,292**	**2,331**	**2,367**	**0.9**
Lower Bound		1,999	2,030	2,050	2,061	2,086	2,109	2,137	2,159	2,198	2,234	
Total System Demand												
Upper Bound		2,232	2,269	2,294	2,309	2,336	2,361	2,390	2,413	2,453	2,489	
Expected:	**2,147**	**2,112**	**2,146**	**2,168**	**2,181**	**2,207**	**2,231**	**2,260**	**2,283**	**2,322**	**2,358**	**0.9**
Lower Bound		1,991	2,022	2,042	2,053	2,079	2,102	2,130	2,152	2,191	2,226	
Interruptible Load		56	56	56	56	56	56	56	56	56	56	
Upper Bound		2,176	2,211	2,235	2,248	2,274	2,299	2,327	2,350	2,390	2,426	
Expected:	**2,147**	**2,056**	**2,090**	**2,112**	**2,125**	**2,151**	**2,175**	**2,204**	**2,227**	**2,266**	**2,302**	**0.7**
Lower Bound		1,935	1,968	1,990	2,002	2,028	2,052	2,080	2,103	2,142	2,178	

Footnotes:
(1) 2020 are Actual data, Native System Peak occurred on July 13.
(2) Net For Load is forecasted load before the removal of DG and EE.
(3) Impact from Distributed Generation.
(4) Impact from Energy Efficiency.
(5) Impact from Electric Vehicles.
(6) Total System includes transmission wheeling Losses To Others.
(7) 10-Year Compounded Average Growth Rate.

/s/ James Schichtl
Jim Schichtl
Vice President & Government Affairs

APPENDIX A
EL PASO ELECTRIC COMPANY
2031-2040 DEMAND AND ENERGY FORECAST

Summary

ENERGY (GWH)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	20-YR (1) CAGR
Native System Forecast (NFL)											
Upper Bound	10,915	11,117	11,328	11,548	11,773	12,000	12,232	12,471	12,717	12,979	
Expected:	10,551	10,740	10,937	11,143	11,354	11,566	11,784	12,007	12,238	12,484	1.8
Lower Bound	10,187	10,362	10,547	10,738	10,935	11,133	11,335	11,543	11,758	11,989	
Less: DG	341	371	399	428	457	485	513	541	569	597	
Less: EE	444	484	524	565	605	646	686	726	767	807	
Plus: EE (5)	54	72	95	126	167	221	291	384	507	668	
Native System Energy:											
Upper Bound	10,119	10,262	10,421	10,596	10,786	10,993	11,223	11,482	11,780	12,135	
Expected:	**9,819**	**9,957**	**10,109**	**10,276**	**10,459**	**10,657**	**10,876**	**11,124**	**11,408**	**11,748**	1.5
Lower Bound	9,519	9,651	9,797	9,957	10,132	10,320	10,529	10,765	11,037	11,361	
Total System Net Energy:											
Upper Bound	10,077	10,220	10,379	10,553	10,744	10,951	11,180	11,440	11,738	12,093	
Expected:	**9,782**	**9,920**	**10,072**	**10,239**	**10,422**	**10,619**	**10,839**	**11,087**	**11,371**	**11,711**	1.6
Lower Bound	9,487	9,619	9,765	9,925	10,100	10,288	10,497	10,733	11,005	11,329	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,695	2,736	2,793	2,844	2,897	2,943	3,006	3,062	3,120	3,174	
Expected:	2,549	2,587	2,642	2,692	2,743	2,786	2,846	2,900	2,956	3,007	1.6
Lower Bound	2,402	2,439	2,492	2,539	2,588	2,629	2,687	2,739	2,792	2,841	
Less: DG	86	93	101	108	115	122	129	136	143	150	
Less: EE	85	92	100	108	115	123	131	138	146	154	
Plus: EV	26	35	46	61	81	107	142	187	247	325	
Native System Demand:											
Upper Bound	2,538	2,571	2,623	2,674	2,731	2,788	2,870	2,957	3,060	3,179	
Expected:	**2,404**	**2,436**	**2,488**	**2,538**	**2,593**	**2,648**	**2,728**	**2,813**	**2,913**	**3,028**	1.7
Lower Bound	2,270	2,302	2,352	2,401	2,455	2,509	2,587	2,669	2,766	2,877	
Total System Demand:											
Upper Bound	2,527	2,561	2,613	2,664	2,721	2,778	2,859	2,946	3,050	3,169	
Expected:	**2,395**	**2,427**	**2,479**	**2,529**	**2,584**	**2,639**	**2,719**	**2,804**	**2,904**	**3,019**	1.7
Lower Bound	2,263	2,294	2,345	2,394	2,448	2,501	2,579	2,661	2,758	2,869	
Interruptible Load:	56	56	56	56	56	56	56	56	56	56	
Upper Bound	2,464	2,497	2,549	2,600	2,657	2,714	2,795	2,882	2,986	3,105	
Expected:	**2,339**	**2,371**	**2,423**	**2,473**	**2,528**	**2,583**	**2,663**	**2,748**	**2,848**	**2,963**	1.6
Lower Bound	2,214	2,246	2,297	2,345	2,400	2,453	2,531	2,613	2,710	2,821	

Footnotes:
(1) 20-Year Compounded Average Growth Rate.

Attachment B-2: 2021 Energy Forecast by Jurisdiciton

Native System Energy	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Texas										
Residential	2,692,520	2,748,587	2,801,562	2,843,496	2,889,745	2,944,841	3,012,227	3,084,291	3,159,861	3,244,321
Commercial & Industrial, Small	1,973,888	1,995,427	2,000,737	2,002,237	2,004,005	2,008,668	2,014,241	2,019,958	2,027,824	2,037,463
Commercial & Industrial, Large	972,050	976,384	980,005	982,995	985,436	987,399	988,946	990,130	990,999	991,593
Street Lighting	41,523	42,056	42,506	42,961	43,420	43,880	44,323	44,748	45,182	45,638
OPA	1,174,580	1,193,922	1,204,821	1,215,937	1,225,800	1,235,383	1,243,747	1,248,233	1,255,232	1,262,597
Total Texas	6,854,561	6,956,376	7,029,630	7,087,627	7,148,407	7,220,171	7,303,485	7,387,360	7,479,098	7,581,613
New Mexico										
Residential	845,381	861,706	869,009	875,821	883,079	893,542	906,021	920,404	936,823	953,648
Commercial & Industrial, Small	528,935	537,058	539,270	541,194	544,879	550,415	556,939	565,072	573,385	580,047
Commercial & Industrial, Large	75,359	74,520	73,908	73,388	72,906	72,438	71,976	71,517	71,059	70,602
Street Lighting	1,981	2,020	2,052	2,083	2,117	2,150	2,184	2,218	2,253	2,287
OPA	382,321	388,510	389,208	390,516	390,895	391,781	393,250	395,190	397,707	401,206
Total New Mexico	1,833,976	1,863,814	1,873,447	1,883,002	1,893,875	1,910,326	1,930,371	1,954,401	1,981,227	2,007,790
Company Use	13,815	13,940	14,065	14,192	14,319	14,448	14,578	14,709	14,842	14,975
RGEC	69,263	70,552	71,840	73,128	74,417	75,705	76,993	78,282	79,570	80,858
Total Native System	8,771,616	8,904,682	8,988,982	9,057,949	9,131,018	9,220,650	9,325,427	9,434,752	9,554,737	9,685,237

Attachment B-2: 2021 Energy Forecast by Jurisdiciton

Native System Energy	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Texas										
Residential	3,334,983	3,425,148	3,525,170	3,636,026	3,759,624	3,895,878	4,046,054	4,217,339	4,414,403	4,648,544
Commercial & Industrial, Small	2,045,129	2,054,225	2,064,580	2,075,693	2,087,123	2,098,034	2,109,568	2,121,481	2,135,189	2,151,857
Commercial & Industrial, Large	991,948	992,095	992,060	991,868	991,538	991,089	990,535	989,891	989,167	988,375
Street Lighting	46,133	46,630	47,109	47,569	48,017	48,461	48,888	49,300	49,698	50,084
OPA	1,268,335	1,274,223	1,280,435	1,286,279	1,291,280	1,295,889	1,301,542	1,307,228	1,313,637	1,322,537
Total Texas	7,686,529	7,792,320	7,909,355	8,037,435	8,177,583	8,329,351	8,496,587	8,685,239	8,902,094	9,161,398
New Mexico										
Residential	969,922	988,500	1,009,110	1,033,415	1,061,030	1,091,843	1,127,392	1,169,692	1,219,920	1,282,489
Commercial & Industrial, Small	589,680	598,960	609,083	619,444	629,020	639,480	651,488	664,333	677,512	689,964
Commercial & Industrial, Large	70,144	69,687	69,229	68,772	68,315	67,857	67,400	66,943	66,485	66,028
Street Lighting	2,323	2,360	2,397	2,435	2,473	2,511	2,549	2,586	2,623	2,659
OPA	403,305	406,275	409,566	413,428	417,445	421,124	424,534	427,835	431,174	435,500
Total New Mexico	2,035,375	2,065,782	2,099,386	2,137,494	2,178,283	2,222,815	2,273,362	2,331,388	2,397,713	2,476,639
Company Use	15,110	15,246	15,383	15,522	15,662	15,803	15,945	16,088	16,233	16,379
RGEC	82,147	83,435	84,723	86,012	87,300	88,589	89,877	91,165	92,454	93,742
Total Native System	9,819,161	9,956,784	10,108,847	10,276,463	10,458,828	10,656,557	10,875,771	11,123,881	11,408,494	11,748,158

Attachment B-3: 2021 Demand Forecast by Jurisdiction

Native System Demand	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Texas										
Residential	653	667	681	689	703	717	735	751	773	795
Commercial & Industrial, Small	479	484	486	485	488	489	491	492	496	499
Commercial & Industrial, Large	236	237	238	238	240	241	241	241	242	243
Street Lighting	10	10	10	10	11	11	11	11	11	11
OPA	285	290	293	295	298	301	303	304	307	309
Total Texas	1,662	1,688	1,708	1,718	1,740	1,759	1,782	1,799	1,830	1,858
New Mexico										
Residential	201	205	207	208	211	214	217	220	224	229
Commercial & Industrial, Small	126	128	128	129	130	132	133	135	137	139
Commercial & Industrial, Large	18	18	18	17	17	17	17	17	17	17
Street Lighting	0	0	0	0	1	1	1	1	1	1
OPA	91	92	93	93	93	94	94	94	95	96
Total New Mexico	436	443	446	448	452	457	462	466	475	482
Company Use	3	3	3	3	3	4	4	4	4	4
RGEC	19	20	20	20	21	21	22	22	23	23
Total Native System	2,121	2,155	2,177	2,190	2,216	2,240	2,269	2,292	2,331	2,367

Attachment B-3: 2021 Demand Forecast by Jurisdiction

Native System Demand	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Texas										
Residential	819	841	871	901	936	973	1,020	1,072	1,134	1,206
Commercial & Industrial, Small	502	504	510	515	520	524	532	539	548	558
Commercial & Industrial, Large	244	244	245	246	247	247	250	252	254	256
Street Lighting	11	11	12	12	12	12	12	13	13	13
OPA	312	313	316	319	322	324	328	332	337	343
Total Texas	1,888	1,913	1,954	1,992	2,036	2,079	2,142	2,208	2,286	2,376
New Mexico										
Residential	233	237	243	250	257	265	276	288	303	321
Commercial & Industrial, Small	142	144	147	150	153	155	159	164	168	173
Commercial & Industrial, Large	17	17	17	17	17	16	16	16	17	17
Street Lighting	1	1	1	1	1	1	1	1	1	1
OPA	97	97	99	100	101	102	104	105	107	109
Total New Mexico	489	496	506	517	528	540	556	574	595	620
Company Use	4	4	4	4	4	4	4	4	4	4
RGEC	23	24	24	25	25	25	26	27	27	28
Total Native System	2,404	2,436	2,488	2,538	2,593	2,648	2,728	2,813	2,913	3,028

Attachment B-4: Losses by Transmission and Distribution

Year	Secondary	Primary	Transmission	FERC	Losses (MW)
2021	130	4	4	0	138
2022	133	4	4	0	141
2023	135	4	4	0	144
2024	137	4	4	0	145
2025	139	4	4	0	148
2026	141	4	4	0	150
2027	144	4	5	0	153
2028	146	4	5	0	155
2029	149	4	5	0	159
2030	152	5	5	0	162
2031	155	5	5	0	165
2032	157	5	5	0	167
2033	160	5	5	0	171
2034	163	5	5	0	174
2035	166	5	5	0	177
2036	169	5	5	0	180
2037	173	5	5	0	184
2038	176	5	6	0	187
2039	179	5	6	0	191
2040	182	5	6	0	194

Attachment B-5: Typical Days Tables

Typical Days Report

New Mexico Residential

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	0.74	0.70	0.68	0.69	0.69	0.71	0.74	0.71
2:00	0.67	0.64	0.63	0.64	0.64	0.65	0.68	0.65
3:00	0.63	0.60	0.60	0.60	0.60	0.61	0.63	0.61
4:00	0.59	0.59	0.57	0.59	0.59	0.59	0.60	0.59
5:00	0.59	0.60	0.59	0.60	0.61	0.61	0.60	0.60
6:00	0.60	0.63	0.63	0.64	0.63	0.64	0.61	0.63
7:00	0.65	0.70	0.71	0.71	0.71	0.72	0.68	0.70
8:00	0.74	0.76	0.77	0.78	0.78	0.78	0.78	0.77
9:00	0.84	0.82	0.83	0.83	0.83	0.84	0.89	0.84
10:00	0.96	0.91	0.90	0.90	0.90	0.92	0.99	0.93
11:00	1.10	1.00	0.99	0.97	0.99	1.03	1.11	1.03
12:00	1.22	1.06	1.07	1.05	1.07	1.12	1.22	1.11
13:00	1.30	1.15	1.13	1.12	1.14	1.19	1.30	1.19
14:00	1.37	1.22	1.20	1.19	1.23	1.26	1.37	1.26
15:00	1.44	1.29	1.29	1.27	1.28	1.33	1.43	1.33
16:00	1.48	1.35	1.35	1.32	1.35	1.38	1.46	1.39
17:00	1.47	1.40	1.40	1.38	1.42	1.43	1.47	1.43
18:00	1.43	1.41	1.41	1.37	1.42	1.40	1.44	1.41
19:00	1.38	1.37	1.37	1.34	1.37	1.35	1.36	1.36
20:00	1.34	1.32	1.32	1.30	1.31	1.29	1.28	1.31
21:00	1.24	1.22	1.24	1.23	1.22	1.20	1.20	1.22
22:00	1.09	1.07	1.08	1.07	1.09	1.08	1.09	1.08
23:00	0.93	0.90	0.91	0.91	0.94	0.94	0.96	0.93
24:00	0.80	0.78	0.78	0.78	0.82	0.83	0.85	0.80
Average	1.03	0.98	0.98	0.97	0.99	1.00	1.03	0.99

Attachment B-5: Typical Days Tables

Typical Days Report

New Mexico Small General Service

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	1.52	1.48	1.50	1.52	1.53	1.53	1.54	1.52
2:00	1.48	1.45	1.47	1.49	1.50	1.50	1.51	1.49
3:00	1.47	1.44	1.46	1.47	1.47	1.48	1.49	1.47
4:00	1.47	1.46	1.47	1.48	1.48	1.49	1.49	1.48
5:00	1.47	1.49	1.50	1.51	1.52	1.52	1.50	1.50
6:00	1.45	1.55	1.56	1.57	1.57	1.59	1.51	1.54
7:00	1.43	1.68	1.71	1.72	1.72	1.73	1.52	1.64
8:00	1.41	1.95	2.01	2.01	2.00	2.00	1.58	1.85
9:00	1.53	2.25	2.36	2.35	2.34	2.31	1.77	2.13
10:00	1.68	2.47	2.60	2.60	2.58	2.55	1.95	2.35
11:00	1.81	2.58	2.70	2.70	2.70	2.65	2.05	2.46
12:00	1.91	2.61	2.73	2.76	2.76	2.71	2.12	2.51
13:00	1.94	2.66	2.77	2.82	2.81	2.76	2.14	2.56
14:00	1.93	2.73	2.88	2.88	2.89	2.83	2.15	2.61
15:00	1.89	2.74	2.88	2.88	2.89	2.80	2.14	2.60
16:00	1.87	2.59	2.72	2.73	2.75	2.65	2.12	2.49
17:00	1.85	2.27	2.36	2.39	2.44	2.35	2.05	2.25
18:00	1.85	2.06	2.15	2.15	2.25	2.17	2.01	2.09
19:00	1.86	1.99	2.04	2.08	2.18	2.09	1.98	2.03
20:00	1.84	1.91	1.96	2.02	2.07	2.03	1.95	1.97
21:00	1.78	1.81	1.85	1.90	1.91	1.92	1.87	1.86
22:00	1.69	1.72	1.74	1.77	1.77	1.82	1.78	1.76
23:00	1.58	1.63	1.63	1.66	1.65	1.70	1.67	1.65
24:00	1.51	1.55	1.56	1.58	1.58	1.61	1.58	1.57
Average	1.68	2.00	2.07	2.08	2.10	2.07	1.81	1.97

Attachment B-5: Typical Days Tables

Typical Days Report

New Mexico General Service

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	41.04	40.17	45.49	46.00	46.05	45.97	44.28	44.16
2:00	40.21	39.69	43.91	44.31	44.54	44.50	42.85	42.87
3:00	39.48	39.55	42.84	43.22	43.45	43.33	41.70	41.95
4:00	39.23	41.17	43.46	43.94	43.79	43.58	41.83	42.44
5:00	39.60	45.04	46.79	47.26	47.05	46.73	43.43	45.14
6:00	40.66	49.45	50.95	51.25	51.05	50.23	45.45	48.45
7:00	42.05	54.06	56.08	56.21	55.84	54.82	47.19	52.34
8:00	43.83	59.38	61.15	61.03	60.74	59.34	49.33	56.42
9:00	46.18	63.31	64.80	64.73	64.34	63.08	52.09	59.82
10:00	48.16	66.09	67.63	67.69	67.25	65.85	54.39	62.46
11:00	49.80	67.80	69.18	68.91	68.78	67.40	56.01	64.01
12:00	51.31	68.90	69.99	69.44	69.50	68.09	57.01	64.92
13:00	52.51	69.88	71.03	70.44	70.46	69.15	57.65	65.90
14:00	53.33	70.50	71.91	70.98	70.91	69.80	58.36	66.56
15:00	53.67	69.48	70.84	70.00	69.90	68.85	58.57	65.92
16:00	53.42	67.69	68.97	68.22	68.39	67.14	58.02	64.57
17:00	52.14	64.43	65.49	65.09	65.39	63.91	56.60	61.88
18:00	51.22	61.34	62.64	62.35	62.68	60.88	55.34	59.51
19:00	50.43	59.91	61.33	61.12	60.85	59.33	54.46	58.22
20:00	49.39	58.66	60.19	59.84	59.49	58.35	53.41	57.06
21:00	47.23	55.77	57.17	56.79	56.58	55.25	50.32	54.17
22:00	45.01	53.22	54.12	53.86	53.73	52.28	47.32	51.38
23:00	42.54	49.96	50.61	50.47	50.33	49.44	44.65	48.30
24:00	41.02	47.42	48.22	47.99	47.85	46.46	42.41	45.92
Average	46.39	56.79	58.53	58.38	58.29	57.23	50.53	55.18

Attachment B-5: Typical Days Tables

Typical Days Report

New Mexico City and County

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	7.11	7.13	7.16	7.28	7.27	7.27	7.18	7.20
2:00	7.07	7.11	7.12	7.25	7.25	7.25	7.15	7.17
3:00	7.03	7.10	7.12	7.21	7.22	7.19	7.12	7.14
4:00	7.06	7.43	7.43	7.49	7.47	7.47	7.15	7.36
5:00	7.23	9.12	8.87	8.84	8.82	8.79	7.34	8.43
6:00	7.22	10.55	10.27	10.10	10.09	9.83	7.40	9.36
7:00	6.95	11.61	11.40	11.10	11.14	10.84	7.20	10.04
8:00	6.77	12.24	12.19	11.69	11.92	11.52	6.99	10.48
9:00	6.82	12.88	12.87	12.29	12.64	12.13	7.05	10.96
10:00	6.89	13.15	13.18	12.70	12.99	12.43	7.12	11.22
11:00	6.95	13.30	13.44	13.04	13.26	12.71	7.17	11.42
12:00	7.00	13.46	13.65	13.20	13.49	12.86	7.25	11.57
13:00	7.16	13.60	13.79	13.40	13.64	12.97	7.39	11.72
14:00	7.30	13.54	13.78	13.29	13.53	12.91	7.51	11.70
15:00	7.33	12.77	12.99	12.48	12.75	12.08	7.50	11.14
16:00	7.40	10.97	11.21	10.87	11.03	10.58	7.58	9.96
17:00	7.48	9.90	10.06	9.97	10.02	9.71	7.65	9.26
18:00	7.57	9.25	9.40	9.39	9.41	9.10	7.64	8.83
19:00	7.74	8.74	8.89	8.95	8.97	8.70	7.77	8.54
20:00	7.86	8.36	8.56	8.59	8.58	8.39	7.89	8.32
21:00	7.82	8.15	8.33	8.35	8.34	8.18	7.82	8.14
22:00	7.45	7.65	7.76	7.81	7.80	7.65	7.45	7.65
23:00	7.21	7.28	7.37	7.40	7.39	7.31	7.19	7.31
24:00	7.14	7.17	7.28	7.29	7.29	7.21	7.13	7.21
Average	7.23	10.10	10.17	10.00	10.10	9.79	7.36	9.26

Attachment B-5: Typical Days Tables

Typical Days Report

New Mexico Large Power

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	18,174.14	17,679.87	19,139.05	19,198.51	19,061.19	19,152.69	18,721.54	18,735.74
2:00	18,107.66	17,656.49	19,058.19	19,050.99	18,953.93	19,122.52	18,654.25	18,659.60
3:00	18,103.46	17,710.23	19,014.07	19,050.74	18,927.05	19,002.28	18,593.29	18,630.70
4:00	18,049.97	17,919.02	19,210.67	19,266.70	19,072.37	19,132.03	18,630.18	18,756.69
5:00	18,078.75	18,291.89	19,464.28	19,595.23	19,312.50	19,283.71	18,677.03	18,960.34
6:00	17,811.16	18,327.42	19,378.31	19,572.53	19,289.22	19,195.86	18,410.57	18,858.16
7:00	17,248.57	18,305.14	19,339.75	19,405.48	19,115.46	18,854.66	17,944.84	18,605.58
8:00	16,493.88	18,125.57	19,056.76	19,052.06	18,907.19	18,377.68	17,204.56	18,178.36
9:00	16,083.69	17,994.93	18,860.04	18,915.15	18,906.14	18,280.10	16,936.95	18,001.71
10:00	15,889.90	18,152.75	18,939.24	18,928.52	18,895.31	18,226.60	16,975.05	18,006.03
11:00	15,906.17	18,335.61	19,033.99	18,959.46	18,926.90	18,265.00	17,082.53	18,077.56
12:00	16,169.00	18,440.46	19,021.08	19,042.42	18,992.84	18,245.11	16,992.13	18,133.86
13:00	16,391.79	18,693.63	19,266.64	19,056.29	19,072.73	18,360.85	17,114.50	18,283.78
14:00	16,608.45	18,970.86	19,393.13	19,097.04	19,175.87	18,456.23	17,254.48	18,426.20
15:00	16,844.94	19,014.43	19,544.68	19,220.73	19,197.99	18,581.01	17,519.44	18,564.01
16:00	17,155.20	19,066.58	19,413.78	19,202.37	19,145.29	18,777.03	17,918.41	18,671.14
17:00	17,675.47	19,299.88	19,698.42	19,401.59	19,447.36	19,205.24	18,375.83	19,017.07
18:00	18,218.71	19,701.66	19,971.34	19,702.19	19,849.59	19,665.41	18,903.02	19,432.16
19:00	18,373.58	19,988.48	20,207.90	19,958.56	20,103.69	19,753.42	19,151.95	19,650.32
20:00	18,409.37	20,063.12	20,237.79	20,024.89	20,045.68	19,768.85	19,153.53	19,673.88
21:00	18,247.31	19,843.47	19,993.30	19,757.52	19,848.10	19,600.87	18,957.75	19,465.90
22:00	18,008.02	19,607.18	19,756.22	19,502.87	19,533.17	19,266.67	18,638.68	19,189.35
23:00	17,751.86	19,398.40	19,439.94	19,227.68	19,252.63	18,908.83	18,397.28	18,912.74
24:00	17,665.52	19,230.99	19,365.15	19,086.26	19,214.52	18,808.62	18,289.69	18,810.55
Average	17,394.44	18,742.42	19,408.49	19,303.16	19,260.28	18,928.98	18,104.06	18,737.56

Typical Days Report

Texas Residential

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	0.66	0.63	0.62	0.62	0.63	0.65	0.66	0.64
2:00	0.61	0.59	0.57	0.57	0.58	0.60	0.61	0.59
3:00	0.57	0.56	0.54	0.55	0.56	0.56	0.58	0.56
4:00	0.54	0.55	0.53	0.54	0.54	0.55	0.56	0.54
5:00	0.53	0.54	0.53	0.53	0.54	0.54	0.55	0.54
6:00	0.53	0.56	0.56	0.57	0.57	0.57	0.54	0.56
7:00	0.56	0.62	0.61	0.62	0.63	0.63	0.60	0.61
8:00	0.64	0.66	0.67	0.68	0.67	0.68	0.69	0.67
9:00	0.76	0.74	0.75	0.76	0.76	0.77	0.80	0.76
10:00	0.90	0.84	0.83	0.84	0.85	0.84	0.91	0.86
11:00	1.02	0.96	0.93	0.94	0.96	0.95	1.03	0.97
12:00	1.13	1.07	1.03	1.04	1.06	1.05	1.13	1.07
13:00	1.22	1.15	1.11	1.12	1.15	1.13	1.23	1.16
14:00	1.29	1.22	1.19	1.18	1.21	1.21	1.29	1.23
15:00	1.36	1.30	1.27	1.26	1.28	1.29	1.36	1.30
16:00	1.39	1.34	1.32	1.31	1.34	1.33	1.39	1.35
17:00	1.37	1.34	1.35	1.34	1.36	1.33	1.37	1.35
18:00	1.33	1.31	1.32	1.31	1.33	1.31	1.31	1.32
19:00	1.27	1.26	1.27	1.25	1.27	1.24	1.24	1.26
20:00	1.21	1.20	1.21	1.20	1.22	1.18	1.18	1.20
21:00	1.14	1.10	1.12	1.11	1.14	1.09	1.09	1.11
22:00	1.00	0.96	0.97	0.96	1.00	0.97	0.98	0.98
23:00	0.85	0.82	0.82	0.82	0.86	0.85	0.86	0.84
24:00	0.71	0.70	0.70	0.70	0.73	0.74	0.75	0.72
Average	0.94	0.92	0.91	0.91	0.93	0.92	0.95	0.92

Attachment B-5: Typical Days Tables

Typical Days Report

Texas Small General Service

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	0.89	0.89	0.91	0.89	0.91	0.89	0.90	0.90
2:00	0.83	0.81	0.83	0.82	0.83	0.83	0.84	0.83
3:00	0.79	0.79	0.81	0.78	0.81	0.80	0.79	0.80
4:00	0.74	0.75	0.77	0.74	0.77	0.75	0.75	0.75
5:00	0.73	0.74	0.75	0.75	0.75	0.75	0.74	0.75
6:00	0.70	0.76	0.76	0.75	0.77	0.75	0.73	0.74
7:00	0.64	0.80	0.80	0.79	0.79	0.79	0.70	0.76
8:00	0.63	0.90	0.90	0.88	0.88	0.90	0.74	0.83
9:00	0.68	1.08	1.10	1.07	1.08	1.09	0.85	0.99
10:00	0.75	1.24	1.26	1.24	1.26	1.28	0.98	1.15
11:00	0.80	1.32	1.36	1.34	1.37	1.39	1.08	1.24
12:00	0.84	1.36	1.42	1.39	1.42	1.43	1.11	1.28
13:00	0.85	1.40	1.46	1.42	1.45	1.46	1.12	1.31
14:00	0.86	1.43	1.48	1.46	1.47	1.48	1.13	1.33
15:00	0.88	1.42	1.48	1.44	1.47	1.45	1.10	1.32
16:00	0.89	1.40	1.45	1.41	1.43	1.41	1.08	1.29
17:00	0.90	1.29	1.33	1.31	1.34	1.29	1.05	1.22
18:00	0.97	1.21	1.24	1.25	1.27	1.23	1.07	1.18
19:00	1.02	1.16	1.18	1.20	1.21	1.18	1.09	1.15
20:00	1.05	1.14	1.14	1.16	1.16	1.15	1.09	1.13
21:00	1.03	1.09	1.09	1.10	1.10	1.10	1.06	1.08
22:00	1.00	1.04	1.03	1.04	1.04	1.05	1.02	1.03
23:00	0.95	0.99	0.98	0.99	0.99	0.99	0.98	0.98
24:00	0.93	0.96	0.93	0.96	0.94	0.94	0.93	0.94
Average	0.85	1.08	1.10	1.09	1.10	1.10	0.95	1.04

Attachment B-5: Typical Days Tables

Typical Days Report

Texas General Service

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	15.57	15.15	15.65	15.65	15.87	15.92	16.04	15.69
2:00	14.73	14.69	15.02	14.97	15.12	15.25	15.24	15.00
3:00	14.24	14.65	14.83	14.77	14.87	15.01	14.79	14.74
4:00	14.02	15.12	15.29	15.25	15.29	15.49	14.79	15.04
5:00	14.17	16.70	16.75	16.74	16.75	16.71	15.53	16.20
6:00	14.26	18.27	18.81	18.69	18.75	18.59	16.70	17.73
7:00	14.60	20.50	21.19	20.96	21.03	20.74	17.45	19.50
8:00	15.56	22.89	23.46	23.22	23.38	23.05	18.51	21.45
9:00	17.19	25.24	25.80	25.61	25.85	25.42	20.16	23.62
10:00	18.80	27.09	27.67	27.48	27.78	27.35	21.79	25.43
11:00	20.26	28.49	29.03	28.81	29.04	28.63	22.92	26.75
12:00	21.08	29.16	29.70	29.59	29.72	29.30	23.52	27.45
13:00	21.54	29.61	30.04	29.91	30.01	29.54	23.71	27.78
14:00	21.91	29.97	30.27	30.22	30.37	29.71	23.94	28.07
15:00	22.20	29.86	30.17	30.14	30.24	29.58	24.03	28.04
16:00	22.32	28.73	29.13	29.15	29.14	28.53	23.92	27.29
17:00	22.11	26.79	27.08	27.12	27.10	26.70	23.67	25.80
18:00	22.08	25.38	25.76	25.79	25.76	25.52	23.63	24.85
19:00	21.62	24.29	24.67	24.93	24.72	24.69	23.30	24.03
20:00	21.03	23.14	23.38	23.75	23.48	23.49	22.35	22.95
21:00	19.62	21.43	21.74	21.99	21.83	21.98	21.05	21.38
22:00	18.28	19.45	19.73	19.87	19.89	20.15	19.45	19.55
23:00	16.92	17.76	18.03	18.17	18.18	18.57	17.83	17.92
24:00	16.10	16.69	16.85	16.95	17.05	17.27	16.71	16.80
Average	18.34	22.54	22.92	22.91	22.97	22.79	20.04	21.79

Attachment B-5: Typical Days Tables

Typical Days Report

Texas Large Power

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	66,562.31	66,221.73	73,182.50	73,454.62	73,028.48	72,650.26	71,397.00	70,945.43
2:00	66,005.17	65,875.46	72,812.63	72,845.67	72,502.26	72,573.89	70,858.73	70,508.16
3:00	65,678.02	65,827.35	72,487.50	72,441.24	72,313.14	72,148.92	70,300.01	70,182.94
4:00	65,617.65	67,100.05	73,537.13	73,244.27	73,315.59	73,150.46	70,288.26	70,906.39
5:00	65,701.13	70,065.45	76,067.79	75,473.65	75,871.79	75,407.50	71,019.32	72,816.64
6:00	66,025.13	73,835.95	79,685.81	78,481.64	78,818.74	78,116.05	71,692.64	75,255.22
7:00	66,100.67	77,487.95	82,412.56	80,736.50	81,153.65	79,952.68	71,536.53	77,075.62
8:00	66,830.34	81,263.28	84,963.52	83,216.72	83,563.36	82,398.20	72,583.49	79,282.41
9:00	68,191.32	84,309.26	87,443.85	85,428.78	85,947.33	84,831.37	74,396.60	81,529.78
10:00	69,785.76	86,509.29	89,319.54	87,103.74	87,704.87	86,485.13	75,960.33	83,289.56
11:00	71,232.55	88,372.13	90,300.00	88,427.41	88,849.89	87,713.13	77,289.21	84,619.84
12:00	72,311.21	88,506.47	89,842.34	88,009.39	88,701.68	87,398.61	77,531.62	84,634.92
13:00	73,126.05	89,340.10	90,497.69	88,882.59	89,422.19	88,178.71	77,853.37	85,349.57
14:00	73,611.25	89,810.81	91,231.86	89,559.00	89,500.06	88,815.54	77,829.47	85,785.99
15:00	73,845.75	89,516.16	90,826.21	89,155.63	88,915.17	88,416.22	77,712.20	85,503.31
16:00	73,595.32	88,719.66	89,924.57	88,258.04	87,777.28	86,866.50	77,319.21	84,655.70
17:00	72,927.22	86,890.26	87,941.14	86,411.94	86,037.58	85,023.86	76,604.54	83,136.47
18:00	71,836.87	85,413.20	86,357.17	85,158.09	84,670.09	83,887.29	75,988.07	81,918.00
19:00	70,562.26	83,132.10	84,211.12	83,038.47	82,446.67	81,753.79	74,601.71	79,978.92
20:00	69,518.88	81,218.45	82,305.91	81,487.61	80,607.32	80,068.85	73,179.29	78,355.69
21:00	68,315.07	79,448.22	80,399.20	79,642.16	78,855.25	78,165.61	71,604.24	76,647.11
22:00	67,519.25	77,336.63	78,191.68	77,575.03	76,811.01	75,746.45	70,102.36	74,767.95
23:00	66,747.24	75,278.41	76,119.44	75,395.46	74,980.67	73,770.35	68,461.65	72,976.90
24:00	66,061.83	73,785.64	74,656.75	73,897.59	73,501.07	72,185.28	67,236.33	71,629.16
Average	69,071.18	79,802.67	82,696.58	81,555.22	81,470.63	80,647.95	73,472.76	78,405.47

Attachment B-5: Typical Days Tables

Typical Days Report

Texas City and County

For the year ending December 31, 2020

Time	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Average
1:00	17.38	18.76	18.05	18.17	18.12	18.02	17.46	17.99
2:00	17.28	19.96	18.76	18.77	18.67	18.48	17.42	18.48
3:00	17.24	21.29	19.55	19.61	19.51	19.27	17.39	19.13
4:00	17.33	23.32	21.95	21.96	21.94	21.64	17.53	20.82
5:00	17.29	26.41	25.44	25.21	25.26	24.92	17.66	23.18
6:00	16.96	30.21	29.64	29.30	29.40	28.74	17.56	25.99
7:00	16.43	33.58	33.45	32.77	33.13	32.02	17.62	28.45
8:00	16.22	36.44	36.75	35.72	36.34	34.89	17.80	30.62
9:00	16.49	38.47	38.89	37.77	38.64	37.00	18.16	32.24
10:00	16.87	39.53	39.98	39.06	39.79	38.05	18.42	33.14
11:00	16.95	40.33	40.81	40.12	40.63	38.92	18.51	33.79
12:00	17.23	40.65	41.26	40.61	41.07	39.30	18.56	34.14
13:00	17.43	40.81	41.56	40.83	41.23	39.39	18.62	34.30
14:00	17.54	40.28	41.10	40.26	40.82	38.80	18.54	33.94
15:00	17.39	38.83	39.72	38.82	39.43	37.64	18.28	32.91
16:00	17.61	34.35	35.28	34.58	35.07	33.32	18.12	29.79
17:00	17.77	27.87	28.73	28.17	28.51	27.33	17.98	25.21
18:00	18.04	23.62	24.45	24.09	24.28	23.45	18.15	22.31
19:00	18.54	22.28	23.02	22.70	22.75	22.21	18.57	21.45
20:00	18.86	21.42	21.95	21.72	21.79	21.52	18.78	20.87
21:00	18.61	20.40	20.78	20.65	20.74	20.49	18.53	20.03
22:00	18.40	19.39	19.74	19.56	19.57	19.29	18.13	19.16
23:00	18.24	18.58	18.91	18.73	18.70	18.29	17.81	18.47
24:00	18.36	18.08	18.33	18.25	18.10	17.63	17.55	18.04
Average	17.52	28.95	29.09	28.64	28.90	27.93	18.05	25.60

Attachment C-1: Transmission Facilities
TABLE 1. Existing EPE Transmission Lines 115 kV and Above

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
AMRAD	EMPIRE	345	1	400	400	125.10	TX	NM
CALIENTE	AMRAD	345	1	785	785	56.7	TX	NM
CALIENTE	PICANTE	345	1	788	788	7.3	TX	TX
EMPIRE	EDDY	345	1	836	836	0.5	NM	NM
HIDALGO	GREENLEE	345	1	765	765	60.0	NM	AZ
LUNA	AFTON	345	1	921	987	57.3	NM	NM
LUNA	DIABLO	345	1	939	939	84.9	NM	NM
LUNA	HIDALGO	345	1	659	659	50.5	NM	NM
MACHO SPRINGS	LUNA	345	1	1031	1390	24.9	NM	NM
MACHO SPRINGS	SPRINGERVILLE	345	1	728	728	201.4	NM	AZ
NEWMAN	ARROYO	345	1	700	700	30.3	TX	NM
NEWMAN	AFTON	345	1	924	1028	29.9	TX	NM
PICANTE	NEWMAN	345	1	786	786	16.2	TX	TX
WESTMESA	ARROYO	345	1	680	680	201.8	NM	NM
MIMBRES TAP	AIRPORT	115	1	123	163	2.7	NM	NM
AMRAD	HOLLOMAN	115	1	121	121	22.5	NM	NM
ANTHONY	ARROYO	115	1	114	114	24.4	NM	NM
ANTHONY	BORDER STEEL	115	1	165	220	5.2	NM	TX
ANTHONY	SALOPEK	115	1	165	220	17.3	NM	NM
ANTHONY	NEWMAN	115	1	165	212	12.3	NM	TX
ANTHONY	NUWAY	115	1	165	220	6.6	NM	TX
ASCARATE	TROWBRIDGE	115	1	181	181	0.5	TX	TX
ASCARATE	COPPER	115	1	185	246	1.4	TX	TX
ASCARATE	JUAREZ	115	1	185	247	2.4	TX	
AUSTIN	MARLOW	115	1	227	227	1.2	TX	TX
BIGGS	BLISS INDUSTRIAL	115	1	185	246	2.2	TX	TX
BLISS INDUSTRIAL	LIBERTY	115	1	185	246	2.2	TX	TX
BUTTERFIELD	FT. BLISS	115	1	135	180	1.9	TX	TX
CALIENTE	DIAMOND HEAD	115	1	185	247	6.1	TX	TX
CALIENTE	MPS	115	1	69	87	8.5	TX	TX
CALIENTE	MPS	115	2	268	332	3.1	TX	TX
CALIENTE	MPS	115	3	268	332	3.1	TX	TX
CALIENTE	VISTA	115	1	166	221	6.6	TX	TX
CHAPARRAL	ORO GRANDE	115	1	135	165	35.4	NM	NM
COPPER	PENDALE	115	1	185	246	5.1	TX	TX

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
COYOTE	RGC_DELL CITY	115	1	23	23	10.8	TX	TX
COYOTE	MONTWOOD	115	1	185	246	7.9	TX	NM
CROMO	RIO GRANDE	115	1	135	180	0.9	TX	TX
DIABLO	RIO GRANDE	115	1	332	441	2.9	NM	TX
DIABLO	RIO GRANDE	115	2	332	441	2.9	NM	NM
DIABLO	JUAREZ	115	1	185	247	2.3	NM	
DIAMOND HEAD	LANE	115	1	185	247	2.8	TX	TX
DURAZNO	ASCARATE	115	1	185	246	3.3	TX	NM
DYER	SHEARMAN	115	1	135	180	9.6	TX	TX
DYER	AUSTIN	115	1	185	246	2.1	TX	TX
EXECUTIVE	RIO GRANDE	115	1	271	359	2.9	TX	TX
FT. BLISS	AUSTIN	115	1	135	180	1.8	TX	TX
GLOBAL REACH	VISTA	115	1	329	329	3.0	TX	TX
HATCH	JORNADA	115	1	45	45	33.4	NM	NM
JORNADA	ARROYO	115	1	79	79	4.9	NM	NM
LANE	WRANGLER	115	1	165	220	1.0	TX	TX
LAS CRUCES	ARROYO	115	1	165	220	4.1	NM	NM
LAS CRUCES	SALOPEK	115	1	165	220	5.0	NM	NM
LEO EAST	DYER	115	1	185	246	3.8	TX	TX
LEO EAST	MILAGRO	115	1	185	246	4.4	TX	TX
LIBERTY	GLOBAL REACH	115	1	185	246	2.6	TX	TX
MAR	LARGO	115	1	29	29	11.4	NM	NM
MARLOW	TROWBRIDGE	115	1	181	181	1.1	TX	TX
MESA	AUSTIN	115	1	165	220	6.1	TX	TX
MESA	RIO GRANDE	115	1	268	268	2.3	TX	NM
MILAGRO	NEWMAN	115	1	185	246	6.3	TX	TX
MONTWOOD	CALIENTE	115	1	185	246	5.0	TX	TX
MPS	COYOTE	115	1	249	387	3.1	TX	TX
MPS	MONTWOOD	115	1	249	387	7.0	TX	TX
NEWMAN	CHAPARRAL	115	1	135	180	2.9	TX	NM
NEWMAN	BUTTERFIELD	115	1	135	280	16.7	TX	TX
NEWMAN	SHEARMAN	115	1	135	280	7.3	TX	TX
NEWMAN	PIPELINE	115	1	185	246	9.8	TX	TX
NEWMAN	PICANTE	115	1	185	246	13.6	TX	TX
NUWAY	MONTOYA	115	1	165	220	3.6	TX	TX
ORO GRANDE	AMRAD	115	1	135	165	12.3	NM	NM
ORO GRANDE	WHITE SANDS	115	1	75	75	22.8	NM	NM
PATRIOT	NEWMAN	115	1	135	180	1.5	TX	TX
PATRIOT	CROMO	115	1	135	180	18.4	TX	TX
PELICANO	HORIZON	115	1	185	246	6.7	TX	TX

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
PELICANO	MONTWOOD	115	1	185	246	3.8	TX	TX
PENDALE	LANE	115	1	185	246	1.5	TX	TX
PICANTE	GLOBAL REACH	115	1	185	246	6.0	TX	TX
PICANTE	BIGGS	115	1	185	246	2.3	TX	TX
PIPELINE	BIGGS	115	1	135	180	13.6	TX	TX
RIO GRANDE	RIPLEY	115	1	165	220	3.0	NM	TX
RIPLEY	THORN	115	1	135	180	1.9	TX	TX
SALOPEK	ARROYO	115	1	135	180	10.7	NM	NM
SANTA TERESA	MONTOYA	115	1	185	246	7.4	NM	TX
SANTA TERESA	DIABLO	115	1	169	225	8.9	NM	NM
SCOTSDALE	VISTA	115	1	135	180	5.2	TX	TX
SOL	LANE	115	1	135	180	2.1	TX	TX
SOL	VISTA	115	1	185	246	2.0	TX	TX
SPARKS	HORIZON	115	1	185	246	3.8	TX	TX
SUNSET NORTH	DURAZNO	115	1	185	246	4.6	TX	TX
SUNSET NORTH	EXECUTIVE	115	1	271	359	2.3	TX	TX
THORN	MONTOYA	115	1	135	180	3.0	TX	TX
WRANGLER	SPARKS	115	1	185	246	4.0	TX	TX

- "Internal" refers to lines within EPE's Balancing Area including lines connecting EPE to neighboring utilities, however, not including line segments partially owned by EPE external to EPE's control area.
- Some transmission lines were identified to be capacity limited by smaller jumpers connected at the substations. The line ratings reflected in the above table are based on-line jumper upgrade assumptions.
- The ratings are generally based on conductor thermal capacities but may be derated due to sag limitations or other factors.
- RGC_DC is Rio Grande Electric Cooperative, Dell City.
- Emerg is short for Emergency

TABLE 2. Existing 115 kV EPE Substation Transformers

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal	Emergency	
		MVA	MVA	
AIRPORT	115/23.9	33.6	37.6	NM
AMRAD	115/24.9	8.5	9.5	NM
ANTHONY T1	115/23.9	33.6	37.6	NM
ANTHONY T2	115/23.9	56.0	62.7	NM
ARROYO T2	115/23.9	33.6	37.6	NM
ARROYO T4	115/23.9	33.6	37.6	NM
ASCARATE T4	115/69	112	128.8	TX
ASCARATE T5	115/69	112	128.8	TX
AUSTIN T1	115/13.8	50.0	56.0	TX
AUSTIN T2	115/13.8	56.0	62.7	TX
BORDER STEEL 115 T1	115/13.8	39.2	43.9	TX
BORDER STEEL 115 T2	115/13.8	39.2	43.9	TX
BUTTERFIELD T1	115/13.8	30.0	33.6	TX
BUTTERFIELD T2	115/13.8	30.0	33.6	TX
CALIENTE T3	115/13.8	33.6	37.6	TX
CENTRAL TEMP T1	115/13.8	33.6	37.6	TX
CHAPARRAL T1	115/13.8	33.6	37.6	NM
CHAPARRAL T2	115/13.8	33.6	37.6	NM
COPPER T1	115/13.8	30.0	33.6	TX
COPPER GEN T2	13.8/115	84.0	94.1	TX
COX T2	115/69	56.0	64.4	NM
COYOTE T1	115/13.8	30.0	33.6	TX
CROMO T1	115/13.8	30.0	33.6	TX
CROMO T2	115/13.8	33.6	37.6	TX
DIAMOND HEAD T1	115/13.8	33.6	37.6	TX
DURAZNO T1	115/13.8	33.6	37.6	TX
DYER T3	115/69	112	128.8	TX
EMRLD T1	115/13.8	12.5	14.0	NM
EXECUTIVE T1	115/13.8	56.0	62.7	TX
EXECUTIVE T2	115/13.8	56.0	62.7	TX
FT. BLISS T1	115/13.8	56.0	62.7	TX
FT. BLISS T2	115/13.2	28.0	31.4	TX
GLOBAL REACH T1	115/13.8	33.6	37.6	TX
GLOBAL REACH T2	115/13.8	56.0	62.7	TX

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal	Emergency	
		MVA	MVA	
HATCH T1	115/24.9	30.0	33.6	NM
HORIZON T1	115/13.8	33.6	37.6	TX
JORNADA T1	115/23.9	33.6	37.6	NM
JORNADA T2	115/23.9	56.0	62.7	NM
LANE T1	115/69	100	115	TX
LANE T2	115/13.8	30.0	33.6	TX
LAS CRUCES T1	115/23.9	67.2	75.3	NM
LAS CRUCES T2	115/23.9	67.2	75.3	NM
LEO EAST T1	115/13.8	33.6	37.6	TX
LEO EAST T2	115/13.8	33.6	37.6	TX
MAR T1	115/4.2	11.2	12.5	NM
MESA T1	115/13.8	30.0	33.6	TX
MESA T2	115/13.8	33.6	37.6	TX
MILAGRO T1	115/13.8	33.6	37.6	TX
MILAGRO T2	115/13.8	33.6	37.6	TX
MILAGRO T3	115/13.8	33.6	37.6	TX
MONTOYA T1	115/24.9	33.6	37.6	TX
MONTOYA T2	115/23.9	56.0	62.7	TX
MONTOYA T3	115/23.9	56.0	62.7	TX
MONTWOOD T1	115/23.9	56.0	62.7	TX
MONTWOOD T3	115/23.9	56.0	62.7	TX
MPS T1	13.8/115	140.0	156.8	TX
MPS T2	13.8/115	140.0	156.8	TX
MPS T3	13.8/115	140.0	156.8	TX
MPS T4	13.8/115	140.0	156.8	TX
NEWMAN G1(T2)	13.8/115	125.4	140.5	TX
NEWMAN G2 (T6)	13.8/115	125.4	140.5	TX
NEWMAN G3 (T8)	13.8/115	125.4	140.5	TX
NEWMAN 4G1 (T11)	13.8/115	125.0	140.0	TX
NEWMAN 4G2 (T9)	13.8/115	125.0	140.0	TX
NEWMAN 4S1 (T13)	13.8/115	125.0	140.0	TX
NEWMAN 5G1 (T15)	13.8/115	130.0	145.6	TX
NEWMAN 5G2 (T16)	13.8/115	130.0	145.6	TX
NEWMAN 5S1 (T14)	13.8/115	175.0	196	TX
NUWAY T1	115/23.9	56.0	62.7	TX
NUWAY T2	115/23.9	56.0	62.7	TX

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal	Emergency	
		MVA	MVA	
PATRIOT T1	115/13.8	33.6	37.6	TX
PELICANO T1	115/23.9	56.0	62.7	TX
PELICANO T2	115/23.9	56.0	62.7	TX
PENDALE T1	115/13.8	33.6	37.6	TX
PENDALE T2	115/13.8	56.0	62.7	TX
PICACHO T1	115/24.9	56.0	62.7	NM
REDEYE T1	115/13.8	14.0	15.7	NM
RIO GRANDE T1	115/69	112	128.8	NM
RIO GRANDE T2	115/69	112	128.8	NM
RIO GRANDE G8 (T7)	17.5/115	168.0	188.2	NM
RIO GRANDE G9 (T17)	13.8/115	132.0	147.8	NM
RIPLEY T1	115/13.8	33.6	37.6	TX
RIPLEY T2	115/13.8	56.0	62.7	TX
SALOPEK T1	115/24.9	28.0	31.4	NM
SALOPEK T2	115/24.9	28.0	31.4	NM
SALOPEK T3	115/24.9	28.0	31.4	NM
SANTA TERESA T1	115/23.9	33.6	37.6	NM
SANTA TERESA T2	115/23.9	33.6	37.6	NM
SCOTSDALE T1	115/69	112	128.8	TX
SCOTSDALE T4	115/13.8	56.0	62.7	TX
SCOTSDALE T5	115/13.8	56.0	62.7	TX
SHEARMAN T1	115/13.8	30.0	33.6	TX
SOL T1	115/13.8	33.6	37.6	TX
SOL T2	115/13.8	30.0	33.6	TX
SPARKS T1	115/13.8	33.6	37.6	TX
SPARKS T2	115/13.8	56.0	62.7	TX
SPARKS T3	115/69	100	115	TX
SUNSET NORTH T1	115/13.8	33.6	37.6	TX
SUNSET NORTH T2	115/13.8	33.6	37.6	TX
SUNSET NORTH T3	115/69	112	128.8	TX
TALAVERA TEMP T1	115/23.9	16.5	18.5	NM
THORN T1	115/13.8	33.6	37.6	TX
THORN T2	115/13.8	33.6	37.6	TX
TRIUMPH TEMP T1	115/23.9	33.6	37.6	TX
VISTA T1	115/13.8	30.0	33.6	TX
VISTA T2	115/13.8	30.0	33.6	TX

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING		State
		Normal	Emergency	
		MVA	MVA	
WHITE SANDS T1	115/13.8	30.0	33.6	NM
WRANGLER T1	115/13.8	50.0	56.0	TX

Attachment C-2: Existing Units Operating Characteristics

Capacity Factor (%)

Resources	2021	2024	2025	2027	2031	2035	2040	2045
Newman 1	2%	0%	0%	0%	0%	0%	0%	0%
Newman 2	1%	0%	0%	0%	0%	0%	0%	0%
Newman 3	10%	3%	0%	1%	0%	0%	0%	0%
Newman 4	14%	5%	2%	3%	1%	0%	0%	0%
Newman 5	64%	54%	38%	41%	44%	40%	41%	47%
Newman 6	0%	12%	7%	8%	6%	3%	4%	6%
Copper	2%	0%	0%	0%	0%	0%	0%	0%
Montana 1	26%	29%	20%	21%	20%	11%	19%	23%
Montana 2	26%	28%	19%	21%	21%	14%	23%	24%
Montana 3	17%	17%	13%	14%	12%	5%	11%	16%
Montana 4	50%	42%	30%	32%	28%	23%	28%	28%
Rio Grande 7	0%	0%	0%	0%	0%	0%	0%	0%
Rio Grande 8	3%	1%	0%	0%	0%	0%	0%	0%
Rio Grande 9	13%	5%	2%	3%	3%	0%	0%	2%
Gas Peaker	0%	0%	0%	0%	0%	3%	3%	5%
Palo Verde 1	94%	94%	94%	94%	94%	94%	94%	94%
Palo Verde 2	94%	94%	94%	94%	94%	94%	94%	94%
Palo Verde 3	94%	94%	94%	94%	94%	94%	94%	94%

Fuel Cost ($000)

Resources	2021	2024	2025	2027	2031	2035	2040	2045
Newman 1	$ 431	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Newman 2	$ 273	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Newman 3	$ 2,299	$ 667	$ 55	$ 248	$ 46	$ -	$ -	$ -
Newman 4	$ 7,893	$ 2,755	$ 1,080	$ 1,435	$ 716	$ -	$ -	$ -
Newman 5	$ 31,126	$ 24,367	$ 17,006	$ 19,659	$ 22,951	$ 21,785	$ 24,625	$ 28,990
Newman 6	$ -	$ 5,465	$ 3,596	$ 4,364	$ 3,762	$ 1,579	$ 2,380	$ 4,155
Copper	$ 1,076	$ 70	$ -	$ -	$ -	$ -	$ -	$ -
Montana 1	$ 4,595	$ 4,852	$ 3,414	$ 3,784	$ 4,030	$ 2,455	$ 4,318	$ 5,534
Montana 2	$ 5,153	$ 5,102	$ 3,468	$ 4,056	$ 4,447	$ 3,079	$ 5,285	$ 5,678
Montana 3	$ 3,332	$ 3,087	$ 2,371	$ 2,768	$ 2,638	$ 1,279	$ 2,780	$ 4,139
Montana 4	$ 9,507	$ 7,298	$ 5,383	$ 5,946	$ 5,665	$ 4,884	$ 6,297	$ 6,488
Rio Grande 7	$ 93	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rio Grande 8	$ 1,340	$ 264	$ 49	$ 93	$ -	$ -	$ -	$ -
Rio Grande 9	$ 2,675	$ 987	$ 413	$ 603	$ 706	$ 42	$ 22	$ 429
Gas Peaker	$ -	$ -	$ -	$ -	$ -	$ 1,081	$ 2,239	$ 5,645
Palo Verde 1	$ 12,111	$ 12,185	$ 12,222	$ 12,259	$ 12,370	$ 12,500	$ 12,667	$ 12,834
Palo Verde 2	$ 12,169	$ 12,244	$ 12,281	$ 12,318	$ 12,430	$ 12,561	$ 12,728	$ 12,896
Palo Verde 3	$ 12,111	$ 12,185	$ 12,222	$ 12,259	$ 12,370	$ 12,500	$ 12,667	$ 12,834

Heat Rate (MMBtu/MWh)

Newman 1	12.28
Newman 2	11.51
Newman 3	10.97
Newman 4	10.12
Newman 5	7.741
Newman 6	10.101
Copper	19.916
Montana 1	9.373
Montana 2	9.334
Montana 3	9.933
Montana 4	9.339
Rio Grande 7	11.79
Rio Grande 8	11.902
Rio Grande 9	9.881
Gas Peaker	10.101
Palo Verde 1	10
Palo Verde 2	10
Palo Verde 3	10

Attachment C-2: Existing Units Operating Characteristics

Fixed O&M ($000)

Resources	2021	2024	2025	2027	2031	2035	2040	2045
Newman 1	$ 1,704	$ 5,737	$ 5,737	$ 5,737	$ -	$ -	$ -	$ -
Newman 2	$ 1,789	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Newman 3	$ 2,221	$ 2,221	$ 2,221	$ 5,231	$ 5,231	$ -	$ -	$ -
Newman 4	$ 5,014	$ 5,014	$ 5,014	$ 10,769	$ 10,769	$ -	$ -	$ -
Newman 5	$ 5,563	$ 5,563	$ 5,563	$ 5,563	$ 5,563	$ 5,563	$ 5,563	$ 5,563
Newman 6	$ -	$ 2,752	$ 2,752	$ 2,752	$ 2,752	$ 2,752	$ 2,752	$ 2,752
Copper	$ 1,167	$ 1,167	$ 1,167	$ 1,167	$ -	$ -	$ -	$ -
Montana 1	$ 1,613	$ 1,613	$ 1,613	$ 1,613	$ 1,613	$ 1,613	$ 1,613	$ 1,613
Montana 2	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623	$ 1,623
Montana 3	$ 1,484	$ 1,484	$ 1,484	$ 1,484	$ 1,484	$ 1,484	$ 1,484	$ 1,484
Montana 4	$ 1,076	$ 1,076	$ 1,076	$ 1,076	$ 1,076	$ 1,076	$ 1,076	$ 1,076
Rio Grande 7	$ 1,612	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rio Grande 8	$ 4,346	$ 4,346	$ 4,346	$ 4,346	$ 4,346	$ -	$ -	$ -
Rio Grande 9	$ 2,495	$ 2,495	$ 2,495	$ 2,495	$ 2,495	$ 2,495	$ 2,495	$ 2,495
Gas Peaker	$ -	$ -	$ -	$ -	$ -	$ 1,697	$ 3,312	$ 4,621
Palo Verde 1	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313
Palo Verde 2	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313
Palo Verde 3	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313	$ 28,313

Variable O&M ($000)

Resources	2021	2024	2025	2027	2031	2035	2040	2045
Newman 1	$ 466	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Newman 2	$ 415	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Newman 3	$ 2,388	$ 695	$ 57	$ 257	$ 48	$ -	$ -	$ -
Newman 4	$ 8,305	$ 2,887	$ 1,130	$ 1,497	$ 744	$ -	$ -	$ -
Newman 5	$ 33,855	$ 26,821	$ 18,189	$ 21,158	$ 24,347	$ 22,746	$ 25,862	$ 30,331
Newman 6	$ -	$ 5,964	$ 3,916	$ 4,688	$ 3,914	$ 1,639	$ 2,464	$ 4,299
Copper	$ 1,581	$ 282	$ -	$ -	$ -	$ -	$ -	$ -
Montana 1	$ 5,119	$ 5,348	$ 3,764	$ 4,110	$ 4,219	$ 2,540	$ 4,463	$ 5,714
Montana 2	$ 5,832	$ 5,707	$ 3,805	$ 4,427	$ 4,663	$ 3,195	$ 5,491	$ 5,881
Montana 3	$ 3,700	$ 3,494	$ 2,602	$ 3,032	$ 2,777	$ 1,335	$ 2,895	$ 4,307
Montana 4	$ 10,379	$ 8,028	$ 6,003	$ 6,579	$ 6,106	$ 5,134	$ 6,673	$ 6,808
Rio Grande 7	$ 161	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rio Grande 8	$ 1,700	$ 269	$ 50	$ 94	$ -	$ -	$ -	$ -
Rio Grande 9	$ 3,001	$ 1,138	$ 487	$ 689	$ 741	$ 44	$ 23	$ 447
Gas Peaker	$ -	$ -	$ -	$ -	$ -	$ 1,122	$ 2,319	$ 5,841
Palo Verde 1	$ 15,537	$ 15,612	$ 15,649	$ 15,686	$ 15,797	$ 15,927	$ 16,094	$ 16,261
Palo Verde 2	$ 15,613	$ 15,687	$ 15,724	$ 15,762	$ 15,873	$ 16,004	$ 16,172	$ 16,339
Palo Verde 3	$ 15,537	$ 15,612	$ 15,649	$ 15,686	$ 15,797	$ 15,927	$ 16,094	$ 16,261

Market Price

Year	Average Annual Price ($/MWh)
2021	$ 20.24
2022	$ 20.43
2023	$ 20.50
2024	$ 20.08
2025	$ 20.20
2026	$ 20.07
2027	$ 19.81
2028	$ 19.98
2029	$ 19.19
2030	$ 18.63
2031	$ 19.27
2032	$ 20.20
2033	$ 20.09
2034	$ 20.21
2035	$ 20.16
2036	$ 20.31
2037	$ 19.98
2038	$ 19.27
2039	$ 18.95
2040	$ 18.36
2041	$ 18.43
2042	$ 18.32
2043	$ 18.25
2044	$ 18.95
2045	$ 20.25

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Annual Energy (GWh) 2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,022	1,111	1,130	1,065	1,318	1,502
	Gas - Combustion Turbine	1,027	1,169	836	880	773	754	1,250	1,640
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	379	382	375	336	409	720
	Solar	289	952	1,467	1,551	2,200	3,058	3,443	4,239
	Battery Storage	-	12	(26)	(48)	(129)	(217)	(220)	(250)
	Imports	391	336	260	259	282	273	358	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	430	342	496	657	373	475
Least-Cost Case + ETA Resources	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	3	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	898	963	998	899	1,053	1,145
	Gas - Combustion Turbine	1,027	1,169	720	761	686	461	790	1,043
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	670	688	675	555	653	815
	Solar	289	953	1,464	1,530	2,211	3,351	4,068	5,345
	Battery Storage	-	12	(31)	(45)	(122)	(241)	(281)	(370)
	Imports	391	336	220	239	184	245	275	314
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	564	480	558	1,272	1,040	940
Separate System Planning	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	1	2	-	-	-	-
	Gas - Combined Cycle	1,766	1,388	1,031	1,122	1,141	969	1,192	1,385
	Gas - Combustion Turbine	1,040	1,177	754	831	807	477	795	1,105
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	305	306	295	182	165	412
	Solar	289	949	1,648	1,690	2,236	3,708	4,532	5,512
	Battery Storage	-	12	(54)	(60)	(138)	(295)	(350)	(405)
	Imports	391	327	259	247	291	229	225	282
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	134	450	407	444	1,288	2,358	2,353

Attachment D-1: E3 EPE Report Model Results June

		Annual Energy (GWh)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	1	2	-	-	-	-
	Gas - Combined Cycle	1,766	1,388	979	1,049	1,090	1,035	1,153	1,384
	Gas - Combustion Turbine	1,040	1,177	728	819	735	688	779	1,129
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	447	451	433	405	510	657
	Solar	289	949	1,594	1,633	2,242	3,101	4,087	5,075
	Battery Storage	-	12	(56)	(60)	(136)	(218)	(297)	(352)
	Imports	391	327	251	245	266	260	261	327
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	65	71
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	133	444	402	574	772	872	919
Low Load Growth	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	101	27	2	3	-	-	-	-
	Gas - Combined Cycle	1,596	1,244	978	1,065	1,127	1,025	1,258	1,472
	Gas - Combustion Turbine	983	1,065	799	875	806	644	1,109	1,492
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	333	336	335	291	350	562
	Solar	282	919	1,293	1,309	1,805	2,833	3,220	3,993
	Battery Storage	-	8	(29)	(29)	(96)	(209)	(215)	(245)
	Imports	381	325	269	262	289	268	342	437
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,492	8,862	8,958	9,194	9,759	10,459	11,813	13,623
	Excess Generation	22	163	337	318	410	642	359	427
High Load Growth	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	195	50	5	3	-	-	-	-
	Gas - Combined Cycle	1,909	1,522	1,067	1,151	1,118	1,107	1,388	1,500
	Gas - Combustion Turbine	1,088	1,256	865	914	776	867	1,411	1,747
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	431	436	413	396	463	976
	Solar	293	983	1,651	1,751	2,569	3,257	3,642	4,464
	Battery Storage	-	14	(47)	(68)	(159)	(222)	(222)	(256)
	Imports	400	343	272	271	280	284	372	441
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	9,050	9,447	9,558	9,830	10,488	11,297	12,803	14,783
	Excess Generation	10	100	394	290	554	655	385	540

Attachment D-1: E3 EPE Report Model Results June

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	134	31	7	3	-	-	-	-
	Gas - Combined Cycle	1,728	1,317	1,001	1,081	1,111	1,060	1,266	1,473
	Gas - Combustion Turbine	1,028	1,123	814	825	742	696	1,097	1,614
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	367	372	368	326	391	916
	Solar	285	866	1,263	1,278	1,665	2,340	2,627	2,711
	Battery Storage	-	11	(25)	(45)	(126)	(227)	(245)	(244)
	Imports	389	314	247	241	269	260	345	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	88	350	436	608	945	1,276	1,680	2,144
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	18	217	513	492	614	714	600	432
High DSM	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	133	30	2	3	0	-	-	-
	Gas - Combined Cycle	1,744	1,303	1,041	1,126	1,198	1,029	1,234	1,463
	Gas - Combustion Turbine	1,020	1,111	869	907	900	610	1,026	1,407
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	244	244	251	207	249	470
	Solar	288	934	1,332	1,337	1,621	2,752	3,114	3,719
	Battery Storage	-	10	(28)	(29)	(86)	(205)	(213)	(233)
	Imports	390	329	283	268	304	271	342	439
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,731	8,994	9,056	9,230	9,680	10,273	11,501	13,177
	Excess Generation	15	148	318	313	263	643	371	372
No New Gas	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	6	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	984	1,072	1,095	716	702	637
	Gas - Combustion Turbine	1,027	1,169	811	849	745	180	216	207
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	455	462	452	210	208	210
	Solar	289	952	1,467	1,545	2,197	4,287	5,691	7,680
	Battery Storage	-	12	(27)	(47)	(127)	(348)	(472)	(649)
	Imports	391	336	251	255	270	225	213	206
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	458	372	536	2,237	2,586	3,219

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Annual Energy (GWh) 2021	2024	2025	2027	2031	2035	2040	2045
No Lifetime Extensions	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	2	0	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	948	1,015	1,050	1,056	1,308	1,502
	Gas - Combustion Turbine	1,027	1,169	707	680	634	745	1,242	1,640
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	397	400	370	364	442	722
	Solar	289	953	1,693	1,897	2,475	3,050	3,432	4,237
	Battery Storage	-	12	(38)	(94)	(164)	(216)	(219)	(250)
	Imports	391	336	235	241	267	271	354	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	129	634	428	592	661	374	475
High Gas Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	125	31	3	3	-	-	-	-
	Gas - Combined Cycle	1,787	1,400	983	1,060	1,062	999	1,234	1,347
	Gas - Combustion Turbine	1,008	1,120	764	786	698	607	1,121	1,361
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	486	493	483	422	516	926
	Solar	290	956	1,465	1,542	2,190	3,165	3,570	4,490
	Battery Storage	-	9	(31)	(46)	(126)	(226)	(232)	(274)
	Imports	403	360	274	301	325	303	350	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	127	470	386	546	811	486	705
Low Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	127	23	3	3	-	-	-	-
	Gas - Combined Cycle	1,803	1,433	955	1,021	1,036	971	1,189	1,333
	Gas - Combustion Turbine	1,001	1,107	711	750	678	571	1,063	1,333
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	609	624	604	523	642	936
	Solar	289	958	1,476	1,548	2,179	3,178	3,576	4,573
	Battery Storage	-	11	(32)	(45)	(124)	(229)	(234)	(279)
	Imports	394	345	223	238	258	256	322	395
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	125	512	426	579	876	532	725

Attachment D-1: E3 EPE Report Model Results June

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Medium Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	120	22	3	3	-	-	-	-
	Gas - Combined Cycle	1,822	1,496	876	941	974	922	1,115	1,270
	Gas - Combustion Turbine	983	1,036	548	590	606	475	950	1,199
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	754	779	766	646	805	1,098
	Solar	290	961	1,600	1,663	2,221	3,268	3,695	4,746
	Battery Storage	-	7	(37)	(47)	(122)	(230)	(242)	(293)
	Imports	399	354	200	210	187	190	235	271
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	121	763	676	588	911	560	726
High Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	119	21	2	3	0	-	-	-
	Gas - Combined Cycle	1,835	1,540	658	724	862	872	979	832
	Gas - Combustion Turbine	962	989	428	458	488	393	630	544
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	869	904	927	776	940	832
	Solar	290	963	1,847	1,900	2,307	3,272	4,088	6,364
	Battery Storage	-	2	(40)	(46)	(115)	(230)	(271)	(474)
	Imports	408	362	181	195	162	187	193	192
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	120	1,270	1,182	882	1,065	1,041	1,596
80% Clean by 2035	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,022	1,111	1,127	1,050	1,159	1,295
	Gas - Combustion Turbine	1,027	1,169	836	880	766	696	1,057	1,256
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	379	382	375	331	683	1,029
	Solar	289	952	1,466	1,551	2,212	3,155	3,653	4,715
	Battery Storage	-	12	(26)	(48)	(129)	(224)	(234)	(290)
	Imports	391	336	261	260	278	264	240	286
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	431	343	514	770	469	738

Attachment D-1: E3 EPE Report Model Results June

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
20% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,022	1,111	1,130	1,065	1,318	1,342
	Gas - Combustion Turbine	1,027	1,169	836	880	773	751	1,249	1,353
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	379	382	375	336	409	927
	Solar	289	952	1,466	1,549	2,204	3,061	3,445	4,548
	Battery Storage	-	12	(26)	(48)	(129)	(217)	(220)	(277)
	Imports	391	336	261	262	277	274	357	397
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	431	345	491	655	371	705
40% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,022	1,111	1,127	1,051	1,133	1,135
	Gas - Combustion Turbine	1,027	1,169	836	880	766	696	980	985
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	379	382	375	331	763	1,034
	Solar	289	953	1,466	1,549	2,211	3,151	3,692	5,268
	Battery Storage	-	12	(26)	(48)	(128)	(224)	(241)	(350)
	Imports	391	336	261	262	279	265	232	219
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	129	432	345	515	768	533	965
60% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,022	1,111	1,127	1,052	864	852
	Gas - Combustion Turbine	1,027	1,169	836	880	766	698	561	560
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	379	382	375	331	927	838
	Solar	289	953	1,466	1,552	2,213	3,150	4,319	6,337
	Battery Storage	-	12	(26)	(48)	(128)	(224)	(276)	(470)
	Imports	391	336	261	259	278	263	164	174
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	432	342	513	769	1,338	1,586

Attachment D-1: E3 EPE Report Model Results June

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
80% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	3	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	910	976	1,017	907	577	550
	Gas - Combustion Turbine	1,027	1,169	734	777	696	468	168	183
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	638	654	638	532	1,260	1,231
	Solar	289	952	1,463	1,531	2,158	3,371	4,812	6,758
	Battery Storage	-	12	(30)	(45)	(123)	(239)	(338)	(517)
	Imports	391	336	227	241	245	232	80	88
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	546	461	605	1,183	2,430	2,751
90% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	3	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	910	978	1,018	808	340	313
	Gas - Combustion Turbine	1,027	1,169	736	776	696	320	41	58
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	637	655	639	463	1,965	1,995
	Solar	289	952	1,462	1,527	2,156	3,764	4,483	6,350
	Battery Storage	-	12	(30)	(45)	(123)	(278)	(311)	(472)
	Imports	391	336	226	244	245	193	40	47
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	547	465	603	1,440	3,210	3,645
100% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	6	3	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	984	1,072	1,095	716	-	-
	Gas - Combustion Turbine	1,027	1,169	811	849	745	180	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	455	462	452	210	969	1,406
	Solar	289	952	1,467	1,545	2,197	4,287	6,734	7,595
	Battery Storage	-	12	(27)	(47)	(127)	(348)	(1,163)	(1,402)
	Imports	391	336	251	255	270	225	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	620	1,455
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	458	372	536	2,237	10,954	12,232

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Annual Energy (GWh) 2021	2024	2025	2027	2031	2035	2040	2045
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	3	4	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	868	928	983	689	-	-
	Gas - Combustion Turbine	1,027	1,169	692	732	627	210	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	743	765	755	469	1,700	1,650
	Solar	289	952	1,460	1,525	2,217	4,074	4,752	6,753
	Battery Storage	-	12	(31)	(46)	(122)	(300)	(336)	(515)
	Imports	391	336	209	230	171	129	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	442	404
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	616	528	575	1,636	3,102	3,585

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	952	1,111	1,318
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	196
	Solar	115	385	629	629	904	1,241	1,298	1,580
	Battery Storage	-	50	183	256	582	1,032	1,116	1,284
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + ETA Resources	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	879	999	1,154
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	204	204	204	204	204	264
	Solar	115	385	629	629	887	1,482	1,684	2,050
	Battery Storage	-	50	183	236	552	1,084	1,252	1,698
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	835	835	989
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	87	87	87	87	87	159
	Solar	115	385	707	707	905	1,667	2,322	2,639
	Battery Storage	-	50	271	293	634	1,480	2,207	2,579
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	825	825	989
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	129	129	129	129	172	212
	Solar	115	385	672	672	936	1,290	1,645	1,990
	Battery Storage	-	50	269	291	601	1,038	1,420	1,741
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	121	195	206
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load Growth	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	847	989	1,182
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	96	96	96	96	96	153
	Solar	115	385	541	541	743	1,162	1,216	1,489
	Battery Storage	-	50	192	193	454	1,012	1,093	1,257
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Load Growth	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	1,062	1,237	1,451
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	123	123	123	123	123	266
	Solar	115	385	677	677	1,046	1,309	1,369	1,660
	Battery Storage	-	50	249	342	716	1,048	1,136	1,307
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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		Installed Capacity (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
High DG	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	942	1,078	1,322
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	106	106	106	106	106	249
	Solar	115	385	587	587	761	1,011	1,092	1,023
	Battery Storage	-	50	183	252	571	1,043	1,151	1,267
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	42	169	210	293	455	614	809	1,032
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	801	926	1,105
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	70	70	70	70	70	127
	Solar	115	385	558	558	641	1,146	1,189	1,384
	Battery Storage	-	50	187	191	425	1,000	1,070	1,209
	Imports	-	-	-	-	-	-	-	-
	Demand Response	49	66	71	82	100	101	103	103
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	668	668	668
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	132	132	132	132	132	132
	Solar	115	385	629	629	908	2,129	2,734	3,644
	Battery Storage	-	50	183	251	573	1,864	2,496	3,634
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
No Lifetime Extensions	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	234	234	144	144	-	-	-
	Gas - Combined Cycle	493	493	493	266	266	266	266	266
	Gas - Combustion Turbine	503	731	731	914	851	951	1,109	1,318
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	118	118	118	118	118	196
	Solar	115	385	769	769	1,018	1,235	1,292	1,579
	Battery Storage	-	50	230	434	743	1,031	1,115	1,284
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Gas Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	930	1,088	1,274
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	142	142	142	142	142	264
	Solar	115	385	629	629	905	1,312	1,369	1,712
	Battery Storage	-	50	183	249	570	1,047	1,131	1,312
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	920	1,078	1,267
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	181	181	181	181	181	267
	Solar	115	385	629	629	894	1,312	1,369	1,747
	Battery Storage	-	50	183	240	559	1,047	1,131	1,319
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Medium Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	909	1,060	1,248
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	236	236	236	236	236	300
	Solar	115	385	724	724	882	1,312	1,390	1,813
	Battery Storage	-	50	183	228	547	1,047	1,136	1,343
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	901	1,001	1,024
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	300	300	300	300	300	301
	Solar	115	385	927	927	972	1,312	1,640	2,583
	Battery Storage	-	50	183	211	521	1,047	1,189	2,082
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	938	1,075	1,253
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	194	285
	Solar	115	385	629	629	915	1,312	1,369	1,805
	Battery Storage	-	50	183	256	580	1,047	1,131	1,331
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
20% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	952	1,111	1,270
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	264
	Solar	115	385	629	629	904	1,242	1,299	1,733
	Battery Storage	-	50	183	256	582	1,032	1,116	1,316
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
40% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	939	1,064	1,178
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	221	300
	Solar	115	385	629	629	915	1,310	1,390	2,052
	Battery Storage	-	50	183	256	580	1,045	1,135	1,573
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	938	987	1,029
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	300	301
	Solar	115	385	629	629	915	1,311	1,822	2,573
	Battery Storage	-	50	183	256	580	1,046	1,194	2,062
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
80% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	885	885	885
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	192	192	192	192	507	507
	Solar	115	385	629	629	891	1,475	2,226	3,013
	Battery Storage	-	50	183	238	556	1,080	1,416	2,455
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
90% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	819	819	819
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	192	192	192	192	764	772
	Solar	115	385	628	628	891	1,681	2,284	3,081
	Battery Storage	-	50	183	238	556	1,276	1,601	2,627
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	668	668	668
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	132	132	132	132	1,228	1,605
	Solar	115	385	629	629	908	2,129	4,851	5,217
	Battery Storage	-	50	183	251	573	1,864	6,191	7,470
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	298	701
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Installed Capacity (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	-	-
	Gas - Combustion Turbine	503	731	731	731	668	774	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	231	231	231	231	687	687
	Solar	115	385	628	628	883	1,801	2,353	3,200
	Battery Storage	-	50	183	233	548	1,403	1,804	2,864
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	1,040	1,040
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Additions (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	512	671	878
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	196
	Solar	-	270	514	514	789	1,196	1,280	1,842
	Battery Storage	-	50	183	256	582	1,032	1,116	1,334
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + ETA Resources	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	439	559	714
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	204	204	204	204	204	264
	Solar	-	270	514	514	772	1,437	1,666	2,312
	Battery Storage	-	50	183	236	552	1,084	1,252	1,748
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	395	395	549
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	87	87	87	87	87	159
	Solar	-	270	592	592	790	1,622	2,304	2,901
	Battery Storage	-	50	271	293	634	1,480	2,207	2,629
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Additions (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	385	385	549
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	129	129	129	129	172	212
	Solar	-	270	557	557	821	1,245	1,627	2,252
	Battery Storage	-	50	269	291	601	1,038	1,420	1,791
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	121	195	206
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load Growth	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	407	549	742
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	96	96	96	96	96	153
	Solar	-	270	426	426	628	1,117	1,198	1,751
	Battery Storage	-	50	192	193	454	1,012	1,093	1,307
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Load Growth	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	622	797	1,011
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	123	123	123	123	123	266
	Solar	-	270	562	562	931	1,264	1,351	1,922
	Battery Storage	-	50	249	342	716	1,048	1,136	1,357
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Additions (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	502	638	882
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	106	106	106	106	106	249
	Solar	-	270	472	472	646	966	1,074	1,285
	Battery Storage	-	50	183	252	571	1,043	1,151	1,317
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	42	169	210	293	455	614	809	1,032
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	361	486	665
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	70	70	70	70	70	127
	Solar	-	270	443	443	526	1,101	1,171	1,646
	Battery Storage	-	50	187	191	425	1,000	1,070	1,259
	Imports	-	-	-	-	-	-	-	-
	Demand Response	49	66	71	82	100	101	103	103
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	228	228	228
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	132	132	132	132	132	132
	Solar	-	270	514	514	793	2,084	2,716	3,906
	Battery Storage	-	50	183	251	573	1,864	2,496	3,684
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Additions (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
No Lifetime Extensions	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	411	411	511	669	878
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	118	118	118	118	118	196
	Solar	-	270	654	654	903	1,190	1,274	1,841
	Battery Storage	-	50	230	434	743	1,031	1,115	1,334
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Gas Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	490	648	834
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	142	142	142	142	142	264
	Solar	-	270	514	514	790	1,267	1,351	1,974
	Battery Storage	-	50	183	249	570	1,047	1,131	1,362
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	480	638	827
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	181	181	181	181	181	267
	Solar	-	270	514	514	779	1,267	1,351	2,009
	Battery Storage	-	50	183	240	559	1,047	1,131	1,369
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Additions (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
Medium Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	469	620	808
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	236	236	236	236	236	300
	Solar	-	270	609	609	767	1,267	1,372	2,075
	Battery Storage	-	50	183	228	547	1,047	1,136	1,393
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	461	561	584
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	300	300	300	300	300	301
	Solar	-	270	812	812	857	1,267	1,622	2,845
	Battery Storage	-	50	183	211	521	1,047	1,189	2,132
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	498	635	813
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	194	285
	Solar	-	270	514	514	800	1,267	1,351	2,067
	Battery Storage	-	50	183	256	580	1,047	1,131	1,381
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Additions (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
20% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	512	671	830
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	264
	Solar	-	270	514	514	789	1,197	1,281	1,995
	Battery Storage	-	50	183	256	582	1,032	1,116	1,366
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
40% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	499	624	738
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	221	300
	Solar	-	270	514	514	800	1,265	1,372	2,314
	Battery Storage	-	50	183	256	580	1,045	1,135	1,623
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	498	547	589
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	300	301
	Solar	-	270	514	514	800	1,266	1,804	2,835
	Battery Storage	-	50	183	256	580	1,046	1,194	2,112
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Additions (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
80% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	445	445	445
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	192	192	192	192	507	507
	Solar	-	270	514	514	776	1,430	2,208	3,275
	Battery Storage	-	50	183	238	556	1,080	1,416	2,505
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
90% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	379	379	379
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	192	192	192	192	764	772
	Solar	-	270	513	513	776	1,636	2,266	3,343
	Battery Storage	-	50	183	238	556	1,276	1,601	2,677
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	228	228	228
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	132	132	132	132	1,228	1,605
	Solar	-	270	514	514	793	2,084	4,833	5,479
	Battery Storage	-	50	183	251	573	1,864	6,191	7,470
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	298	701
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Additions (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	334	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	231	231	231	231	687	687
	Solar	-	270	513	513	768	1,756	2,335	3,462
	Battery Storage	-	50	183	233	548	1,403	1,804	2,914
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	334	334
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Retirements (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Least-Cost (Reference Case)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + ETA Resources	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Retirements (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load Growth	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Load Growth	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Retirements (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Retirements (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
No Lifetime Extensions	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(192)	(192)	(282)	(282)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	(227)	(227)	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Gas Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Retirements (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
Medium Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Retirements (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
20% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
40% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
80% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
90% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Resource Type	Cumulative Capacity Retirements (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-1: E3 EPE Report Model Results June

Scenario	Annual Revenue Requirement ($M) 2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	$ 246	$ 233	$ 246	$ 265	$ 290	$ 351	$ 409	$ 512
Least-Cost Case + ETA Resources	$ 246	$ 233	$ 249	$ 266	$ 291	$ 356	$ 412	$ 519
Separate System Planning	$ 247	$ 234	$ 252	$ 269	$ 295	$ 376	$ 471	$ 577
Separate System Planning (w/ H2)	$ 247	$ 234	$ 252	$ 269	$ 294	$ 355	$ 438	$ 543
Low Load Growth	$ 239	$ 227	$ 239	$ 255	$ 275	$ 327	$ 380	$ 478
High Load Growth	$ 253	$ 239	$ 256	$ 277	$ 307	$ 377	$ 439	$ 546
High DG	$ 245	$ 231	$ 243	$ 261	$ 283	$ 336	$ 388	$ 482
High DSM	$ 245	$ 230	$ 241	$ 256	$ 272	$ 317	$ 364	$ 454
No New Gas	$ 246	$ 233	$ 247	$ 265	$ 290	$ 394	$ 470	$ 601
No Lifetime Extensions	$ 246	$ 228	$ 246	$ 276	$ 307	$ 354	$ 412	$ 515
High Gas Price	$ 257	$ 242	$ 252	$ 272	$ 297	$ 358	$ 418	$ 522
Low Carbon Price	$ 291	$ 277	$ 285	$ 304	$ 329	$ 390	$ 450	$ 556
Medium Carbon Price	$ 358	$ 341	$ 342	$ 361	$ 386	$ 447	$ 512	$ 623
High Carbon Price	$ 469	$ 449	$ 433	$ 452	$ 478	$ 539	$ 609	$ 730
80% Clean by 2035	$ 246	$ 233	$ 246	$ 265	$ 290	$ 352	$ 409	$ 512
20% CO2 Red. by 2040	$ 246	$ 233	$ 246	$ 265	$ 290	$ 351	$ 409	$ 511
40% CO2 Red. by 2040	$ 246	$ 233	$ 246	$ 265	$ 290	$ 352	$ 409	$ 519
60% CO2 Red. by 2040	$ 246	$ 233	$ 246	$ 265	$ 290	$ 352	$ 421	$ 537
80% CO2 Red. by 2040	$ 246	$ 233	$ 248	$ 266	$ 290	$ 356	$ 464	$ 580
90% CO2 Red. by 2040	$ 246	$ 233	$ 248	$ 266	$ 290	$ 366	$ 503	$ 620
100% CO2 Red. by 2040	$ 246	$ 233	$ 247	$ 265	$ 290	$ 394	$ 1,102	$ 1,269
100% CO2 Red. by 2040 (w/ H2)	$ 246	$ 233	$ 250	$ 267	$ 291	$ 375	$ 561	$ 675

Attachment D-1: E3 EPE Report Model Results June

		Clean Energy (% of Load)							
Scenario	Clean Energy Type	2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Renewable %	4%	12%	22%	23%	28%	35%	36%	40%
	Zero Carbon %	62%	68%	77%	76%	79%	81%	77%	75%
Least-Cost Case + ETA Resources	Renewable %	4%	12%	25%	26%	32%	39%	42%	48%
	Zero Carbon %	62%	68%	80%	79%	82%	86%	83%	83%
Separate System Planning	Renewable %	4%	12%	23%	23%	28%	39%	42%	46%
	Zero Carbon %	62%	68%	78%	77%	78%	85%	83%	81%
Separate System Planning (w/ H2)	Renewable %	4%	12%	24%	24%	29%	36%	41%	45%
	Zero Carbon %	62%	68%	79%	78%	80%	82%	83%	80%
Low Load Growth	Renewable %	4%	12%	20%	20%	25%	34%	35%	38%
	Zero Carbon %	64%	70%	77%	76%	77%	82%	77%	75%
High Load Growth	Renewable %	4%	12%	23%	24%	31%	36%	36%	41%
	Zero Carbon %	61%	66%	77%	76%	80%	80%	76%	75%
High DG	Renewable %	4%	13%	22%	24%	29%	35%	37%	40%
	Zero Carbon %	63%	70%	78%	77%	79%	82%	78%	76%
High DSM	Renewable %	4%	12%	19%	20%	23%	33%	34%	37%
	Zero Carbon %	63%	69%	76%	75%	75%	82%	78%	75%
No New Gas	Renewable %	4%	12%	22%	23%	29%	44%	51%	58%
	Zero Carbon %	62%	68%	78%	77%	79%	90%	91%	93%
No Lifetime Extensions	Renewable %	4%	12%	24%	26%	31%	35%	36%	40%
	Zero Carbon %	62%	68%	80%	80%	81%	81%	77%	75%
High Gas Price	Renewable %	4%	12%	23%	24%	29%	36%	37%	43%
	Zero Carbon %	62%	68%	78%	78%	80%	83%	78%	78%
Low Carbon Price	Renewable %	4%	12%	24%	25%	31%	37%	38%	43%
	Zero Carbon %	62%	68%	80%	79%	81%	84%	79%	79%
Medium Carbon Price	Renewable %	4%	12%	27%	28%	33%	39%	41%	46%
	Zero Carbon %	62%	68%	83%	82%	83%	86%	82%	81%
High Carbon Price	Renewable %	4%	12%	31%	32%	35%	41%	45%	54%
	Zero Carbon %	62%	68%	86%	86%	85%	87%	86%	89%
80% Clean by 2035	Renewable %	4%	12%	22%	23%	29%	36%	39%	45%
	Zero Carbon %	62%	68%	77%	76%	79%	82%	80%	80%
20% CO2 Red. by 2040	Renewable %	4%	12%	22%	23%	29%	35%	36%	43%
	Zero Carbon %	62%	68%	77%	76%	79%	81%	77%	79%
40% CO2 Red. by 2040	Renewable %	4%	12%	22%	23%	29%	36%	40%	49%
	Zero Carbon %	62%	68%	77%	76%	79%	82%	81%	84%
60% CO2 Red. by 2040	Renewable %	4%	12%	22%	23%	29%	35%	46%	54%
	Zero Carbon %	62%	68%	77%	76%	79%	82%	87%	89%
80% CO2 Red. by 2040	Renewable %	4%	12%	24%	25%	31%	39%	53%	59%
	Zero Carbon %	62%	68%	80%	79%	81%	86%	93%	94%
90% CO2 Red. by 2040	Renewable %	4%	12%	24%	25%	31%	42%	56%	62%
	Zero Carbon %	62%	68%	80%	79%	81%	88%	97%	97%
100% CO2 Red. by 2040	Renewable %	4%	12%	22%	23%	29%	44%	62%	67%
	Zero Carbon %	62%	68%	78%	77%	79%	90%	100%	100%
100% CO2 Red. by 2040 (w/ H2)	Renewable %	4%	12%	25%	26%	32%	45%	56%	62%
	Zero Carbon %	62%	68%	81%	80%	83%	91%	100%	100%

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El Paso Electric IRP Modeling Update

Portfolio Analysis Results

6/1/2021

Arne Olson, Senior Partner
Jack Moore, Director
Joe Hooker, Senior Managing Consultant
Huai Jiang, Senior Consultant
Manu Mogadali, Senior Consultant
Chen Zhang, Consultant

Agenda

+ Assumption updates
+ Updated Reference Case results
+ High DSM sensitivity results
+ New Mexico REA Requirements
+ New Mexico REA Scenario Results

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Assumption Updates

Unit Lifetime Extensions

- E3 modeled unit lifetime extensions for the following units that are currently scheduled to retire prior to 2030

Resource	Planned Retirement Year	Extension Period	Capital + Fixed O&M (2021 $/kW-yr)
Rio Grande 7	2022	5 years	$113.73
Newman 1	2022	5 years	$78.59
Newman 2	2022	5 years	$79.98
Newman 3	2026	5 years	$58.12
Newman 4	2026	5 years	$47.44

- In the modeling, unit extensions for Rio Grande 7 and Newman 2 are not selected, but the other unit extensions are

Planning Reserve Margin

- **The modeling assumes a 2-day-in-10-year reliability standard for 2025 as a transition to the more common 1-day-in-10-year reliability standard starting in 2030**

Metric	2025	2030+
Reliability Target	Two days with outages every ten years on average (0.2 LOLE)	One day with outages every ten years on average (0.1 LOLE)
Target PCAP PRM	10.1%	12.9%

LOLE = Loss-of-Load Expectation; PCAP = Perfect Capacity

- **Under this PRM, all generators count toward the PRM based on their effective load carrying capability (ELCC)**

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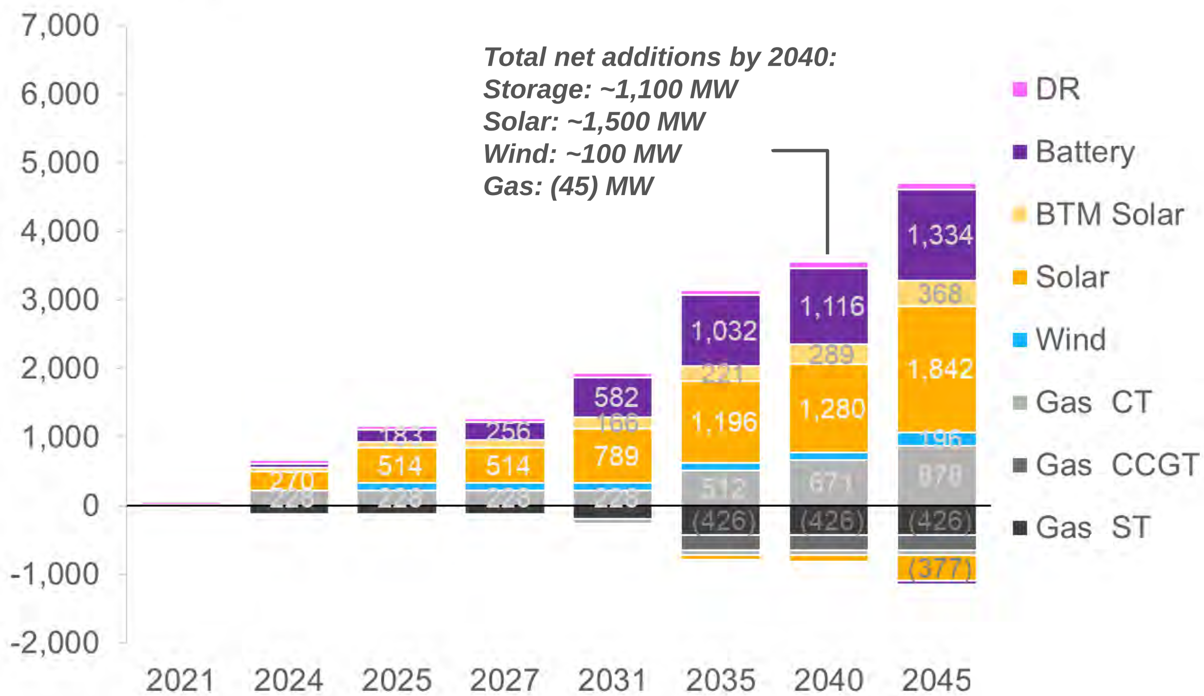
Updated Reference Case Results

Scenarios and Sensitivities

Run	Note	Presented Previously	Presented Today
Least-Cost (Reference Case)	Least-cost optimization used as reference case for all sensitivities	✓	✓
Least-Cost Case + REA Resources	Additional resources added to Least-Cost Case for New Mexico REA		✓
Separate System Planning	New Mexico system planned separately for purposes of satisfying REA		✓
Low Load Growth	3-4% higher native system load forecast		
High Load Growth	3-4% lower native system load forecast		
High DG	High DG forecast		
High DSM	More smart thermostats, doubling of energy efficiency		✓
No New Gas	No new gas after Newman 6		
No Lifetime Extensions	All plants retire as scheduled		
High Gas Price	Gas prices 15% higher		
Low Carbon Price	$8 per metric ton of CO_2 in 2010, rising at 2.5% per year		
Medium Carbon Price	$20 per metric ton of CO_2 in 2010, rising at 2.5% per year		
High Carbon Price	$40 per metric ton of CO_2 in 2010, rising at 2.5% per year		
80% Clean by 2035	80% zero-carbon energy	✓	
20% CO_2 Red. by 2040	20% reduction in CO_2 emissions	✓	
40% CO_2 Red. by 2040	40% reduction in CO_2 emissions	✓	
60% CO_2 Red. by 2040	60% reduction in CO_2 emissions	✓	
80% CO_2 Red. by 2040	80% reduction in CO_2 emissions	✓	
90% CO_2 Red. by 2040	90% reduction in CO_2 emissions	✓	
100% CO_2 Red. by 2040	100% reduction in CO_2 emissions	✓	
100% CO_2 Red. by 2040 (w/ H2)	100% reduction in CO_2 emissions with hydrogen	✓	

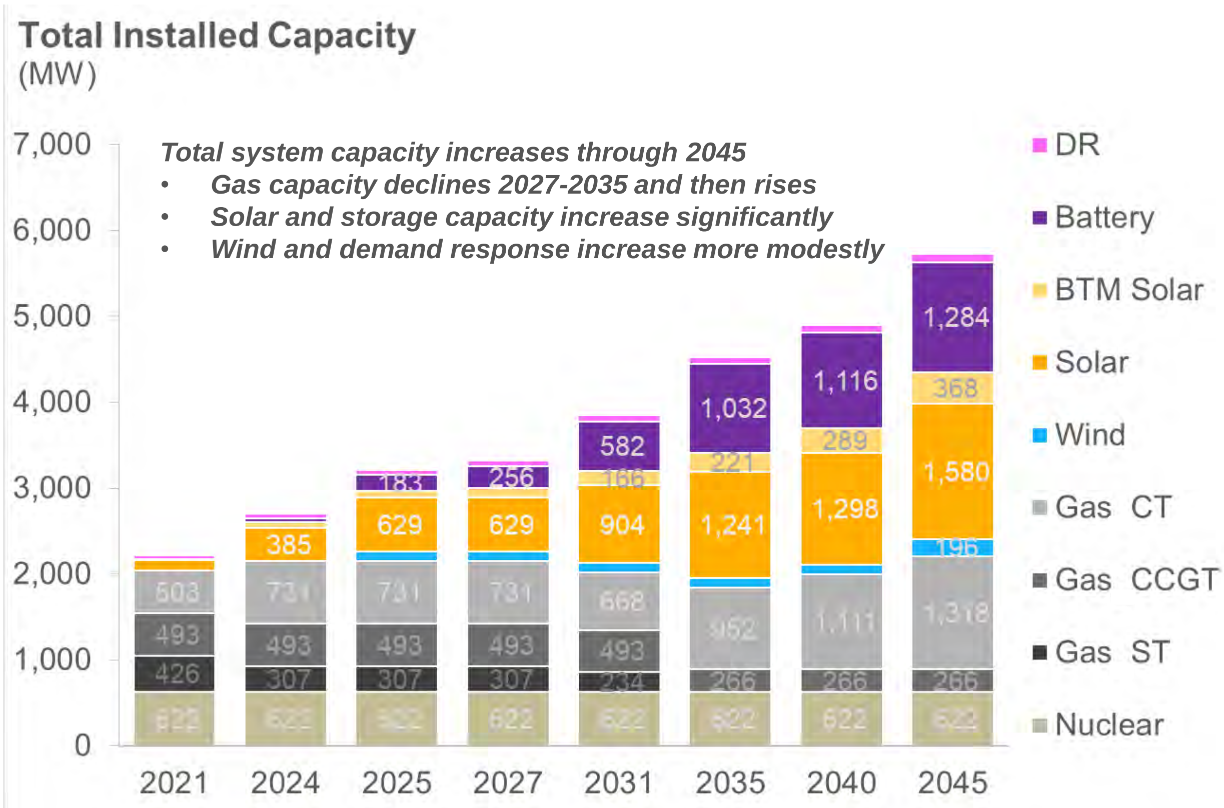
Reference Case: Additions and Retirements

Cumulative New & Retired Capacity
(Installed MW)



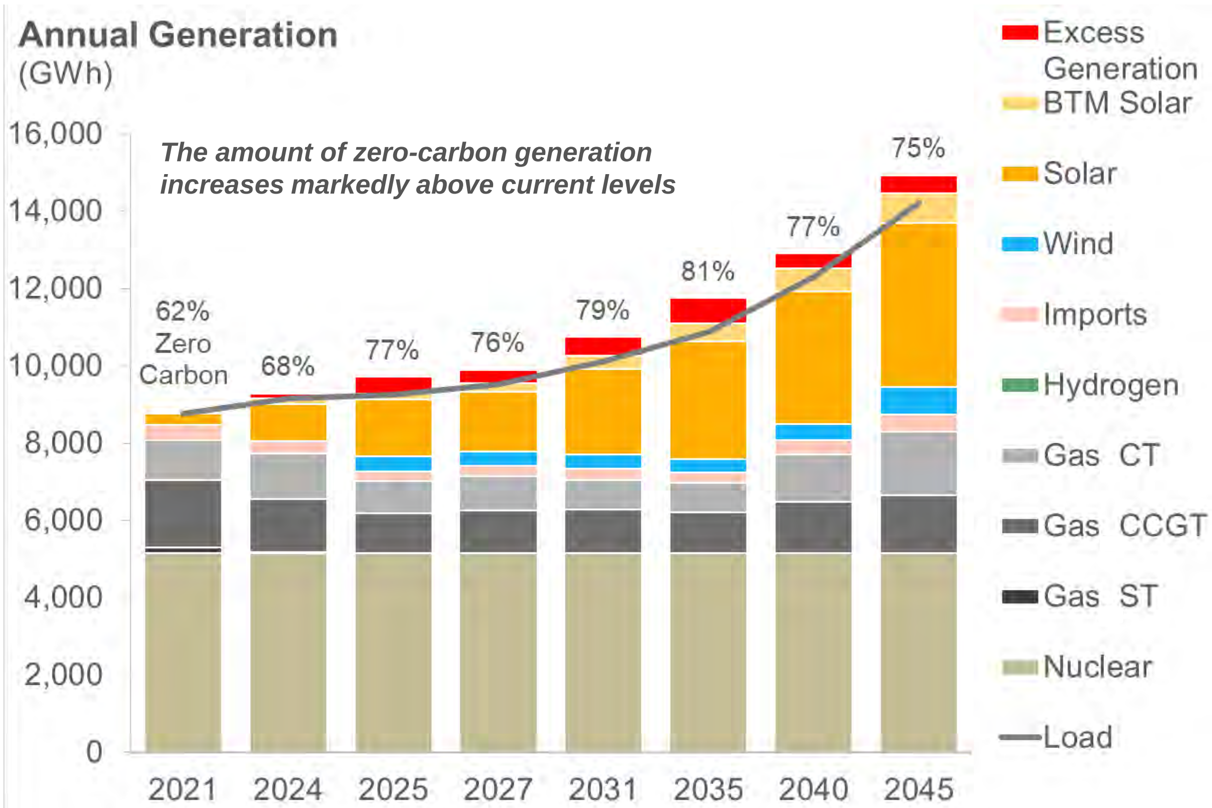
DR = demand response; BTM Solar = behind-the-meter solar

Reference Case: Total Capacity



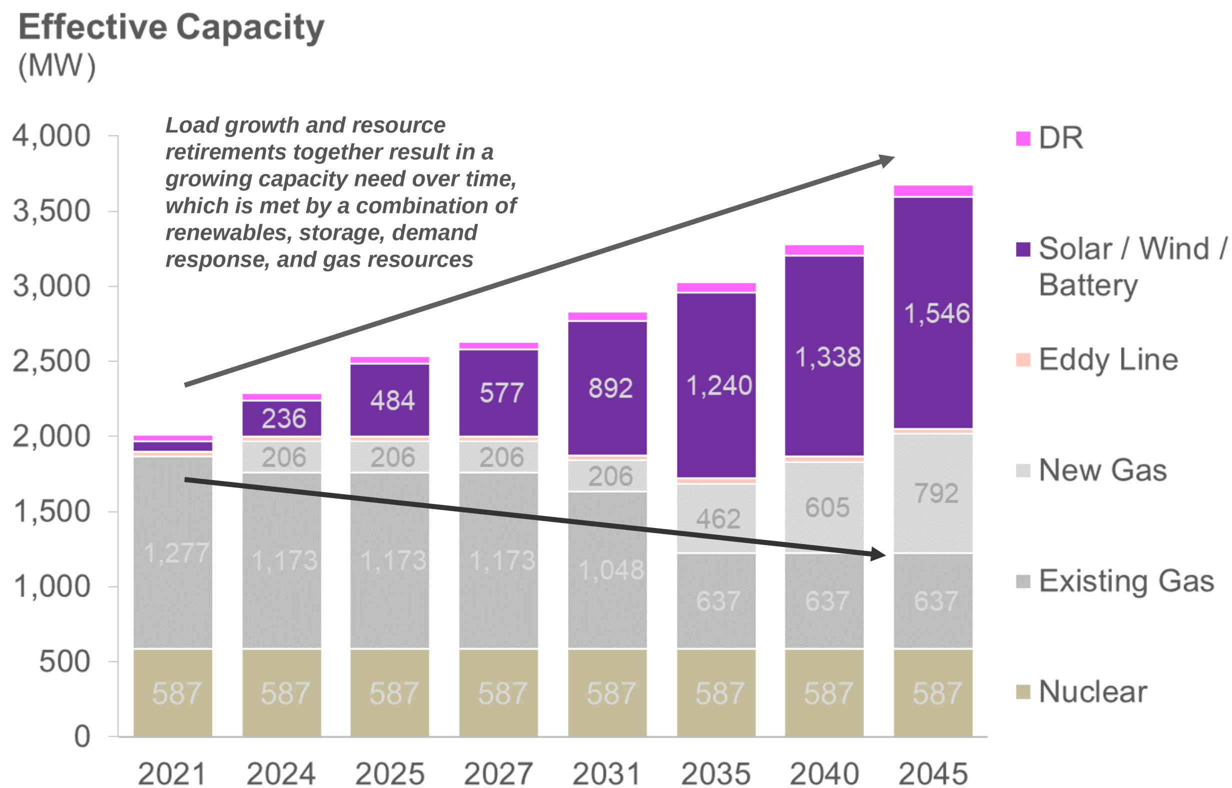
DR = demand response; BTM Solar = behind-the-meter solar

Reference Case: Annual Generation



BTM Solar = behind-the-meter solar

Reference Case: Effective Capacity



Effective capacity is the amount of capacity that can be counted towards the PRM

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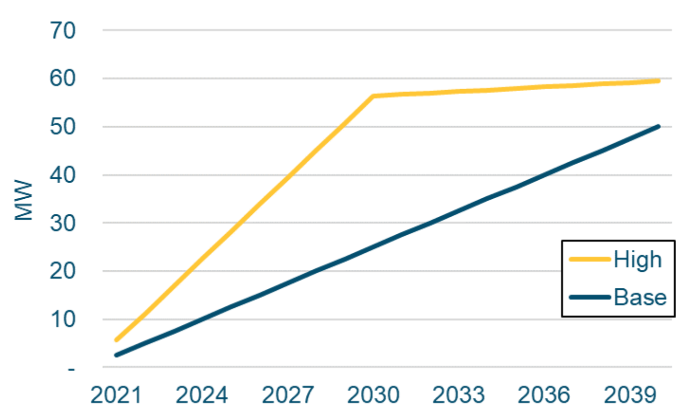
High DSM Sensitivity Results

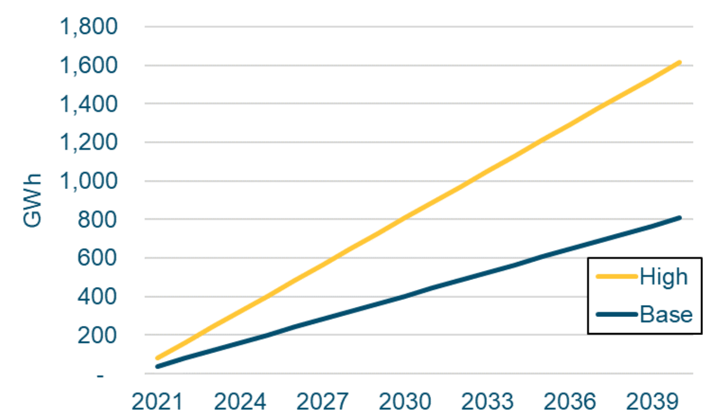
High DSM Sensitivity Assumptions

Smart Thermostats



- Base: 50MW by 2040
- High: 60MW by 2040

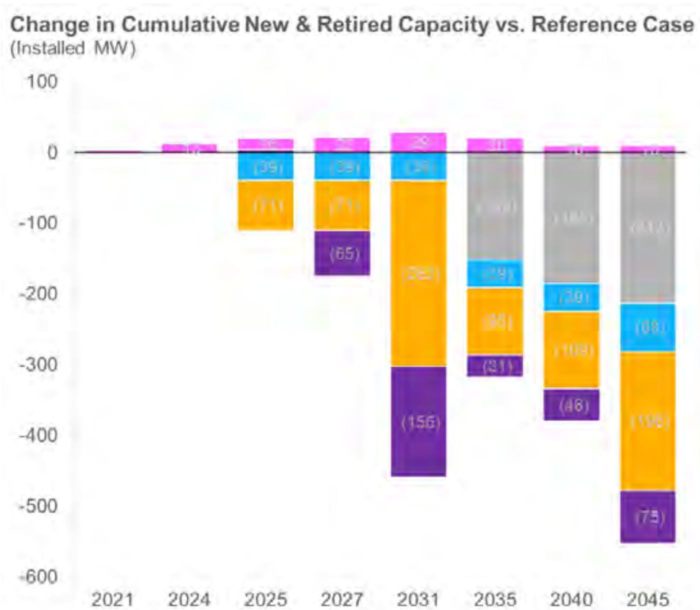
Energy Efficiency



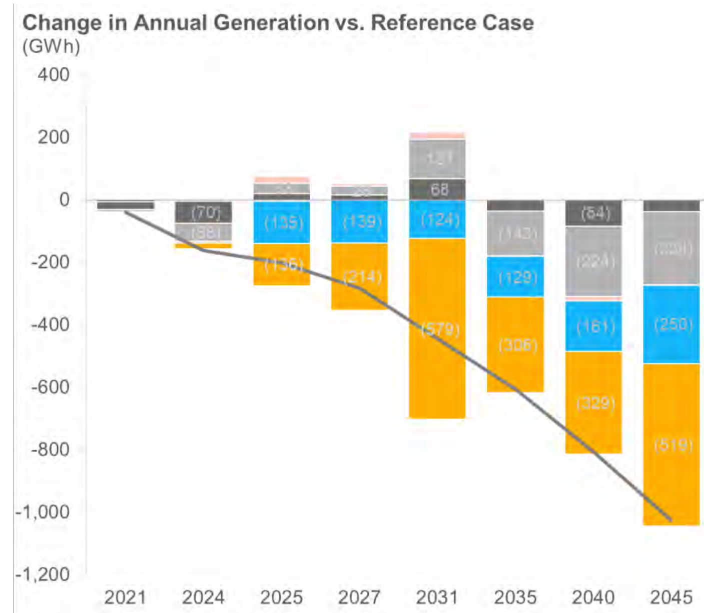
- Base: 6.5% of native system load in 2040
- High: 13% of native system load in 2040
- An incremental ~800 GWh in 2040 Corresponds to ~90 MW of savings on average throughout the year

High DSM Scenario Results

Change in Capacity



Generation Mix



Nuclear Gas ST Gas CCGT Gas CT Imports Wind Solar BTM Solar Battery DR Excess Generation Load

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New Mexico REA Requirements

New Mexico Renewable Energy Act

+ **There are key requirements in the statutory language setting renewable energy and zero carbon requirements in New Mexico (emphasis added):**

  "A public utility shall meet the renewable portfolio standard requirements, as provided in this section, to include renewable energy in its electric energy supply portfolio *as demonstrated by its retirement of renewable energy certificates*; *provided that the associated* ***renewable energy is delivered*** *to the public utility and assigned to the public utility's New Mexico customers…*

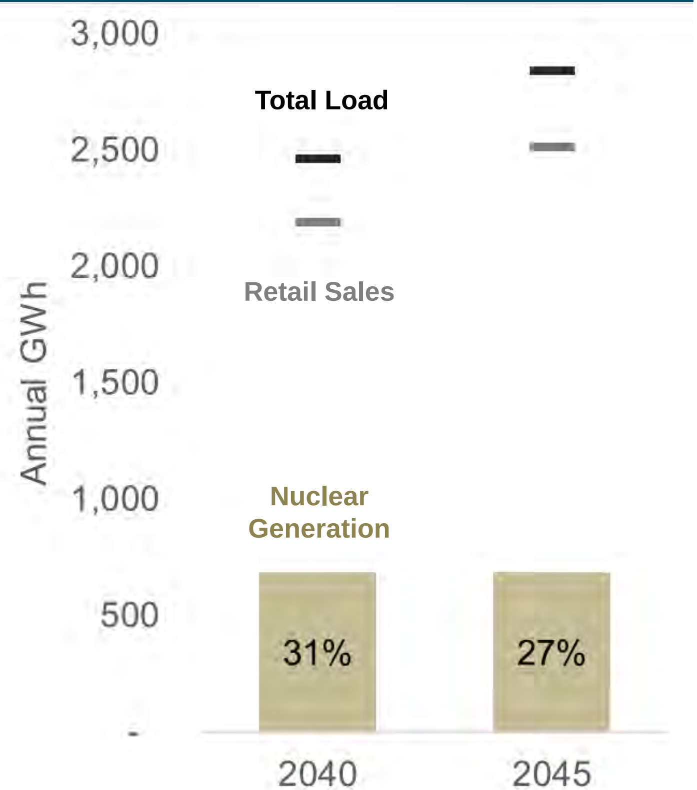
  (5) no later than January 1, 2040, renewable energy resources shall supply no less than eighty percent of all retail sales of electricity in New Mexico; *provided that compliance with this standard until December 31, 2047 shall not require the public utility to displace zero carbon resources* in the utility's generation portfolio on the effective date of this 2019 act; and

  (6) no later than January 1, 2045, *zero carbon resources shall supply one hundred percent of* ***all retail sales of electricity in New Mexico***. Reasonable and consistent progress shall be made over time toward this requirement."

+ **The scenarios analyzed consider multiple approaches for REA implementation**
  - Share of NM load served with renewable energy, given that El Paso Electric serves NM load with greater than 20% non-renewable zero-carbon resources (i.e. Palo Verde)
  - Annual vs. hourly balancing periods for 100% zero-carbon generation
  - Whether combustion resources may be utilized to ensure reliability for NM customers

New Mexico REA Requirements in 2040+

New Mexico Nuclear Generation & Load

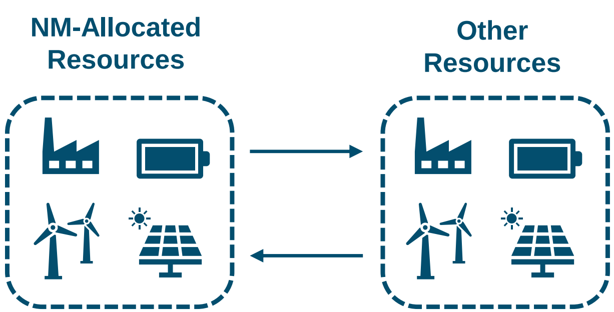


- The REA requires 80% RPS by 2040, unless doing so would require displacing existing zero-carbon generation
- New Mexico's share of Palo Verde 1 and 2 supplies 31% of New Mexico's retail sales in 2040 and 27% in 2045
- For purposes of IRP modeling, El Paso Electric has directed E3 to require New Mexico zero-carbon generation (renewables + nuclear) to equal or exceed 100% of New Mexico retail sales or load starting in 2040

Two Approaches for Modeling Zero-Carbon Generation Balancing

Annual Balancing

- New Mexico-allocated zero-carbon resources must generate enough energy on an annual basis to match the REA NM retail sales target
- Natural gas resources and/or imports can serve New Mexico's energy needs in some hours if that generation is offset by additional zero-carbon generation in other hours
- Annual balancing allows New Mexico customers to reap the benefits of being served by a larger system



NM customers can be served by gas resources and unspecified imports if offset in other hours

Hourly Balancing

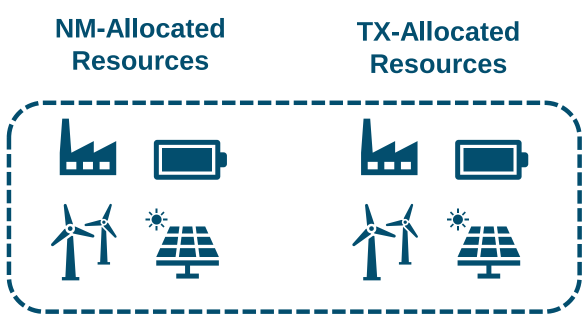
- New Mexico cannot receive power from gas resources or unspecified imports in any hour
- Zero-carbon generation from New Mexico-allocated resources must serve New Mexico energy demand in all hours of the year
- This would be a more stringent zero-carbon requirement, as it would not allow for balancing between New Mexico and Texas resources

NM customers cannot be served by gas resources or unspecified imports an any hour

Two Approaches for Modeling Capacity Pooling to Ensure Reliability

Capacity Pooling Allowed

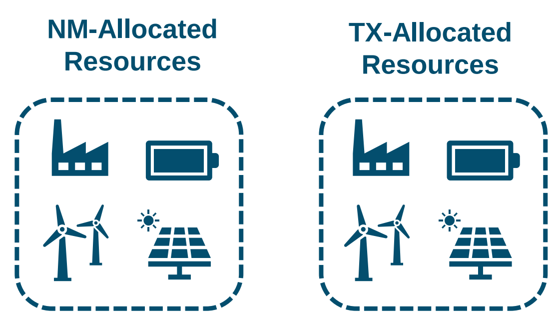
- For reliability planning purposes, NM and TX loads can be served by NM resources, TX resources, and/or system resources
  - If the NM jurisdiction doesn't have enough resources to satisfy load in an hour, then it can rely on TX resources, and vice versa
- NM and TX customers must still pay for enough resources to satisfy their share of system reliability needs



All resources together ensure systemwide reliability across all hours, subject to the reliability standard

Capacity Pooling NOT Allowed

- For planning purposes, TX and NM must each have enough resources to ensure reliability across a range of potential conditions without relying on the other jurisdiction (i.e. on a standalone basis)
- This would be a more stringent planning approach; NM would need to plan to have enough resources without falling back on TX gas resources in some hours



For planning purposes, each jurisdiction ensures reliability on its own across all hours, subject to the reliability standard

New Mexico REA Scenarios and Jurisdictional Allocation

- **E3 modeled a few scenarios with different approaches for how to satisfy the REA requirements**
  - Different approaches of the REA requirements have meaningful implications on how planning is performed for New Mexico customers
  - The more stringent approaches of the REA requirements will result in higher system costs relative to less stringent approaches
  - To ensure equitable treatment of customers across jurisdictions, any incremental costs of satisfying the REA requirements would be allocated to New Mexico customers
- **For each scenario, resources and costs are allocated between the New Mexico and Texas jurisdictions**
  - The allocation of resources follows directly from a particular approach to modeling REA compliance. If a particular approach requires more resources to be added versus the least-cost case, then those resources are allocated to the New Mexico jurisdiction
  - Capacity, generation, and cost for the New Mexico jurisdiction are presented for each scenario

New Mexico REA Scenarios

	Least Cost ("LC")	**Least Cost + REA Resources** ("LC+REA")	**Separate System Planning** ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

More stringent REA interpretation →

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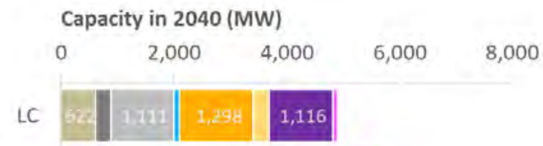
New Mexico REA Scenario Results

New Mexico REA Scenarios

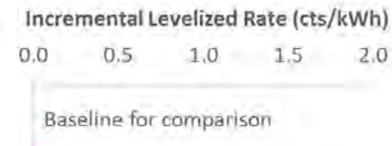
	Least Cost ("LC")
Portfolio optimization	Least-cost system optimization
NM zero-carbon generation balancing period	Annual
NM and TX capacity pooling to ensure reliability	✓
Resource allocation	Resources allocated proportionally; more RECs allocated to NM
NM allocated new gas capacity	✓

Resource Portfolios and Costs by Scenario
Least Cost Scenario

Total System



New Mexico



112 MW of new gas capacity is allocated to New Mexico customers by 2040

This analysis does not assume Palo Verde 3 generation is allocated to New Mexico, resulting in a lower zero-carbon generation share than the rest of the system

This scenario allocates a share of new gas capacity to NM customers. This capacity could be converted to run on a higher share of hydrogen fuel in the future. More RECs would be allocated to NM customers to satisfy the REA.

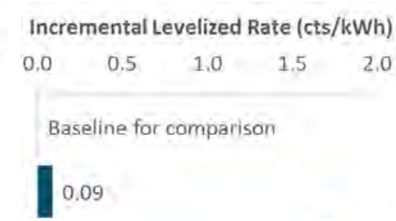
Nuclear ▪ Gas ST ▪ Gas CCGT ▪ Gas CT ▪ Hydrogen ▪ Net Purchases (Sales) ▪ Wind ▪ Solar ▪ BTM Solar ▪ Geothermal ▪ Battery ▪ DR

New Mexico REA Scenarios

	Least Cost ("LC")	**Least Cost + REA Resources** ("LC+REA")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements
NM zero-carbon generation balancing period	Annual	Annual
NM and TX capacity pooling to ensure reliability	✓	✓
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico
NM allocated new gas capacity	✓	✗

Resource Portfolios and Costs by Scenario
Least Cost + REA Scenario

Total System | **New Mexico**



Gas generation serves a portion of New Mexico customers' energy needs in some hours, but that is more than offset by

This scenario adds more solar and storage capacity for NM customers to satisfy the RPS/REA targets, while not allocating any new gas to NM customers. This results in a modest cost increase vs. Least Cost scenario.

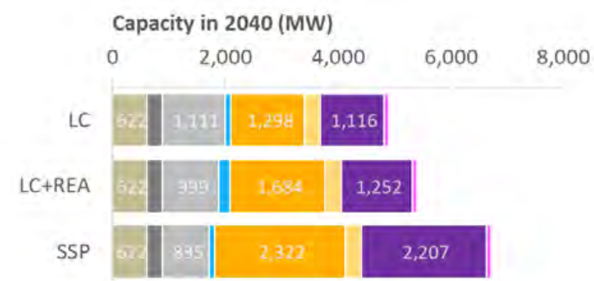
Nuclear ■ Gas ST ■ Gas CCGT ■ Gas CT ■ Hydrogen ■ Net Purchases (Sales) ■ Wind ■ Solar ■ BTM Solar ■ Geothermal ■ Battery ■ DR

New Mexico REA Scenarios

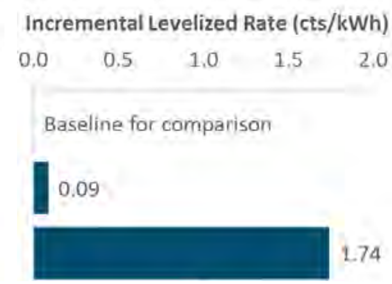
	Least Cost ("LC")	Least Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio optimization	Least-cost system optimization	Reoptimize Least Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM zero-carbon generation balancing period	Annual	Annual	Hourly
NM and TX capacity pooling to ensure reliability	✓	✓	✗
Resource allocation	Resources allocated proportionally; more RECs allocated to NM	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM allocated new gas capacity	✓	✗	✗

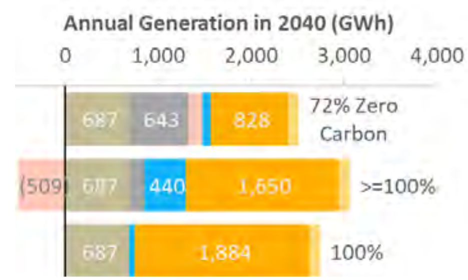
Resource Portfolios and Costs by Scenario
Separate System Planning Scenario

Total System



New Mexico



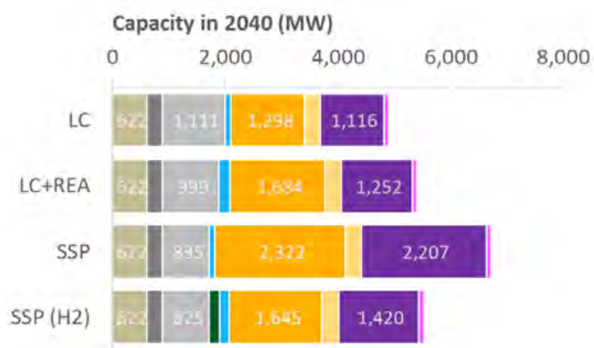


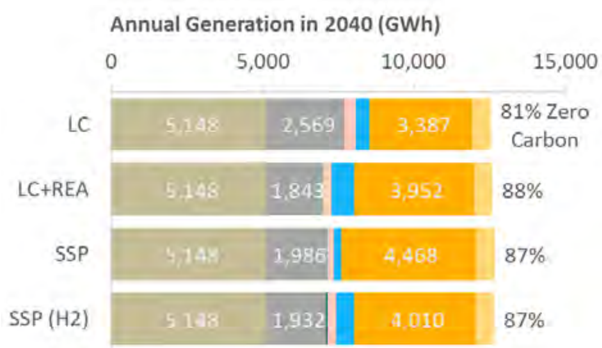
This scenario requires significantly more resources for New Mexico to reach 100% absolute zero carbon and ensure reliability. This results in a significant cost increase relative to the Least Cost scenario.

Nuclear ▪ Gas ST ▪ Gas CCGT ▪ Gas CT ▪ Hydrogen ▪ Net Purchases (Sales) ▪ Wind ▪ Solar ▪ BTM Solar ▪ Geothermal ▪ Battery ▪ DR

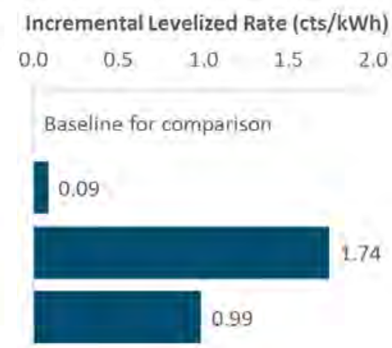
Resource Portfolios and Costs by Scenario
Separate System Planning (H_2) Scenario

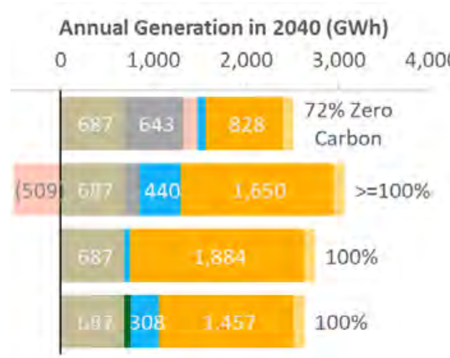
Total System





New Mexico



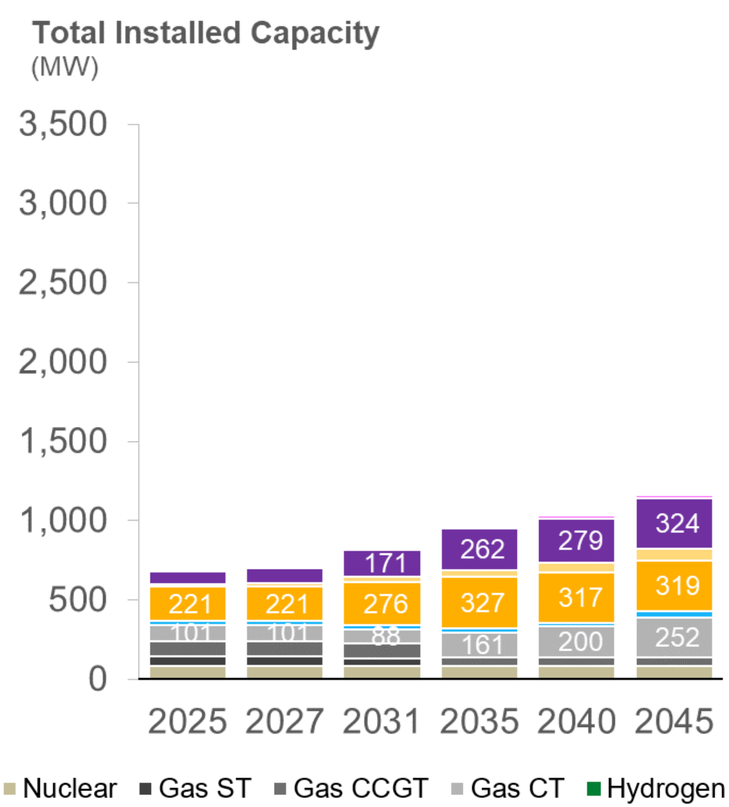


Adding H_2 capacity ensures reliability while significantly reducing solar and storage additions. This mitigates cost impacts of achieving absolute zero carbon and planning to ensure reliability independently.

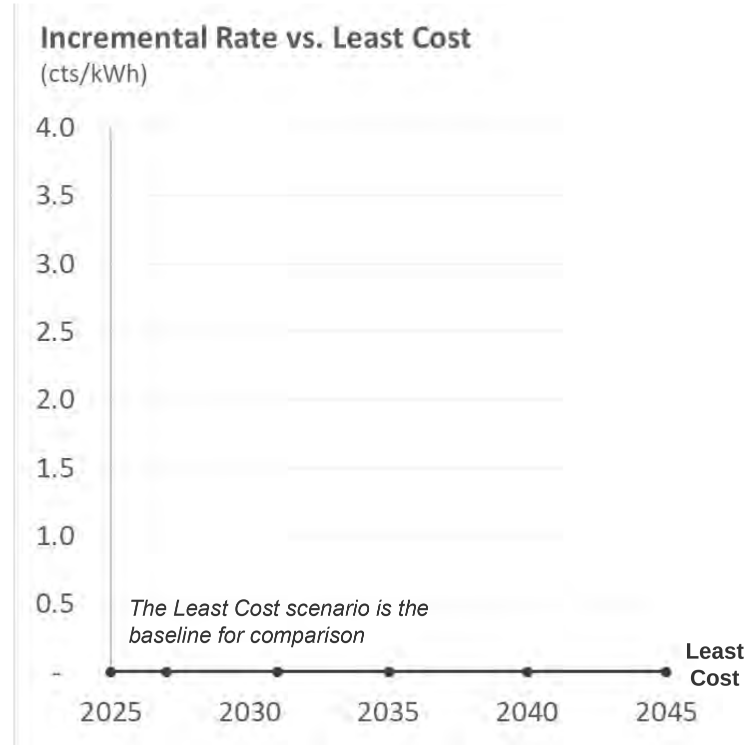
Nuclear ■ Gas ST ■ Gas CCGT ■ Gas CT ■ Hydrogen ■ Net Purchases (Sales) ■ Wind ■ Solar ■ BTM Solar ■ Geothermal ■ Battery ■ DR

New Mexico Capacity and Cost
Least Cost Scenario

Least Cost

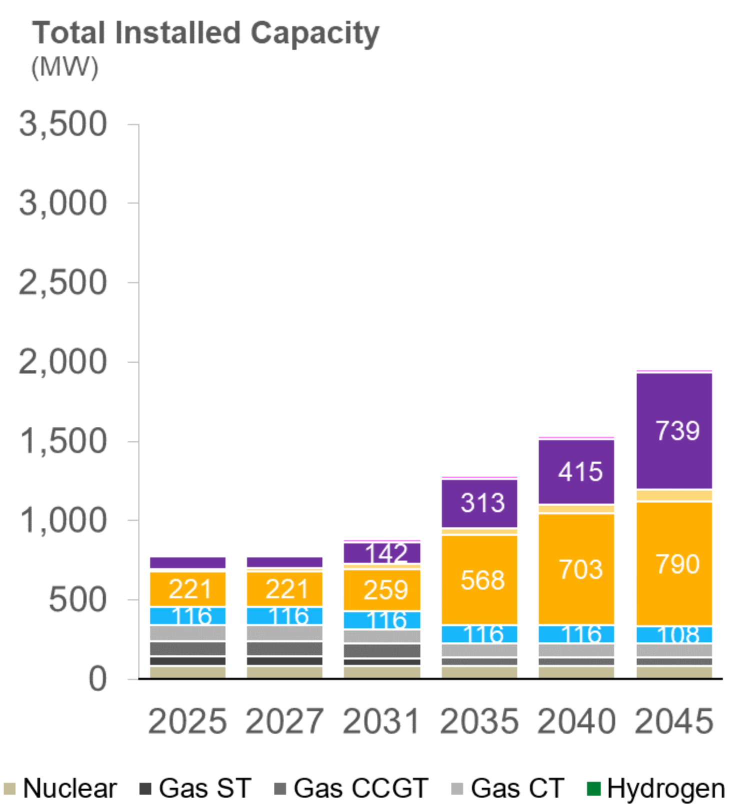


Cost Impact vs. Least Cost Scenario

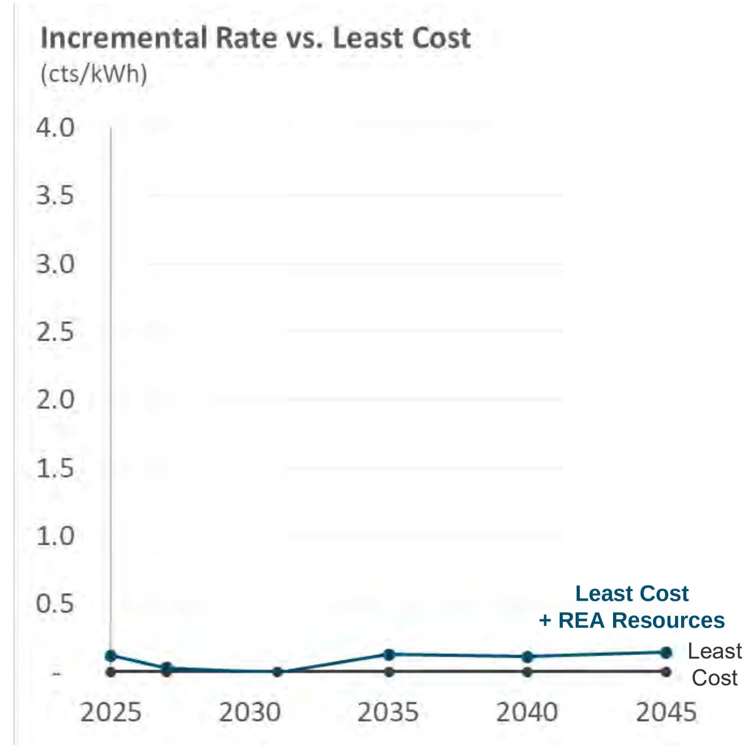


New Mexico Capacity and Cost
Least Cost + REA Resources Scenario

Least Cost + REA Resources

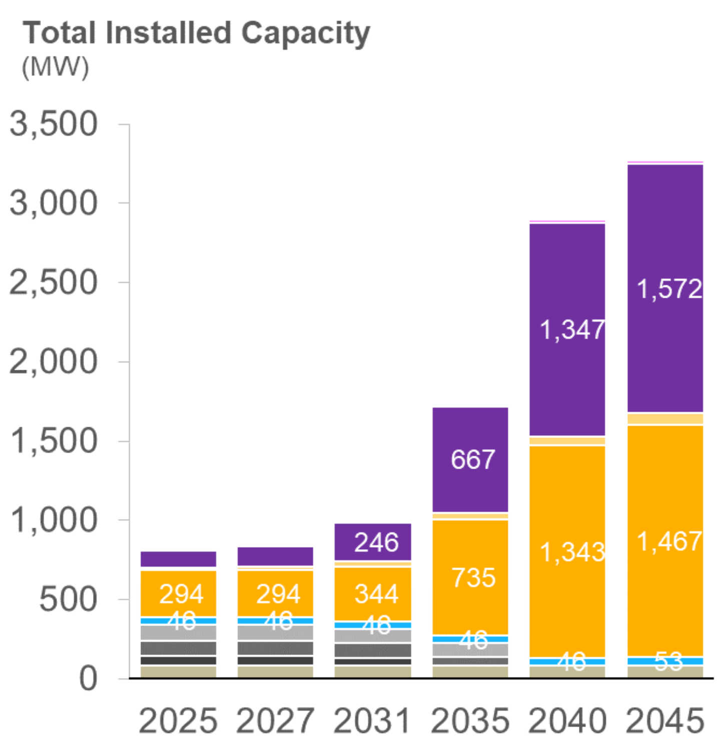


Cost Impact vs. Least Cost Scenario

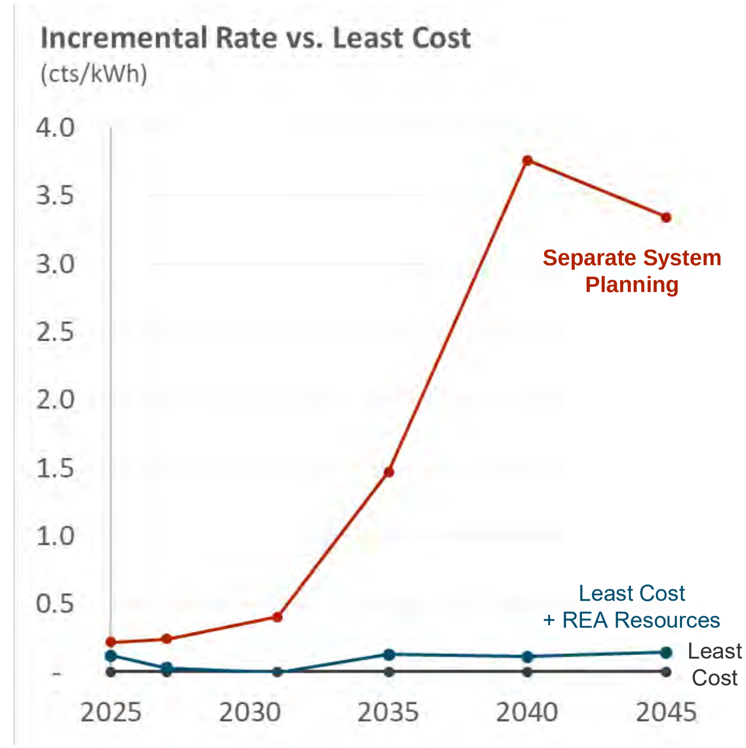


New Mexico Capacity and Cost
Separate System Planning Scenario

Separate System Planning



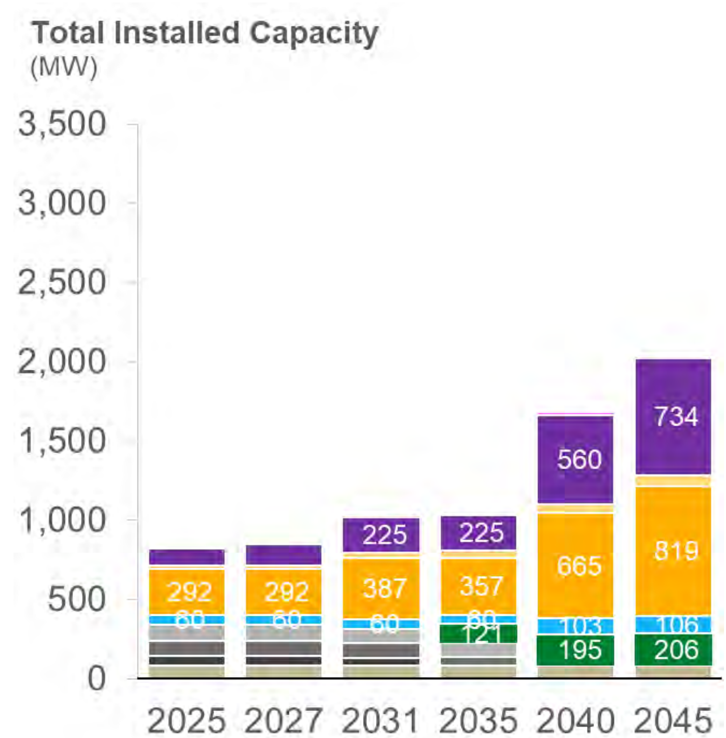
Cost Impact vs. Least Cost Scenario



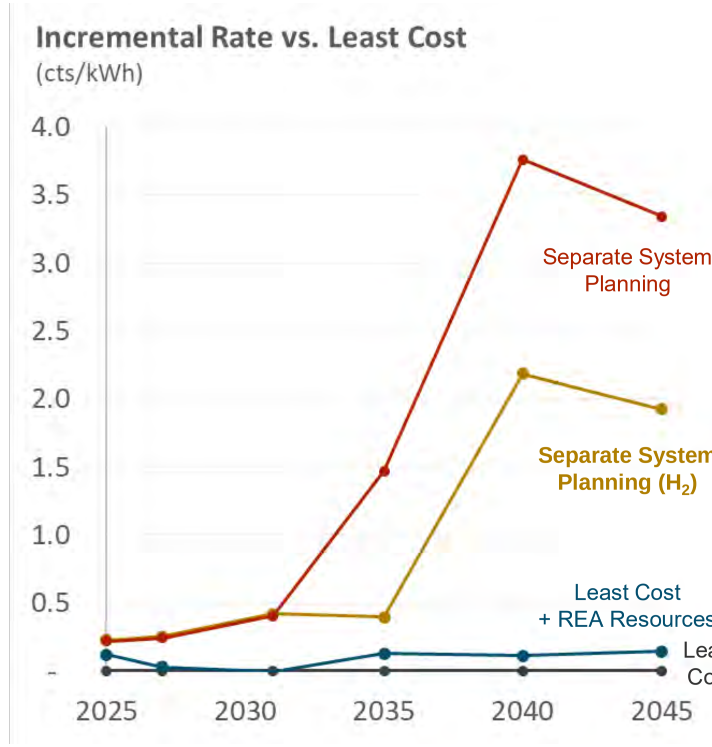
Nuclear | Gas ST | Gas CCGT | Gas CT | Hydrogen | Wind | Solar | BTM Solar | Geothermal | Battery | DR

New Mexico Capacity and Cost
Separate System Planning (H_2) Scenario

Separate System Planning (H_2)



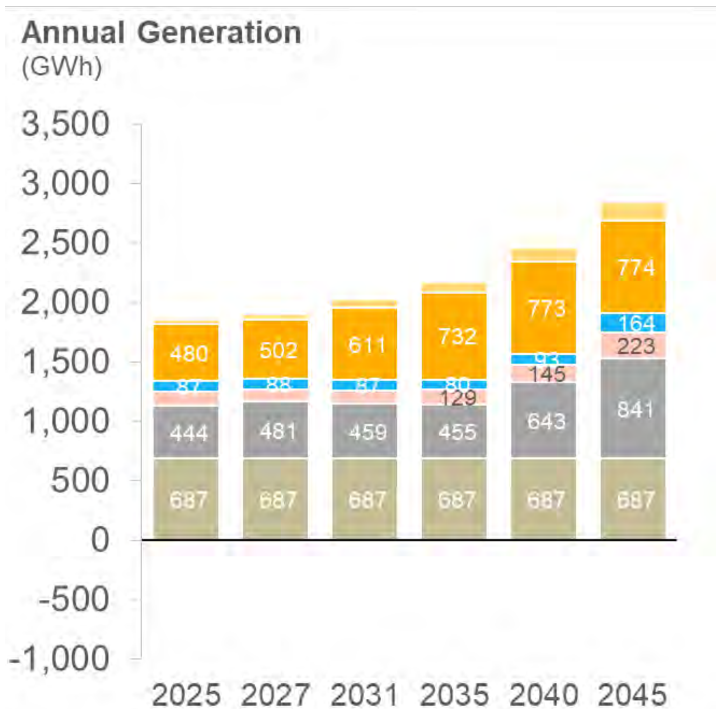
Cost Impact vs. Least Cost Scenario



Nuclear · Gas ST · Gas CCGT · Gas CT · Hydrogen · Wind · Solar · BTM Solar · Geothermal · Battery · DR

New Mexico Generation Mix
Least Cost and Least Cost + REA Scenarios

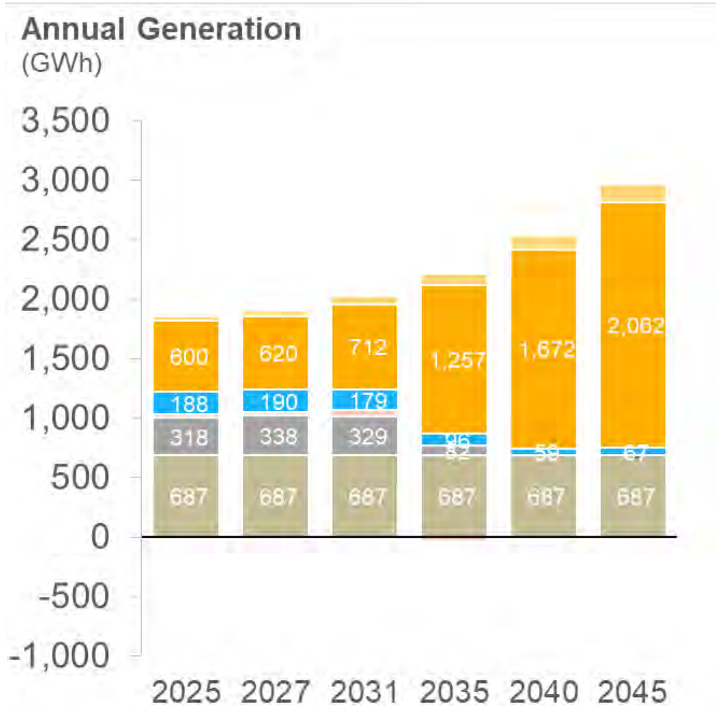
Least Cost



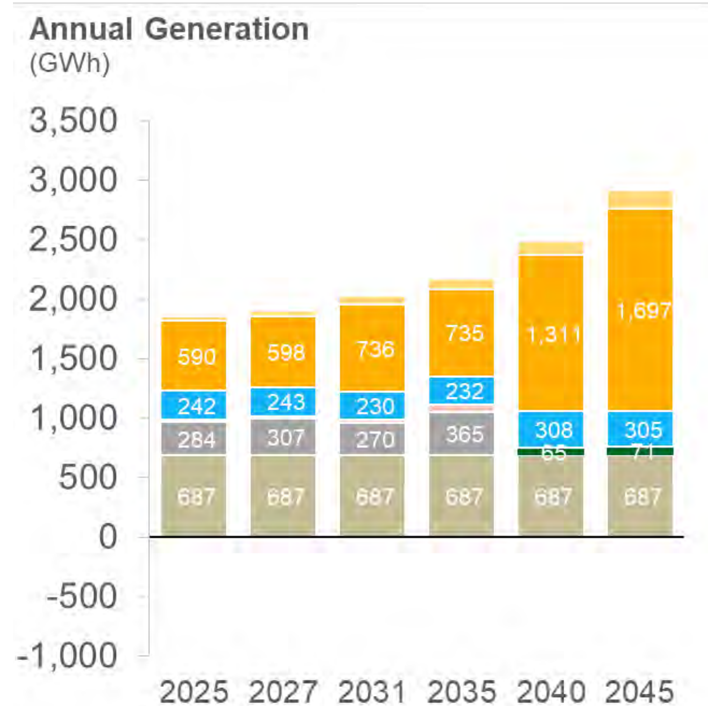
Least Cost + REA Resources

New Mexico Generation Mix
Separate System Planning Scenarios

Separate System Planning



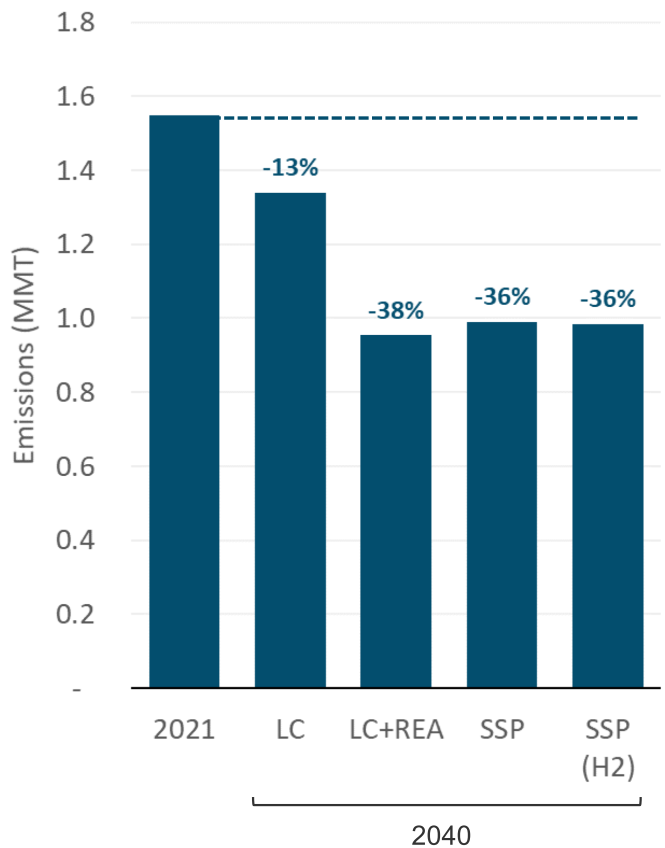
Separate System Planning (H_2)



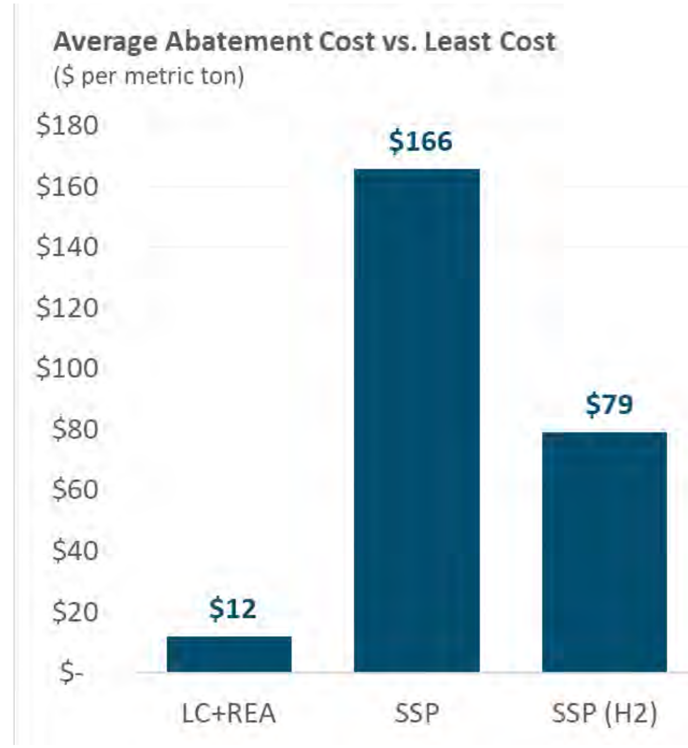
Nuclear Gas Hydrogen Net Purchases Wind Solar BTM Solar

Carbon Emissions Across Scenarios

CO_2 Emissions in 2021 and 2040



Average Abatement Cost 2025-2040



Note: emissions include emissions at company-owned facilities and emissions ascribed to imports

Energy+Environmental Economics

Thank You

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Annual Energy (GWh) 2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	8	7	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,037	1,148	1,187	1,075	1,321	1,513
	Gas - Combustion Turbine	1,027	1,169	854	925	874	767	1,251	1,657
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	354	357	361	316	381	730
	Solar	289	952	1,450	1,467	2,016	3,050	3,469	4,199
	Battery Storage	-	12	(25)	(26)	(104)	(215)	(223)	(248)
	Imports	391	336	266	261	296	278	360	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	416	397	431	636	374	456
Least-Cost Case + REA Resources	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	4	11	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	926	1,001	1,044	927	966	1,101
	Gas - Combustion Turbine	1,027	1,169	784	855	780	495	761	1,005
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	681	694	699	561	725	995
	Solar	289	952	1,340	1,356	2,030	3,274	4,121	5,334
	Battery Storage	-	12	(29)	(30)	(105)	(236)	(277)	(369)
	Imports	391	336	239	251	182	248	262	226
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	428	400	449	1,144	1,071	892
Separate System Planning	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	1	2	-	-	-	-
	Gas - Combined Cycle	1,763	1,385	1,125	1,238	1,235	1,000	1,201	1,349
	Gas - Combustion Turbine	1,048	1,180	852	922	920	502	768	1,046
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	174	175	169	76	23	398
	Solar	289	950	1,556	1,594	2,135	3,760	4,704	5,638
	Battery Storage	-	11	(55)	(62)	(129)	(300)	(367)	(423)
	Imports	391	328	291	269	301	232	229	283
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	132	304	265	365	1,270	2,517	2,452

Attachment D-3: E3 EPE Report Model Results August

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	1	2	-	-	-	-
	Gas - Combined Cycle	1,763	1,385	1,101	1,210	1,223	1,104	1,199	1,348
	Gas - Combustion Turbine	1,048	1,180	843	915	870	762	793	1,072
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	214	215	207	202	285	678
	Solar	289	950	1,551	1,588	2,173	3,139	4,241	5,147
	Battery Storage	-	11	(54)	(61)	(130)	(221)	(311)	(365)
	Imports	391	328	288	270	288	285	278	331
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	74	80
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	132	314	276	474	696	883	967
80% Clean by 2035	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	8	11	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,028	1,131	1,175	1,088	1,160	1,293
	Gas - Combustion Turbine	1,027	1,169	849	922	868	767	1,055	1,256
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	378	381	385	342	650	1,041
	Solar	289	953	1,450	1,463	2,012	3,006	3,689	4,703
	Battery Storage	-	12	(24)	(26)	(103)	(207)	(238)	(289)
	Imports	391	336	255	256	292	274	241	287
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	406	391	436	677	472	735
20% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	8	11	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,027	1,131	1,175	1,089	1,253	1,260
	Gas - Combustion Turbine	1,027	1,169	849	922	868	765	1,132	1,187
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	378	381	385	342	457	1,095
	Solar	289	953	1,442	1,456	2,012	3,007	3,621	4,792
	Battery Storage	-	12	(24)	(26)	(103)	(207)	(236)	(297)
	Imports	391	336	264	264	292	275	332	255
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	129	415	398	436	676	463	752

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Annual Energy (GWh)							
		2021	2024	2025	2027	2031	2035	2040	2045
40% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	8	11	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,027	1,131	1,175	1,089	1,060	1,028
	Gas - Combustion Turbine	1,027	1,169	849	922	868	767	790	822
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	378	381	385	342	783	961
	Solar	289	953	1,441	1,458	2,013	3,004	3,980	5,677
	Battery Storage	-	12	(24)	(26)	(103)	(207)	(264)	(396)
	Imports	391	336	264	262	292	276	210	199
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	415	396	435	680	811	1,196
60% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	12	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,001	1,093	1,143	1,029	780	735
	Gas - Combustion Turbine	1,027	1,169	840	915	852	656	453	483
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	444	448	451	388	853	808
	Solar	289	953	1,419	1,436	2,000	3,174	4,624	6,588
	Battery Storage	-	12	(25)	(26)	(101)	(226)	(312)	(488)
	Imports	391	336	259	260	286	250	161	166
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	129	411	390	452	766	1,514	1,850
80% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	4	11	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	914	986	1,049	835	531	500
	Gas - Combustion Turbine	1,027	1,169	771	842	725	399	127	142
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	722	735	743	584	1,310	1,417
	Solar	289	953	1,329	1,343	2,004	3,491	4,869	6,658
	Battery Storage	-	12	(31)	(30)	(102)	(245)	(342)	(499)
	Imports	391	336	235	251	212	208	63	73
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	444	417	491	1,350	2,580	2,939

Attachment D-3: E3 EPE Report Model Results August

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
90% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	4	11	2	-	-	-
	Gas - Combined Cycle	1,767	1,373	908	979	1,009	778	304	290
	Gas - Combustion Turbine	1,027	1,169	766	836	622	291	29	44
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	740	754	763	513	1,964	2,116
	Solar	289	952	1,325	1,339	2,154	3,842	4,535	6,263
	Battery Storage	-	12	(31)	(30)	(100)	(278)	(308)	(453)
	Imports	391	336	232	250	182	125	35	32
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	452	424	650	1,462	3,356	3,714
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	5	7	2	-	-	-
	Gas - Combined Cycle	1,767	1,373	860	928	924	643	-	-
	Gas - Combustion Turbine	1,027	1,169	715	779	558	188	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	896	917	922	557	1,629	1,685
	Solar	289	952	1,284	1,297	2,175	4,069	4,874	6,693
	Battery Storage	-	12	(31)	(32)	(97)	(302)	(345)	(509)
	Imports	391	336	215	242	148	114	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	400	423
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	528	495	798	1,795	3,187	3,597
100% CO2 Red. by 2040	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	12	2	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,013	1,110	924	643	-	-
	Gas - Combustion Turbine	1,027	1,169	843	917	558	188	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	416	419	922	557	1,992	2,629
	Solar	289	952	1,430	1,445	2,175	4,069	4,973	5,542
	Battery Storage	-	12	(25)	(26)	(97)	(302)	(406)	(572)
	Imports	391	336	260	261	148	114	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	1,455
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	412	393	798	1,795	11,640	13,062

Attachment D-3: E3 EPE Report Model Results August

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	134	31	9	12	1	-	-	-
	Gas - Combined Cycle	1,728	1,317	1,044	1,144	1,175	1,073	1,273	1,538
	Gas - Combustion Turbine	1,028	1,123	885	923	846	711	1,096	1,713
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	338	336	341	295	352	763
	Solar	285	866	1,148	1,107	1,485	2,336	2,661	2,700
	Battery Storage	-	11	(25)	(25)	(105)	(226)	(249)	(243)
	Imports	389	314	273	258	287	265	347	441
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	88	350	436	608	945	1,276	1,680	2,144
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	18	217	389	432	552	696	602	379
High DSM	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	133	30	2	3	0	-	-	-
	Gas - Combined Cycle	1,744	1,303	1,197	1,315	1,357	1,105	1,320	1,460
	Gas - Combustion Turbine	1,020	1,111	977	1,001	989	706	1,104	1,404
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	471
	Solar	288	934	1,274	1,273	1,604	2,760	3,166	3,725
	Battery Storage	-	10	(25)	(23)	(80)	(203)	(216)	(234)
	Imports	390	329	318	286	318	297	377	438
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,731	8,994	9,056	9,230	9,680	10,273	11,501	13,177
	Excess Generation	15	148	197	197	215	541	326	371
Low Load	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	101	27	2	3	2	-	-	-
	Gas - Combined Cycle	1,596	1,244	1,155	1,300	1,422	1,129	1,372	1,496
	Gas - Combustion Turbine	983	1,065	942	985	1,034	759	1,214	1,529
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	523
	Solar	282	919	1,260	1,272	1,563	2,869	3,314	3,970
	Battery Storage	-	8	(26)	(24)	(69)	(209)	(222)	(246)
	Imports	381	325	311	284	315	303	385	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,492	8,862	8,958	9,194	9,759	10,459	11,813	13,623
	Excess Generation	22	163	216	205	224	535	317	399

Attachment D-3: E3 EPE Report Model Results August

		Annual Energy (GWh)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
High Load	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	195	50	7	3	-	-	-	-
	Gas - Combined Cycle	1,909	1,522	1,077	1,166	1,126	1,113	1,386	1,518
	Gas - Combustion Turbine	1,088	1,256	889	937	786	875	1,409	1,781
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	420	424	404	387	450	957
	Solar	293	983	1,618	1,717	2,556	3,249	3,659	4,426
	Battery Storage	-	14	(42)	(64)	(158)	(220)	(224)	(251)
	Imports	400	343	275	273	281	286	373	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	9,050	9,448	9,558	9,830	10,488	11,297	12,803	14,784
	Excess Generation	10	100	381	278	543	642	387	518
No Lifetime Extensions	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	12	2	-	-	-	-
	Gas - Combined Cycle	1,767	1,373	972	1,029	1,055	1,069	1,314	1,513
	Gas - Combustion Turbine	1,027	1,169	744	693	636	764	1,246	1,657
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	364	369	340	337	408	730
	Solar	289	952	1,643	1,894	2,495	3,039	3,457	4,199
	Battery Storage	-	12	(26)	(92)	(164)	(214)	(223)	(248)
	Imports	391	336	235	243	270	276	357	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	669	413	585	637	371	456
No New Gas	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	7	12	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	1,013	1,110	1,156	829	774	714
	Gas - Combustion Turbine	1,027	1,169	843	917	859	294	269	286
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	416	419	423	227	195	209
	Solar	289	952	1,430	1,445	2,002	4,003	5,562	7,483
	Battery Storage	-	12	(25)	(26)	(102)	(320)	(460)	(623)
	Imports	391	336	260	261	293	237	219	223
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	412	393	449	1,709	2,222	2,760

Attachment D-3: E3 EPE Report Model Results August

		Annual Energy (GWh)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Low Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	127	23	4	5	1	-	-	-
	Gas - Combined Cycle	1,803	1,433	1,000	1,092	1,104	988	1,204	1,335
	Gas - Combustion Turbine	1,001	1,107	776	839	788	598	1,076	1,338
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	562	571	569	479	581	943
	Solar	289	958	1,390	1,406	1,988	3,174	3,609	4,556
	Battery Storage	-	11	(30)	(29)	(104)	(228)	(238)	(278)
	Imports	394	345	242	255	285	258	326	397
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	125	403	379	473	835	521	718
Mid Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	120	22	3	4	1	-	-	-
	Gas - Combined Cycle	1,822	1,496	923	994	1,017	922	1,107	1,275
	Gas - Combustion Turbine	983	1,036	596	663	681	475	938	1,205
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	771	794	801	650	804	1,099
	Solar	290	961	1,474	1,493	2,020	3,264	3,720	4,732
	Battery Storage	-	7	(35)	(36)	(101)	(230)	(245)	(291)
	Imports	399	354	212	227	211	190	235	273
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	121	615	574	500	912	572	727
High Carbon Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	119	21	3	3	2	-	-	-
	Gas - Combined Cycle	1,835	1,540	704	778	913	873	962	863
	Gas - Combustion Turbine	962	989	447	494	545	394	614	583
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	881	916	965	778	930	859
	Solar	290	963	1,760	1,782	2,130	3,267	4,138	6,248
	Battery Storage	-	2	(37)	(36)	(98)	(230)	(275)	(458)
	Imports	408	362	187	203	174	188	189	195
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	120	1,146	1,089	774	1,061	1,077	1,549

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Scenario	Resource Type	Annual Energy (GWh) 2021	2024	2025	2027	2031	2035	2040	2045
High Gas Price	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	125	31	6	5	1	-	-	-
	Gas - Combined Cycle	1,787	1,400	1,015	1,115	1,125	1,015	1,242	1,350
	Gas - Combustion Turbine	1,008	1,120	803	853	805	627	1,127	1,365
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	444	448	451	387	467	924
	Solar	290	956	1,419	1,435	1,998	3,161	3,603	4,486
	Battery Storage	-	9	(29)	(28)	(103)	(224)	(235)	(274)
	Imports	403	360	287	309	355	303	354	440
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	13	127	411	390	455	783	483	702
Low Renewable and Storage Costs	Nuclear (Palo Verde)	5,148	5,148	5,148	5,148	5,148	5,148	5,148	5,148
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	140	34	3	6	1	-	-	-
	Gas - Combined Cycle	1,767	1,373	984	1,068	1,096	1,000	1,220	1,278
	Gas - Combustion Turbine	1,027	1,169	842	925	824	652	1,127	1,243
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	558	564	559	474	578	1,026
	Solar	289	952	1,321	1,330	1,975	3,102	3,538	4,621
	Battery Storage	-	12	(29)	(29)	(102)	(221)	(232)	(288)
	Imports	391	336	265	275	279	262	328	411
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	37	135	165	225	344	460	601	763
	Load	8,771	9,155	9,258	9,512	10,123	10,878	12,308	14,203
	Excess Generation	14	130	324	309	486	807	490	896

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		Installed Capacity (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Least-Cost (Reference Case)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	870	1,059	1,216
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	102	102	102	102	102	197
	Solar	115	385	621	621	823	1,235	1,309	1,561
	Battery Storage	-	50	177	177	488	1,029	1,129	1,277
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + REA Resources	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	809	942	1,051
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	203	203	203	203	232	300
	Solar	115	385	544	544	795	1,414	1,693	2,037
	Battery Storage	-	50	176	177	460	1,067	1,246	1,682
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	755	755	864
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	49	49	49	49	49	161
	Solar	115	385	639	639	859	1,701	2,450	2,712
	Battery Storage	-	50	280	304	591	1,514	2,344	2,674
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	755	755	864
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	60	60	60	60	107	218
	Solar	115	385	638	638	905	1,312	1,724	2,031
	Battery Storage	-	50	278	303	570	1,057	1,496	1,797
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	123	206	212
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	910	1,022	1,149
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	185	289
	Solar	115	385	615	615	821	1,233	1,383	1,799
	Battery Storage	-	50	177	177	486	968	1,145	1,327
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
20% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	910	1,036	1,138
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	125	300
	Solar	115	385	615	615	821	1,233	1,383	1,837
	Battery Storage	-	50	177	177	486	968	1,145	1,359
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Installed Capacity (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
40% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	909	973	1,022
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	239	300
	Solar	115	385	615	615	821	1,234	1,563	2,248
	Battery Storage	-	50	177	177	486	969	1,184	1,746
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	849	892	897
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	128	128	128	128	301	302
	Solar	115	385	599	599	816	1,309	1,965	2,744
	Battery Storage	-	50	177	177	481	1,044	1,347	2,145
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	778	778	778
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	217	217	217	217	552	585
	Solar	115	385	538	538	793	1,555	2,257	3,007
	Battery Storage	-	50	176	177	458	1,097	1,645	2,461
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
90% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	726	726	726
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	224	224	224	224	801	828
	Solar	115	385	535	535	901	1,679	2,300	3,049
	Battery Storage	-	50	176	177	452	1,284	1,777	2,595
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	-	-
	Gas - Combustion Turbine	503	731	731	731	668	688	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	282	282	282	282	682	696
	Solar	115	385	512	512	925	1,801	2,403	3,178
	Battery Storage	-	50	176	177	445	1,385	1,955	2,797
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	954	954
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	688	668	668
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	120	120	282	282	1,216	1,605
	Solar	115	385	606	606	925	1,801	4,851	5,217
	Battery Storage	-	50	177	177	445	1,385	6,191	7,470
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	701
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	860	1,026	1,228
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	96	96	96	96	96	203
	Solar	115	385	511	511	684	1,010	1,107	1,018
	Battery Storage	-	50	176	176	479	1,041	1,166	1,263
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	42	169	210	293	455	614	809	1,032
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	778	942	1,058
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	128
	Solar	115	385	519	519	638	1,149	1,212	1,386
	Battery Storage	-	50	184	184	406	1,001	1,091	1,213
	Imports	-	-	-	-	-	-	-	-
	Demand Response	49	66	71	82	100	101	103	103
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	724	896	1,019
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	141
	Solar	115	385	521	521	628	1,185	1,261	1,477
	Battery Storage	-	50	186	186	355	1,019	1,121	1,262
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High Load	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	1,043	1,247	1,411
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	119	119	119	119	119	260
	Solar	115	385	662	662	1,040	1,304	1,377	1,643
	Battery Storage	-	50	235	327	708	1,042	1,142	1,292
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No Lifetime Extensions	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	234	234	144	144	-	-	-
	Gas - Combined Cycle	493	493	493	266	266	266	266	266
	Gas - Combustion Turbine	503	731	731	829	766	869	1,058	1,216
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	197
	Solar	115	385	767	767	1,027	1,229	1,302	1,561
	Battery Storage	-	50	183	432	756	1,027	1,128	1,277
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	668	668	668
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	120	120	120	120	120	132
	Solar	115	385	606	606	818	1,876	2,580	3,422
	Battery Storage	-	50	177	177	483	1,585	2,342	3,200
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Installed Capacity (MW) 2021	2024	2025	2027	2031	2035	2040	2045
Low Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	840	1,027	1,164
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	163	163	163	163	163	269
	Solar	115	385	573	573	805	1,309	1,383	1,738
	Battery Storage	-	50	176	176	470	1,044	1,145	1,314
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Mid Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	824	1,006	1,145
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	238	238	238	238	238	300
	Solar	115	385	633	633	791	1,310	1,400	1,808
	Battery Storage	-	50	176	176	456	1,045	1,149	1,334
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	817	944	944
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	300	300	300	300	300	301
	Solar	115	385	857	857	886	1,310	1,666	2,536
	Battery Storage	-	50	176	176	445	1,045	1,206	2,000
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Installed Capacity (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High Gas Price	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	848	1,036	1,170
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	128	128	128	128	128	264
	Solar	115	385	599	599	816	1,309	1,383	1,710
	Battery Storage	-	50	177	177	481	1,044	1,145	1,309
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Renewable and Storage Costs	Nuclear (Palo Verde)	622	622	622	622	622	622	622	622
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	426	307	307	307	234	-	-	-
	Gas - Combined Cycle	493	493	493	493	493	266	266	266
	Gas - Combustion Turbine	503	731	731	731	668	847	1,034	1,146
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	160	160	160	160	160	300
	Solar	115	385	525	525	806	1,277	1,351	1,805
	Battery Storage	-	50	190	190	471	1,037	1,138	1,335
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Cumulative Capacity Additions (MW) 2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	430	619	776
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	102	102	102	102	102	197
	Solar	-	270	506	506	708	1,190	1,291	1,823
	Battery Storage	-	50	177	177	488	1,029	1,129	1,327
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + REA Resources	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	369	502	611
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	203	203	203	203	232	300
	Solar	-	270	429	429	680	1,369	1,675	2,299
	Battery Storage	-	50	176	177	460	1,067	1,246	1,732
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	315	315	424
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	49	49	49	49	49	161
	Solar	-	270	524	524	744	1,656	2,432	2,974
	Battery Storage	-	50	280	304	591	1,514	2,344	2,724
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Cumulative Capacity Additions (MW) 2021	2024	2025	2027	2031	2035	2040	2045
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	315	315	424
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	60	60	60	60	107	218
	Solar	-	270	523	523	790	1,267	1,706	2,293
	Battery Storage	-	50	278	303	570	1,057	1,496	1,847
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	123	206	212
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	470	582	709
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	185	289
	Solar	-	270	500	500	706	1,188	1,365	2,061
	Battery Storage	-	50	177	177	486	968	1,145	1,377
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
20% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	470	596	698
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	125	300
	Solar	-	270	500	500	706	1,188	1,365	2,099
	Battery Storage	-	50	177	177	486	968	1,145	1,409
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Cumulative Capacity Additions (MW) 2021	2024	2025	2027	2031	2035	2040	2045
40% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	469	533	582
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	239	300
	Solar	-	270	500	500	706	1,189	1,545	2,510
	Battery Storage	-	50	177	177	486	969	1,184	1,796
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	409	452	457
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	128	128	128	128	301	302
	Solar	-	270	484	484	701	1,264	1,947	3,006
	Battery Storage	-	50	177	177	481	1,044	1,347	2,195
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	338	338	338
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	217	217	217	217	552	585
	Solar	-	270	423	423	678	1,510	2,239	3,269
	Battery Storage	-	50	176	177	458	1,097	1,645	2,511
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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		Cumulative Capacity Additions (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
90% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	286	286	286
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	224	224	224	224	801	828
	Solar	-	270	420	420	786	1,634	2,282	3,311
	Battery Storage	-	50	176	177	452	1,284	1,777	2,645
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	248	-	-
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	282	282	282	282	682	696
	Solar	-	270	397	397	810	1,756	2,385	3,440
	Battery Storage	-	50	176	177	445	1,385	1,955	2,847
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	248	248
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	248	228	228
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	120	120	282	282	1,216	1,605
	Solar	-	270	491	491	810	1,756	4,833	5,479
	Battery Storage	-	50	177	177	445	1,385	6,191	7,520
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	701
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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Scenario	Resource Type	Cumulative Capacity Additions (MW) 2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	420	586	788
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	96	96	96	96	96	203
	Solar	-	270	396	396	569	965	1,089	1,280
	Battery Storage	-	50	176	176	479	1,041	1,166	1,313
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	42	169	210	293	455	614	809	1,032
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	338	502	618
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	128
	Solar	-	270	404	404	523	1,104	1,194	1,648
	Battery Storage	-	50	184	184	406	1,001	1,091	1,263
	Imports	-	-	-	-	-	-	-	-
	Demand Response	49	66	71	82	100	101	103	103
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	284	456	579
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	141
	Solar	-	270	406	406	513	1,140	1,243	1,739
	Battery Storage	-	50	186	186	355	1,019	1,121	1,312
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Cumulative Capacity Additions (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High Load	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	603	807	971
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	119	119	119	119	119	260
	Solar	-	270	547	547	925	1,259	1,359	1,905
	Battery Storage	-	50	235	327	708	1,042	1,142	1,342
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No Lifetime Extensions	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	326	326	429	618	776
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	109	109	109	109	109	197
	Solar	-	270	652	652	912	1,184	1,284	1,823
	Battery Storage	-	50	183	432	756	1,027	1,128	1,327
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	228	228	228
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	120	120	120	120	120	132
	Solar	-	270	491	491	703	1,831	2,562	3,684
	Battery Storage	-	50	177	177	483	1,585	2,342	3,250
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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Scenario	Resource Type	Cumulative Capacity Additions (MW) 2021	2024	2025	2027	2031	2035	2040	2045
Low Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	400	587	724
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	163	163	163	163	163	269
	Solar	-	270	458	458	690	1,264	1,365	2,000
	Battery Storage	-	50	176	176	470	1,044	1,145	1,364
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Mid Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	384	566	705
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	238	238	238	238	238	300
	Solar	-	270	518	518	676	1,265	1,382	2,070
	Battery Storage	-	50	176	176	456	1,045	1,149	1,384
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	377	504	504
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	300	300	300	300	300	301
	Solar	-	270	742	742	771	1,265	1,648	2,798
	Battery Storage	-	50	176	176	445	1,045	1,206	2,050
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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		Cumulative Capacity Additions (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
High Gas Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	408	596	730
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	128	128	128	128	128	264
	Solar	-	270	484	484	701	1,264	1,365	1,972
	Battery Storage	-	50	177	177	481	1,044	1,145	1,359
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Renewable and Storage Costs	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	-	-	-	-	-	-	-
	Gas - Combined Cycle	-	-	-	-	-	-	-	-
	Gas - Combustion Turbine	-	228	228	228	228	407	594	706
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	160	160	160	160	160	300
	Solar	-	270	410	410	691	1,232	1,333	2,067
	Battery Storage	-	50	190	190	471	1,037	1,138	1,385
	Imports	-	-	-	-	-	-	-	-
	Demand Response	46	53	56	61	71	81	93	93
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	18	65	80	108	166	221	289	368
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

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		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Least-Cost Case + REA Resources	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Separate System Planning	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Cumulative Capacity Retirements (MW)							
		2021	2024	2025	2027	2031	2035	2040	2045
Separate System Planning (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% Clean by 2035	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
20% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

Scenario	Resource Type	Cumulative Capacity Retirements (MW) 2021	2024	2025	2027	2031	2035	2040	2045
40% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
60% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
80% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
90% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040 (w/ H2)	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
100% CO2 Red. by 2040	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High DG	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High DSM	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Load	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High Load	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No Lifetime Extensions	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(192)	(192)	(282)	(282)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	(227)	(227)	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
No New Gas	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

		Cumulative Capacity Retirements (MW)							
Scenario	**Resource Type**	**2021**	**2024**	**2025**	**2027**	**2031**	**2035**	**2040**	**2045**
Low Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Mid Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
High Carbon Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

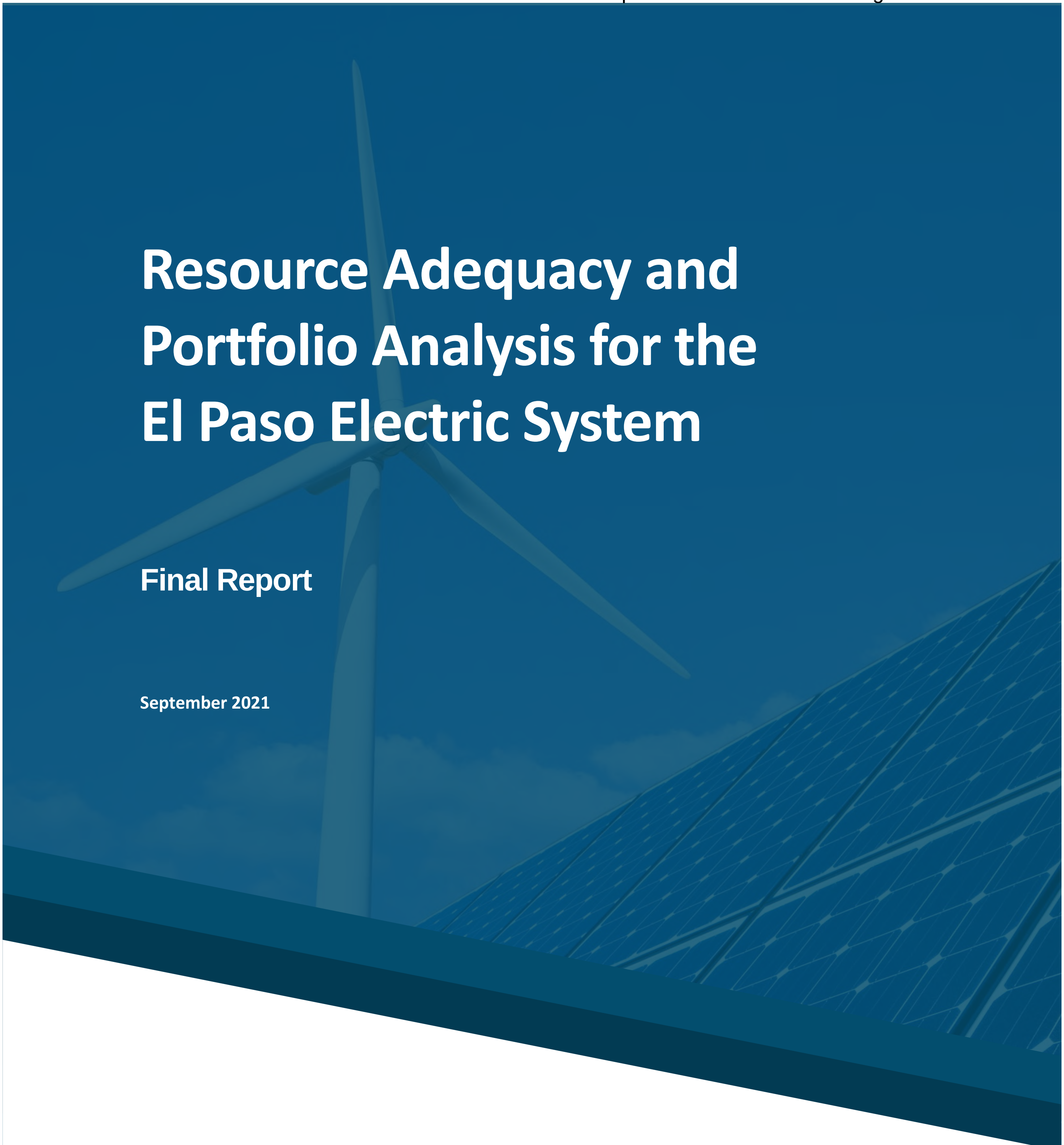
		Cumulative Capacity Retirements (MW)							
Scenario	Resource Type	2021	2024	2025	2027	2031	2035	2040	2045
High Gas Price	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-
Low Renewable and Storage Costs	Nuclear (Palo Verde)	-	-	-	-	-	-	-	-
	Nuclear (SMR)	-	-	-	-	-	-	-	-
	Gas - Steam Turbine	-	(119)	(119)	(119)	(192)	(426)	(426)	(426)
	Gas - Combined Cycle	-	-	-	-	-	(227)	(227)	(227)
	Gas - Combustion Turbine	-	-	-	-	(63)	(63)	(63)	(63)
	Biomass	-	-	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	(70)	(97)	(377)
	Battery Storage	-	-	-	-	-	-	-	(50)
	Imports	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-
	Hydrogen	-	-	-	-	-	-	-	-
	BTM Solar	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-
	Excess Generation	-	-	-	-	-	-	-	-

Attachment D-3: E3 EPE Report Model Results August

	Annual Revenue Requirement ($MM)							
Scenario	2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	$ 246	$ 233	$ 245	$ 262	$ 284	$ 340	$ 402	$ 498
Least-Cost Case + REA Resources	$ 246	$ 233	$ 247	$ 262	$ 285	$ 343	$ 406	$ 506
Separate System Planning	$ 247	$ 233	$ 250	$ 268	$ 293	$ 369	$ 473	$ 571
Separate System Planning (w/ H2)	$ 247	$ 233	$ 251	$ 268	$ 293	$ 348	$ 438	$ 536
80% Clean by 2035	$ 246	$ 233	$ 245	$ 262	$ 284	$ 342	$ 402	$ 498
20% CO2 Red. by 2040	$ 246	$ 233	$ 245	$ 262	$ 284	$ 342	$ 402	$ 499
40% CO2 Red. by 2040	$ 246	$ 233	$ 245	$ 262	$ 284	$ 342	$ 405	$ 512
60% CO2 Red. by 2040	$ 246	$ 233	$ 246	$ 262	$ 284	$ 341	$ 419	$ 531
80% CO2 Red. by 2040	$ 246	$ 233	$ 247	$ 262	$ 284	$ 347	$ 463	$ 577
90% CO2 Red. by 2040	$ 246	$ 233	$ 247	$ 263	$ 287	$ 357	$ 500	$ 615
100% CO2 Red. by 2040 (w/ H2)	$ 246	$ 233	$ 249	$ 264	$ 289	$ 367	$ 551	$ 663
100% CO2 Red. by 2040	$ 246	$ 233	$ 245	$ 262	$ 289	$ 367	$ 1,113	$ 1,282
High DG	$ 245	$ 231	$ 241	$ 256	$ 277	$ 325	$ 382	$ 470
High DSM	$ 245	$ 230	$ 239	$ 254	$ 271	$ 313	$ 367	$ 450
Low Load	$ 239	$ 227	$ 236	$ 252	$ 269	$ 312	$ 371	$ 460
High Load	$ 253	$ 239	$ 255	$ 276	$ 307	$ 374	$ 441	$ 540
No Lifetime Extensions	$ 246	$ 228	$ 243	$ 266	$ 298	$ 344	$ 406	$ 502
No New Gas	$ 246	$ 233	$ 245	$ 262	$ 284	$ 367	$ 453	$ 570
Low Carbon Price	$ 291	$ 277	$ 284	$ 301	$ 323	$ 379	$ 444	$ 543
Mid Carbon Price	$ 358	$ 341	$ 341	$ 358	$ 381	$ 436	$ 505	$ 611
High Carbon Price	$ 469	$ 449	$ 432	$ 451	$ 475	$ 529	$ 603	$ 718
High Gas Price	$ 257	$ 242	$ 251	$ 268	$ 291	$ 347	$ 412	$ 509
Low Renewable and Storage Costs	$ 246	$ 233	$ 240	$ 256	$ 274	$ 321	$ 379	$ 463

Attachment D-3: E3 EPE Report Model Results August

Scenario	Clean Energy Type	Clean Energy (% of Load) 2021	2024	2025	2027	2031	2035	2040	2045
Least-Cost (Reference Case)	Renewable %	4%	12%	21%	21%	27%	34%	36%	39%
	Zero Carbon %	62%	68%	77%	75%	77%	81%	77%	75%
Least-Cost Case + REA Resources	Renewable %	4%	12%	24%	24%	30%	39%	43%	49%
	Zero Carbon %	62%	68%	79%	78%	80%	85%	84%	84%
Separate System Planning	Renewable %	4%	12%	20%	21%	26%	38%	42%	46%
	Zero Carbon %	62%	68%	76%	75%	76%	84%	83%	82%
Separate System Planning (w/ H2)	Renewable %	4%	12%	21%	21%	27%	34%	41%	45%
	Zero Carbon %	62%	68%	76%	75%	77%	81%	82%	81%
80% Clean by 2035	Renewable %	4%	12%	21%	22%	27%	34%	39%	45%
	Zero Carbon %	62%	68%	77%	76%	77%	81%	80%	80%
20% CO2 Red. by 2040	Renewable %	4%	12%	21%	22%	27%	34%	37%	46%
	Zero Carbon %	62%	68%	77%	76%	77%	81%	78%	81%
40% CO2 Red. by 2040	Renewable %	4%	12%	21%	22%	27%	34%	43%	51%
	Zero Carbon %	62%	68%	77%	76%	77%	81%	84%	86%
60% CO2 Red. by 2040	Renewable %	4%	12%	22%	22%	27%	36%	48%	56%
	Zero Carbon %	62%	68%	77%	76%	78%	83%	89%	91%
80% CO2 Red. by 2040	Renewable %	4%	12%	24%	24%	30%	41%	54%	60%
	Zero Carbon %	62%	68%	79%	78%	81%	87%	94%	95%
90% CO2 Red. by 2040	Renewable %	4%	12%	24%	24%	32%	43%	56%	62%
	Zero Carbon %	62%	68%	79%	78%	82%	89%	97%	98%
100% CO2 Red. by 2040 (w/ H2)	Renewable %	4%	12%	25%	26%	34%	45%	56%	62%
	Zero Carbon %	62%	68%	81%	79%	84%	92%	100%	100%
100% CO2 Red. by 2040	Renewable %	4%	12%	22%	22%	34%	45%	60%	65%
	Zero Carbon %	62%	68%	77%	76%	84%	92%	100%	100%
High DG	Renewable %	4%	13%	21%	22%	27%	35%	37%	39%
	Zero Carbon %	63%	70%	76%	75%	77%	82%	78%	74%
High DSM	Renewable %	4%	12%	16%	16%	20%	31%	32%	37%
	Zero Carbon %	63%	69%	73%	72%	73%	80%	76%	75%
Low Load	Renewable %	4%	12%	16%	16%	19%	31%	33%	38%
	Zero Carbon %	64%	70%	73%	72%	72%	79%	75%	75%
High Load	Renewable %	4%	12%	23%	24%	31%	36%	36%	41%
	Zero Carbon %	61%	66%	77%	76%	79%	80%	76%	75%
No Lifetime Extensions	Renewable %	4%	12%	23%	26%	31%	35%	36%	39%
	Zero Carbon %	62%	68%	79%	80%	81%	81%	77%	75%
No New Gas	Renewable %	4%	12%	22%	22%	27%	42%	50%	57%
	Zero Carbon %	62%	68%	77%	76%	77%	88%	90%	92%
Low Carbon Price	Renewable %	4%	12%	23%	23%	28%	37%	38%	43%
	Zero Carbon %	62%	68%	78%	77%	79%	83%	79%	79%
Mid Carbon Price	Renewable %	4%	12%	26%	26%	31%	39%	41%	45%
	Zero Carbon %	62%	68%	81%	80%	81%	86%	82%	81%
High Carbon Price	Renewable %	4%	12%	30%	31%	34%	41%	45%	54%
	Zero Carbon %	62%	68%	86%	85%	84%	87%	86%	89%
High Gas Price	Renewable %	4%	12%	22%	22%	27%	36%	37%	43%
	Zero Carbon %	62%	68%	77%	76%	78%	82%	78%	78%
Low Renewable and Storage Costs	Renewable %	4%	12%	22%	22%	28%	36%	38%	44%
	Zero Carbon %	62%	68%	77%	76%	78%	83%	79%	80%



Resource Adequacy and Portfolio Analysis for the El Paso Electric System

Final Report

September 2021

Energy+Environmental Economics

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Acronym and Abbreviation Definitions

Acronym	Definition
ABQ	Albuquerque
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BTM	Behind-the-meter
COD	Commercial Operation Date
CO_2	Carbon Dioxide
CC	Combined Cycle
CT	Combustion Turbine
DAFOR	Derated Adjusted Forced Outage Rate
DG	Distributed Generation
DR	Demand Response
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
EP	El Paso
EPE	El Paso Electric
EUE	Expected Unserved Energy
EV	Electric Vehicle
Geo	Geothermal
GHG	Greenhouse Gas
H_2	Hydrogen
ICAP	Installed Capacity
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
LC	Least-Cost
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTO	Loss to Others
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt-hour
NM	New Mexico
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PCAP	Perfect Capacity
PRM	Planning Reserve Margin
PV	Photovoltaic or Present Value
REA	Renewable Energy Act
RTO	Regional Transmission Organization

SSP	Separate System Planning
ST	Steam Turbine
TX	Texas
UCAP	Unforced Capacity

Executive Summary

This study by Energy and Environmental Economics, Inc. (E3) details analysis that E3 performed to support the El Paso Electric Company's (EPE or El Paso Electric) 2021 Integrated Resource Plan (IRP) filing. E3 utilized its modeling software in combination with E3-developed inputs and inputs provided by El Paso Electric to identify optimal long-term resource portfolios for the period through 2045. El Paso Electric utilized these portfolio results directly in its IRP filing.

El Paso Electric is an electric utility providing generation, transmission, and distribution service to customers in southern New Mexico and western Texas. Customers in New Mexico account for approximately 20% of its system load. E3 developed optimal long-term resource portfolios for the entire system that minimize cost while ensuring compliance with all New Mexico and Texas policy requirements and maintaining reliability for all customers.

There are several factors that drive El Paso electric's long-term resource needs. El Paso Electric has several thermal units that are scheduled to retire over the next two decades. In addition, El Paso Electric expects continued growth in load, which together with resource retirements, drives a need for new resources to ensure reliability for customers. Maintaining reliability has always been paramount for long-term resource planning, but its importance has been underlined by recent widespread outage events in other parts of Texas and in California.

Another factor driving long-term planning is the change in market conditions. Over the next two decades, El Paso Electric expects gas prices to rise and the cost of renewable and storage resources to fall. These trends impact the optimal mix of generating resources over time. In addition, El Paso Electric must add renewable and zero-carbon resources to comply with clean energy policies in New Mexico and Texas. Notably, the New Mexico Renewable Energy Act (REA), as amended since El Paso Electric's previous IRP, requires El Paso Electric to supply New Mexico customers with a growing share of renewable energy and to supply New Mexico customers with 100% zero-carbon energy by 2045.

El Paso Electric already has a less carbon intensive portfolio than most other utilities, given its reliance on energy from nuclear, natural gas, and renewable energy sources. E3 estimates that El Paso Electric's current energy supply for retail customers in New Mexico and Texas is made up of more than 60% zero-carbon energy. Between now and 2023, El Paso Electric will add 270 MW of additional solar resources and 50 MW of paired battery storage to its system. Given the factors highlighted above, El Paso Electric will continue adding more renewable resources, which will cause the share of zero-carbon energy on its system to grow over time.

In this study, E3 utilized robust modeling tools and industry best practices to quantify future system needs and develop optimal least-cost resource portfolios. E3 performed four analyses:

1. **Planning reserve margin (PRM)** – Quantification of the PRM that is required to maintain resource adequacy and ensure reliability for the system.
2. **Effective load carrying capability (ELCC)** – Quantification of the contribution of resources – both existing and new – toward the PRM requirement for ensuring reliability.

3. **Portfolio analysis** – Identification of long-term resource additions that minimize cost while ensuring reliability and satisfying New Mexico and Texas clean energy requirements.
4. **Sensitivity analysis** – Assessment of changes to the portfolio that would result from changes to key planning assumptions.

The results of these analyses are summarized below.

Planning Reserve Margin (PRM)

The use of a PRM requirement to determine resource adequacy needs is common among utilities and grid operators throughout the industry. Starting in 2025, El Paso Electric plans to meet a 2-day-in-10-year (0.2 loss of load expectation, or 0.2 LOLE) reliability standard, meaning that there can be up to two days per year with outages, on average. Starting in 2030, El Paso Electric plans to meet a 1-day-in-10-year (0.1 LOLE) reliability standard, meaning there can be up to one day per year with outages, on average. The 0.1 LOLE reliability standard is more common practice in the industry for long-term resource planning.

To quantify the PRM requirement needed to meet this standard, E3 utilized its RECAP model, a loss-of-load probability (LOLP) model that has been used to evaluate the resource adequacy of electric systems across North America, including in California, Nevada, the Pacific Northwest, Montana, the Upper Midwest, and Canada. RECAP simulates resource availability for the electric system with a specific set of generating resources and loads under a wide variety of weather conditions, incorporating weather-matched load and renewable profiles, time-sequential dispatch logic for energy storage, and stochastic forced outages of generation resources. By simulating the system under hundreds of years' worth of conditions with different combinations of these factors, RECAP provides a statistically robust estimation of the PRM required to meet a reliability standard. Table ES-1 shows the PRM results for the El Paso Electric system.

Table ES-1. Planning Reserve Margin Requirements

Metric	Units	2025	2030
Loss of Load Expectation (LOLE)	days/yr	0.2	0.1
Expected System Median Peak	MW	2,245	2,420
Planning Reserve Margin	%	10%	13%
Total Perfect Capacity Need	MW	2,470	2,735

The quantification of the PRM depends on the accounting framework that's used for counting contributions of resources toward the PRM. In this study, E3 utilized a perfect capacity (PCAP) accounting framework, meaning that all resources – including renewable, storage, demand response, and thermal resources – are counted toward the PRM based on their effective load carrying capability (ELCC).

Effective Load Carrying Capability (ELCC)

ELCC has been increasingly recognized by the industry as the preferred method for measuring resources' firm capacity contribution to system reliability. E3 used RECAP to quantify ELCCs by evaluating how much firm capacity a resource can displace to maintain the desired LOLE targets. By simulating the EPE system across a wide range of potential system conditions, RECAP captures the limitations of resources and quantifies their contribution towards resource adequacy. E3 utilized the ELCC results to measure each resource's contribution toward the PRM within the portfolio analysis.

Portfolio Analysis

After quantifying the PRM requirement and resource ELCCs, E3 performed resource portfolio optimization using its RESOLVE model. RESOLVE is an electricity system capacity expansion model that identifies economically optimal long-term resource and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios and is specifically designed to simulate power systems operating under high penetrations of renewable energy and energy storage resources.

The study considers several resource options for meeting future resource needs. The study includes a range of renewable resource options, including solar photovoltaic (at nine potential locations), wind (at three potential locations), geothermal (at two potential locations), and biomass. The study also includes the option to select transmission upgrades to deliver energy from remote renewable resources. In addition to renewable resources, the study considers storage, combustion turbine, and demand resource options to meet future needs. For five existing thermal units that are scheduled to retire in the near-term, the study considers the option to extend their lifetimes by five years.

One of the key modeling constraints is ensuring that El Paso Electric's future resource portfolio complies with clean energy requirements in New Mexico and Texas while ensuring fair cost allocation between the two jurisdictions. Compared to the Texas renewable energy requirement, the New Mexico REA is more stringent, requiring an increasing share of retail sales to be supplied by renewable sources and requiring 100% of retail sales to be supplied by zero-carbon energy sources by 2045. If there are incremental costs associated with satisfying the New Mexico REA, then those costs must be allocated to New Mexico.

E3's analysis includes four cases that use different approaches to model a portfolio that satisfies the REA requirements:

1. **Least-Cost (LC)** – This case does not impose any constraints on the resource portfolio beyond reliability requirements.
2. **Least-Cost + REA Resources (LC+REA)** – This case reoptimizes the portfolio of the Least-Cost case to add additional renewables and storage resources dedicated to serving New Mexico customers to satisfy New Mexico's REA requirements.
3. **Separate System Planning (SPP)** – This case models the New Mexico and Texas systems independently without allowing interactions between them.

In addition, E3 modeled another separate system planning case (SPP H2) in which hydrogen generation is available for selection as a zero-carbon firm resource on the system. More information on these cases can be found in Table ES-2.

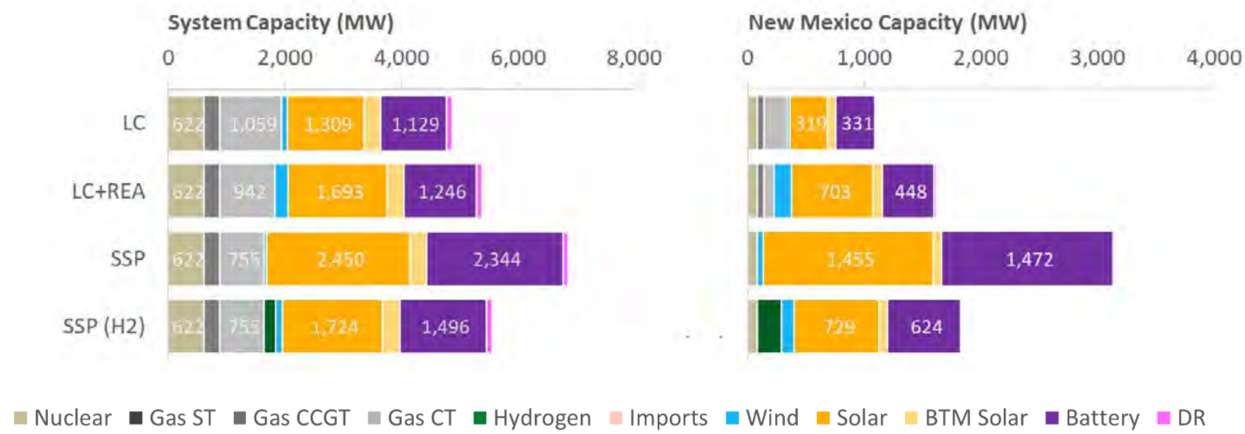
Table ES-2. REA Cases Analyzed

	Least-Cost ("LC")	Least-Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio Optimization	Least-cost system optimization	Reoptimize Least-Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM Zero-Carbon Generation Balancing Period	Annual	Annual	Hourly
NM and TX Capacity Pooling to Ensure Reliability	✓	✓	✗
Resource Allocation	Resources allocated proportionally	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM Allocated New Gas Capacity	✓	✗	✗

Figure ES-1 shows the overall resource capacity in 2040 for each REA case. Renewable, storage, or demand response resources account for most resource additions in the LC case. Gas capacity is also added to ensure reliability. Compared to the LC case, the LC+REA case adds more solar, storage, and wind resources that were not selected in the LC case but are added as dedicated New Mexico resources to meet REA targets in the LC+REA case. This additional renewable and storage procurement reduces the amount of gas resources needed for meeting reliability needs. By 2040, gas resources help ensure reliability for New Mexico customers but are rarely dispatched, enabling the New Mexico portfolio to produce zero-carbon energy serving at least 100% of retail sales on an annual basis. Section 6.4.2 discusses these results in more detail.

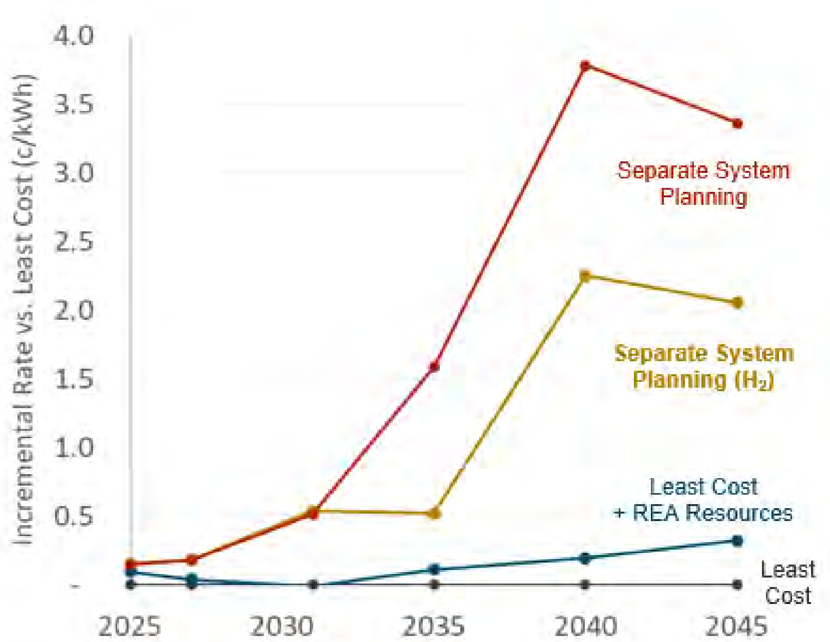
The SPP case procures significantly more solar and storage resources, which are needed to enable the New Mexico separate system to balance on an hourly basis without any gas generation, as well as to meet reliability needs as a standalone system without capacity pooling. These incremental resources and associated costs are assigned to New Mexico customers. The addition of a moderate amount of zero-carbon dispatchable hydrogen generation to the New Mexico separate system in the SSP H2 case significantly reduces the amount of solar and storage required compared to the SSP case, because the H2 generation can cover the infrequent longer-duration events that are challenging for reliability on the New Mexico separate system.

Figure ES-1. Capacity in 2040 by REA Case



See Figure ES-2 for the cost impact by year for New Mexico customers for each of the REA cases evaluated. All cost impacts are calculated based on the difference in annual cost for New Mexico customers relative to the Least-Cost case, divided by the annual New Mexico retail sales (in kWh). This gives an incremental rate impact (in cents/kWh) for New Mexico customers.

Figure ES-2. New Mexico Customer Rate Impact Relative to Least-Cost Case



The LC case is shown with zero incremental cost in all years, as it is the baseline for comparison. Notably, the LC+REA case has an incremental cost that is only 0.2 cents per kWh more than the LC case in 2040. By contrast, the SSP case is the most expensive case modeled, with an incremental cost for New Mexico customers of 0.5 cents per kWh in 2030, and over 3.5 cents per kWh by 2040 compared to the LC case. In this case, the significant additional storage and solar required to ensure reliability without capacity pooling and without any gas generation in any hour results in a significant increase in costs.

Adding the option to burn green hydrogen in the SSP H2 case substantially moderates the cost increase compared to the SSP case after 2030, because dispatchable hydrogen-fired generation is a lower-cost option compared with the very large solar and storage builds in the SSP case for meeting New Mexico's reliability needs with zero-carbon sources in all hours. The cost impact reduction provided by adding a hydrogen fuel option is most pronounced in 2040 and 2045, when the clean energy targets are highest and the implied cost of the SSP case is highest. Even with the hydrogen option, the SPP H2 case is still higher in cost than the LC+REA case. This comparison indicates that significant cost efficiency can be gained from capacity pooling and annual zero-carbon balancing (rather than hourly).

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. Sensitivity cases analyzed in this study include different assumptions for load growth, demand-side resource growth, gas resource availability, fuel prices, carbon pricing, renewable and storage technology costs, and carbon reduction targets.

Among the sensitivities, the most significant deviations from the Least-Cost case occur in the cases with more stringent carbon reduction targets. At lower carbon reduction targets, the changes to the portfolio and the impacts to cost are small. As the carbon reduction target approaches 100% by 2040, the changes are more significant. For example, to achieve a 100% carbon reduction target by 2040 relying only on renewable and storage resources, El Paso Electric must build significant amounts of renewable and storage resources to eliminate all carbon emissions while ensuring reliability. The rate impact in 2040 for this sensitivity is 5.8 cents per kWh. If El Paso Electric can utilize turbines fueled by green hydrogen as a zero-carbon resource, then the rate impact drops to 1.2 cents per kWh, as less renewable and storage resources are needed to achieve the same carbon reduction and reliability levels.

Key Findings

The following are key findings in this study:

+ For the El Paso Electric system, a PRM of 10% is needed to ensure a 2-day-in-10-year reliability standard, or 0.2 LOLE, in 2025. A PRM of 13% is needed to ensure a 1-day-in-10-year reliability standard, or 0.1 LOLE, in 2030 and beyond.
+ Storage, renewable, and demand response resources can contribute meaningfully toward the PRM requirement, but their contributions decline as their penetration levels increase. Solar can mitigate ELCC declines for storage, and vice versa, as the two resources can together help meet daytime and nighttime reliability needs.

+ Solar and storage resources account for the largest share of resource additions in optimal long-term resource portfolios. Solar is a low-cost resource, while storage helps with integrating solar resources and meeting nighttime energy needs. Wind, demand response, and gas resource additions also contribute to future system needs.

+ Different approaches to modeling the New Mexico REA result in different portfolios and costs to New Mexico customers. Across the three approaches analyzed in this study, separate system planning results in the biggest rate impact to New Mexico customers because they do not reap the benefits of balancing loads and resources within a larger planned system. The Least-Cost + REA case has a much smaller rate impact and, unlike the Least-Cost case, does not allocate any new gas resource costs to New Mexico customers.

+ Without the option to add new firm zero-carbon resources, such as plants that burn green hydrogen, achieving deep decarbonization levels across the entire El Paso Electric system – such as greater than 90% carbon emission reductions – requires substantial renewable and storage additions, resulting in a high impact on total cost and customer rates.

1 Introduction

1.1 Purpose of Study

In this study, E3 performed analysis to support El Paso Electric's 2021 Integrated Resource Plan (IRP) filing. E3 utilized its proprietary modeling software in combination with E3-developed inputs and inputs provided by El Paso Electric to identify optimal long-term resource portfolios. El Paso Electric utilized these portfolio results directly in its IRP filing.

1.2 Scope of Analysis

In this study, E3 performed four analyses:

1. **Planning reserve margin (PRM)** – Quantification of the PRM that is required to maintain resource adequacy and ensure reliability for the system.
2. **Effective load carrying capability (ELCC)** – Quantification of the contribution of resources – both existing and new – toward the PRM requirement for ensuring reliability.
3. **Portfolio analysis** – Identification of long-term resource additions that minimize cost while ensuring reliability and satisfying New Mexico and Texas clean energy requirements.
4. **Sensitivity analysis** – Assessment of changes to the portfolio that would result from changes to key planning assumption.

The PRM and ELCC results feed directly into the resource portfolio analyses and serve as the basis for ensuring resource adequacy.

1.3 Resource Adequacy

The ability to provide reliable electric service is a fundamental requirement for utilities. Electricity permeates modern society, providing essential services throughout all sectors of the economy. When the reliability of an electric system is compromised, the consequences can be dire. The outages that occurred in other parts of Texas in February 2021 provide a powerful example of how failure to maintain reliability can impose significant costs on society and, in extreme cases, result in loss of life. "Resource adequacy" is the ability of an electric power system's resources – including generation, storage, and demand response – to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard.

No electricity system is perfectly reliable; there is always some chance that generator failures and/or extreme weather conditions impacting supply and demand could compound on one another to result in loss of load. The resource adequacy of a system thus depends on the characteristics of its load – seasonal patterns, weather sensitivity, hourly patterns – as well as its resources – size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources. Ensuring an appropriate level of resource adequacy is an important goal for utilities seeking to provide both reliable and affordable service to their customers.

Resource adequacy can be measured using a variety of statistical metrics that describe the expected frequency, duration, and magnitude of loss of load events that may occur when available generation is insufficient to meet system needs. While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. Today, most utilities in the United States use a “one day in ten year” standard, which allows for up to one day with outages every ten years on average.

1.3.1 Planning Reserve Margin

To maintain resource adequacy, most utilities rely on a planning reserve margin (PRM) requirement, which establishes the total need for capacity as a function of the system’s expected peak demand. By maintaining a margin of capacity above expected peak demands, this approach has allowed utilities to supply loads reliably under most circumstances despite the potential for extreme loads, generator outages, and other factors that limit the availability of supply.

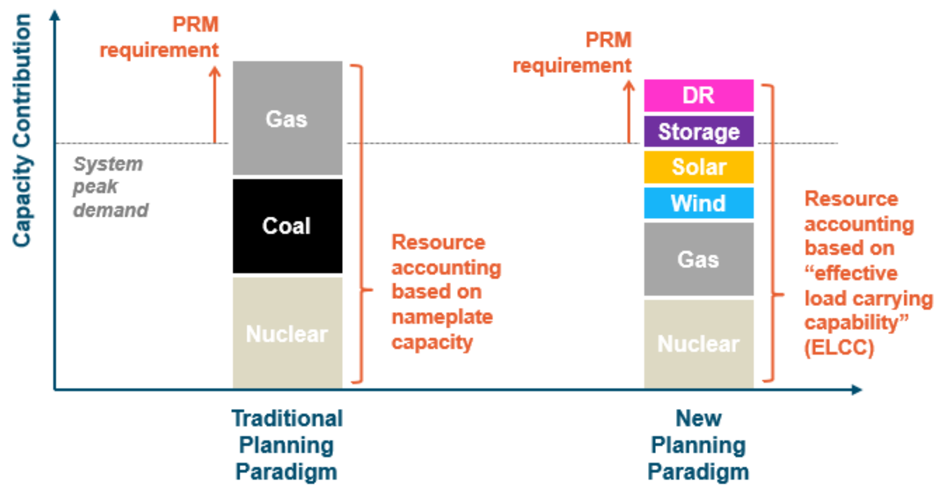
PRM requirements currently in use across the industry vary considerably across utilities. While different methods have been used to derive PRM requirements, the industry best practice for resource adequacy is to use a loss of load probability (LOLP) model to determine a system’s PRM requirement so that it is aligned with a statistical standard for reliability. LOLP models simulate the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven load variability, forced outages of power plants, the natural variability of resources like wind and solar PV, and operating constraints for resources like hydro and storage.

1.3.2 Resource Accounting Conventions

Historically, to satisfy the PRM and ensure resource adequacy, most utilities have relied primarily on firm resources – resources that can dispatch when needed and for any duration of time. However, utilities are increasingly adding and relying on dispatch-limited resources – such as solar, wind, geothermal, energy storage, and demand response – whose ability to generate varies based on time of day, season, state of charge, or other factors.

Figure 1-1 shows the shift in planning paradigm from one that relies predominantly on firm resources to one that relies increasingly on dispatch-limited resources. Under both paradigms, the contribution of resources toward the PRM, or their capacity contribution, must be sufficient to ensure resource adequacy. Under the traditional paradigm, resources count toward the PRM based on their nameplate capacities. When all resources on a system are firm, this does not pose problem. However, this convention does not work well for dispatch-limited resources that cannot produce at maximum output on demand. Under the new paradigm, dispatch-limited resources are counted based on the effective load carrying capability (ELCC) metric, which appropriately accounts for their contribution toward the PRM, or capacity value. This ensures that, when all resources’ capacity contributions are added together and the PRM is met, the system will satisfy the reliability target. As discussed below, the PRM requirement depends in part on the convention used to account for different resources' capacity contributions.

Figure 1-1. Illustrative Industry Planning Paradigm for Planning Reserve Margin



Utilities and other planning entities use different conventions for determining the capacity contribution of resources toward the PRM:

+ **Dispatch-limited resources:**

  1) Effective load carrying capability: The capacity contribution is determined based on rigorous loss-of-load probability modeling, as described in Section 1.3.3. This metric is the most accurate measure of a resource's contribution to the PRM.
  2) Other metrics: The capacity contribution is based on heuristics, such as average generation during specific time windows or rules of thumb for storage duration, which are less accurate than the effective load carrying capability method.

+ **Firm resources:**

  1) Effective load carrying capability: The capacity contribution is determined based on rigorous loss-of-load probability modeling, as described in Section 1.3.3. Because of forced outage rates, the capacity contribution is less than the rated capacity of the resource.
  2) Unforced capacity: The capacity contribution is equivalent to the rated capacity of the resource multiplied by one minus the forced outage rate.
  3) Rated capacity: The capacity contribution is equivalent to the rated capacity of the resource.

For dispatch-limited resources, the effective load carrying capability is the most accurate way to quantify the capacity contribution. For firm resources, there are three options for determining the capacity contribution: effective load carrying capability, unforced capacity, and rated capacity. If firm resources are counted toward the PRM based on their effective load carrying capability, then the PRM that satisfies the reliability target is considered a perfect capacity (PCAP) PRM. If firm resources are counted toward the PRM based on their unforced capacity, then the PRM that satisfies the reliability target is considered an unforced capacity (UCAP) PRM. Finally, if firm resources are counted toward the PRM based on their rated capacity, then the PRM that satisfies the reliability target is considered an installed capacity (ICAP) PRM. All PRM accounting conventions are valid and will result in the same level of resource adequacy if the PRM is calculated based on the reliability target. The only difference is how firm resources are counted toward the PRM. The PCAP PRM is lower than the UCAP PRM and ICAP PRM, but under the PCAP PRM accounting convention, firm resources' capacity contributions are also lower. This study utilizes the PCAP PRM accounting convention.[1]

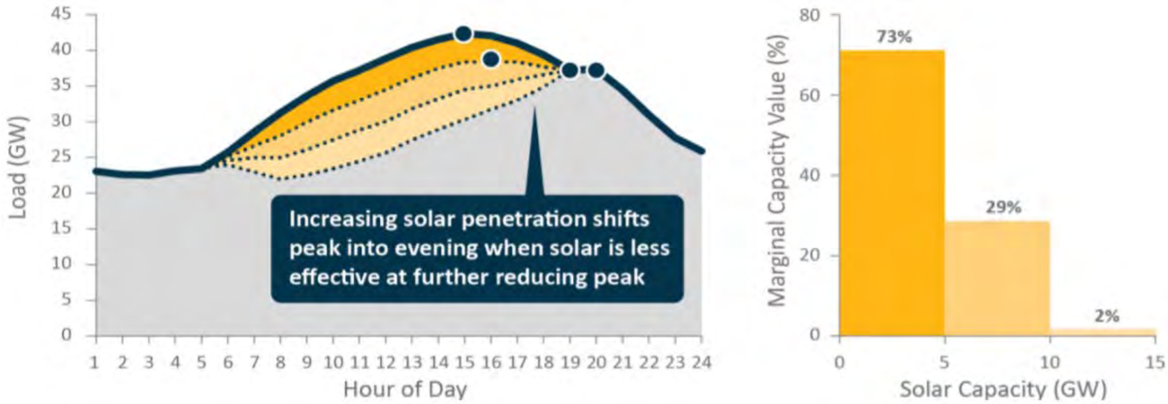
1.3.3 Effective Load Carrying Capability

The contribution of resources towards a utility's resource adequacy needs is less than their full operating capacity. For variable renewable resources like wind and solar, this occurs because their output is variable, and their capability to generate at the times needed for resource adequacy is typically less than their rated capacity. For energy storage, the "duration" – a measure of the amount of time a storage device can discharge at full capacity before its state of charge is exhausted – may limit its ability to produce power when needed. Demand response programs typically have similar limitations on the duration of calls, as well as on the number of calls. Even firm thermal generators, such as natural gas and nuclear power plants, have limitations due to forced outages that can occur. Evaluating the extent to which these resources can contribute to resource adequacy therefore requires a rigorous analytical framework that properly captures their limitations and performance characteristics.

This framework must account for two key dynamics that impact the capacity contributions of dispatch-limited resources (solar, wind, geothermal, energy storage, demand response). First, the capacity contributions of a specific resource type tend to diminish with increasing levels of penetration. Figure 1-2 illustrates this phenomenon by plotting the effect of increasing levels of solar PV production on the "net peak" demand – gross load less dispatch-limited resources. While the first increments of solar PV provide significant capacity value because of their coincidence with peak demand, at high penetrations, the net peak shifts into the early evening when the sun is setting or has already set, such that further additions provide little to no incremental capacity value to the system.

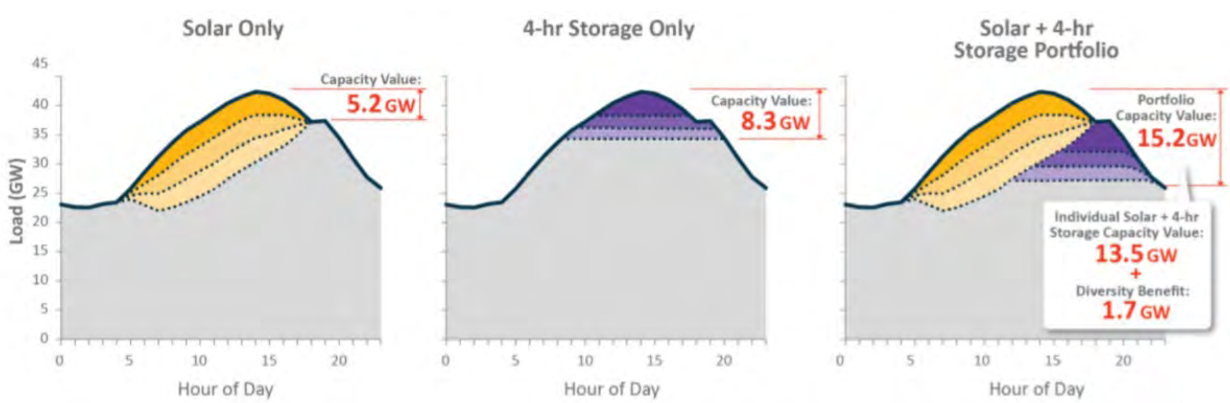
[1] While the study utilizes the PCAP PRM convention, it is straightforward to convert the resulting PCAP PRM to an ICAP PRM.

Figure 1-2. Illustrative Example of Solar PV Ability to Reduce Net Peak Load[2]



Second, the contribution of a resource towards system resource adequacy depends on the characteristics of the other resources in the portfolio; that is, resources have interactive effects with one another such that a portfolio of resources may provide a capacity contribution that is greater than (or smaller than) the sum of its parts. Figure 1-3 illustrates this phenomenon for a portfolio comprising solar PV and storage resources. In this example, the combined portfolio of solar PV and storage provide a larger reduction in the net peak demand of the system due to their synergistic interactive effects; the solar production during the day effectively narrows the breadth of the net peak, allowing more efficient use of the energy storage. The synergistic interactive effects are sometimes referred to as "diversity benefit" because the diverse characteristics results in a greater contribution to resource adequacy.

Figure 1-3. Illustration of Diversity Benefit from Adding Solar and Storage[2]



To account for these complex and interactive dynamics, this study relies on effective load carrying capability (ELCC) to quantify the contributions of various dispatch-limited resources towards El Paso Electric's PRM requirement. The ELCC method is increasingly becoming the industry standard, especially in systems with high levels of dispatch-limited resources. ELCC is defined as the quantity of "perfect" capacity that could be replaced or avoided by a non-firm resource while providing equivalent system

[2] This example is illustrative and does not reflect El Paso Electric data.

reliability. For example, an ELCC value of 50% would mean that the addition of 100 MW of a variable resource could displace the need for 50 MW of perfect capacity without an impact on reliability.

Accurately quantifying ELCC values requires the use of loss-of-load-probability (LOLP) models, which simulate the balance of available supply and demand across a broad range of weather conditions to ensure that the modeling appropriately captures the performance of resources during periods of system stress, including capturing the effects of any correlations (positive or negative) that might exist between dispatch-limited resource production and load.

1.4 Clean Energy Policy

Across the country, states and utilities are making increasingly ambitious commitments to reduce their greenhouse gas (GHG) emissions in a collective effort to avoid the worst impacts of climate change. These policies are reshaping the industry through power plant retirements, renewable and gas plant additions, and adoption of new technologies.

El Paso Electric serves customers in New Mexico and Texas, both of which have established clean energy requirements. The New Mexico requirements are more stringent, requiring an increasing share of retail sales to be supplied by renewable sources and requiring 100% of retail sales to be supplied by zero-carbon energy sources by 2045. The Texas requirements set a minimum renewable energy level, part of which is allocated to El Paso Electric (approximately 365 GWh per year). This section discusses the resource options available to meet clean energy requirements, the options for integrating these resources within a grid, and key considerations for developing optimal long-term resource portfolios.

1.4.1 Renewable and Zero-Carbon Resources

Clean energy policy is generally in the form of a Renewable Portfolio Standard (RPS) or a Clean Energy Standard (CES). An RPS requires utilities to generate a given percentage or amount of electricity from renewable energy resources. Eligible resources typically include solar, wind, geothermal, biomass, and some hydro facilities. A CES is similar to an RPS, but the eligible resources are often expanded to include any resource that has no carbon emissions. This could include resources such as nuclear, large hydro, and combustion power plants that use zero-carbon fuels.

Among the renewable and zero-carbon resources, solar and wind have accounted for most capacity additions in the U.S. in recent years. Their costs have declined significantly over the last decade, and incentives such as the investment tax credit (ITC) and production tax credit (PTC) have lowered their costs further. Many utilities have added solar and wind to their portfolios purely based on economics.

Other commercially available and widely deployed zero-carbon resources include geothermal, biomass, nuclear, and hydro resources. However, these resources have seen significantly less growth than solar and wind in recent years because of limited availability, permitting challenges, long lead times, and/or high costs. For example, the opportunities for new hydro facilities are limited due to availability of new sites that can be permitted and developed.

There are also emerging technologies that are not widely deployed today but could potentially help reach clean energy requirements in the future. One example is combustion turbines that burn hydrogen produced from renewable energy resources. While this technology is not widely deployed, there are several projects planned over the next several years. Other emerging zero-carbon technologies include advanced nuclear and advanced geothermal.

Solar and wind resources are different from many other zero-carbon resources in that their production is more variable. Solar facilities produce during daytime hours, and that production varies by season based on the position of the sun relative to the facilities. Moreover, the output drops when there is cloud cover. While the diurnal and seasonal factors are predictable, cloud cover is more difficult to predict and can vary more from day to day. Wind facilities can produce anytime, but their production depends on there being wind. Wind speeds are variable hour to hour and day to day, making wind generation variable. While there are these variations, there are also typical daily and seasonal generation trends. Wind generation tends to be higher during nighttime and during non-summer months.

Given the variable nature of solar and wind facilities, utilities and market operators must plan their system and operations to integrate these resources effectively.

1.4.2 Integration of Renewable Resources

The first step to integrating renewable resources is to ensure that their generation can be delivered to load centers via transmission. High-quality solar and wind resources may be remote from existing transmission infrastructure, or may require upgrades to existing transmission infrastructure to be deliverable. Transmission upgrades and/or new transmission lines are necessary to connect remote resources to load centers and improve the utilization of renewable resources.

The second step to integrating renewable resources is to adjust operations. Utilities and market operators commit and dispatch thermal resources differently to allow renewable resources to serve load. Renewable resources such as solar and wind have no fuel costs, so once they are built, they cost less to operate than power plants that do have fuel costs. Utilities dispatch thermal resources downward when renewables are generating and dispatch thermal resources upward when renewables are not generating. In addition, utilities may commit fewer thermal resources to be online during time periods when renewable generation is expected to be high.

There are limitations to altering thermal plant operations to integrate renewables. For one, thermal plants have operational limitations. There are limitations to how fast they can ramp upward or downward. In addition, there are limitations to how low their power outputs levels can be when online. Some power plants, such as nuclear power plants, cannot operate flexibly. Moreover, utilities and market operators may not turn all thermal plants off during a period to absorb more renewable energy because they need these resources to be online to provide operating reserves or to ramp up to satisfy load during periods when renewable output is lower. Overall, thermal resources that are more flexible – such as gas facilities (compared with coal facilities) or gas combustion turbines (compared with steam turbines) – can help integrate renewable resources more effectively.

There are other resources that can help integrate renewable energy into operations. Storage resources, such as batteries, can charge during time periods when renewable generation is abundant and discharge during time periods when renewable generation is lower. In addition, flexible end uses can shift energy demand from periods when renewable generation is lower to periods when renewable generation is higher. For example, an electric vehicle could delay charging until periods when renewable output is generally high rather than charging immediately when plugged in. Both storage and flexible end uses could increase flexibility on the system and help the system absorb more renewable energy.

Another tool for integrating renewable energy is to sell generation to others during periods when there is more renewable energy than can be integrated. The ability to do this is dependent on regional market conditions. For example, the real-time Western Energy Imbalance Market (Western EIM) facilities renewable energy integration by finding low-cost redispatch opportunities to serve real-time demand across its regional footprint. If one entity has excess renewable production, it can earn revenue by selling that generation to neighboring entities that can save money from ramping down more expensive generators. However, if neighbors are also adding a considerable amount of the same renewable resources, there may be limited opportunities to sell because all entities would have excess generation at the same time (e.g., solar during mid-day hours). In general, markets with a larger geographical footprint offer more load and resource diversity, as well as more opportunities for renewable integration.

Despite the integration strategies discussed, there can still be times when there is more renewable generation than can be absorbed. Curtailing renewable generation is the last resort to keep the system load and generation in balance. The need for curtailment can vary by season. For example, during the spring months, solar radiation is high, yet electricity demand is low due to more mild temperatures. If the system has a lot of solar resources, then there could be oversupply conditions in spring, necessitating renewable curtailment. In the summer, however, there is a lot of solar radiation, but there is also a lot of demand due to increased cooling demands, reducing the need for curtailment. Many systems with high renewable energy penetration levels experience some amount of curtailment during the year. Trying to avoid all curtailment may artificially limit renewable additions or could result in higher-cost solutions.

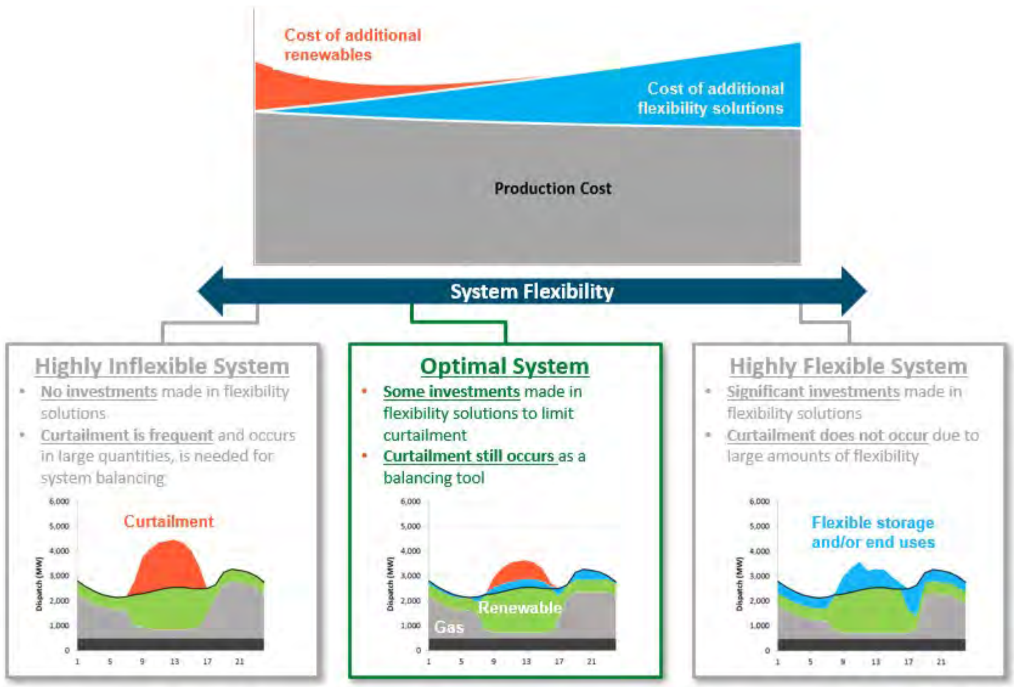
1.4.3 Renewable Integration in Optimal Long-Term Resource Portfolios

Developing an optimal long-term resource portfolio involves minimizing system costs while ensuring the system satisfies reliability and clean energy requirements. Such an optimization considers the costs and characteristics of different resources options, as well as the magnitude and timing of energy demand. Among these factors, the optimization considers the options and costs for integrating additional renewable and zero-carbon generation. Given all these factors, the optimization selects optimal resource additions. The penetration of renewable and zero-carbon energy in this optimal portfolio must satisfy clean energy policy requirements.

The optimal portfolio strikes a balance between different solutions for integrating renewable resources. At higher renewable penetration levels, two of the key strategies for further increasing penetration are (1) to continue adding more renewable resources, even if some of the generation will be curtailed, and (2) to add flexible storage or leverage flexible end uses to increase utilization of renewable resources. The optimal portfolio strikes a balance between these strategies.

Figure 1-4 illustrates this balance by showing how system costs change by relying more on one strategy or the other. The far left side represents a system with no investment in flexibility solutions. In this case, significant renewable additions are needed, resulting in significant and frequent curtailment to balance the system. This curtailment decreases the value of the additional renewables, resulting in increased system costs. Moving to the right reflects an increases reliance in flexibility solutions to integrate renewables. The far right slide represents a system that has a lot of flexibility and does not experience any curtailment. While fewer renewable additions are needed due to the decrease in curtailment, the cost of achieving this level of flexibility is very high. Neither end of the spectrum is the most cost-effective solution. The optimal system lies somewhere in between where there is a balance between curtailment and flexibility solutions.

Figure 1-4. Trade-Offs Between Curtailment and Flexibility Solutions[3]



1.4.4 Relationship Between Renewable Penetration and Cost

The optimal long-term resource portfolio corresponds to a given penetration of renewable and zero-carbon resources. This optimal penetration balances the costs and benefits of these resources, considering different solutions for integration. Given observed reductions in renewable and storage costs and the expectation for these trends to continue, the optimal penetration levels for renewable resources have never been higher in the industry, and these resources provide significant cost-saving opportunities. Nevertheless, increasing the penetration of renewable resources beyond the least-cost optimal level would increase costs to the system.

There are a few factors that contribute to the increase in system costs. First, renewable resources have declining marginal energy value. Energy value is the value from displacing generation or imports from

3 The examples here are illustrative and do not represent the El Paso Electric system.

other resources. This value declines with successive additions of renewable resources because curtailment increases as penetration increases. Storage or other flexibility solutions can help reduce curtailment by shifting the generation to other time periods, but the energy value continues to decline because it is not economic to eliminate all curtailment on all days. Storage and other flexibility solutions add costs that must be balanced with accepting more curtailment.

Second, as discussed in Section 1.3.3, the capacity value of renewable resources declines at higher penetration levels. Capacity value is the value from displacing resources that would otherwise be needed to ensure reliability. Because the incremental ELCC of renewable resources declines at higher penetration levels, successive renewable additions contribute less and less to satisfying reliability needs. Storage and other flexibility solutions, such as demand response, can help contribute to reliability needs, but they too experience declining marginal capacity value.

In summary, as renewable penetration increases beyond the cost-optimal level, system costs increase because the incremental cost of renewables exceeds the incremental value of these resources. Because renewables have declining marginal energy and capacity value, system costs increase more at higher penetration levels. This report explores these dynamics for El Paso Electric's system, both under existing state policy and under more aggressive decarbonization targets.

1.5 Organization of Report

The remainder of the report is organized as follows:

- Section 2 describes the methodology for the analyses;
- Section 3 details the load and resources assumptions that are utilized;
- Section 4 provides the results of the PRM analysis;
- Section 5 provides the results of the ELCC analysis;
- Section 6 provides the results of the portfolio analysis; and
- Section 7 provides the results of the sensitivity analysis.

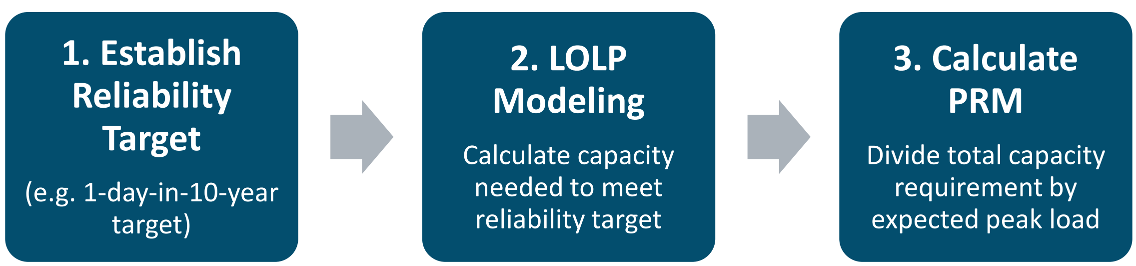
2 Methodology

This section describes the methodology for the Planning Reserve Margin, Effective Load Carrying Capability, and Resource Portfolio Optimization analyses. Each subsection describes the methodology, inputs, and outputs for the analyses.

2.1 Planning Reserve Margin

E3 calculated the planning reserve margin (PRM) for El Paso Electric in two years: 2025 and 2030. The planning margin ensures that, if satisfied, the El Paso Electric system can ensure reliability, subject to a reliability target. Figure 2-1 shows the steps for calculating the PRM, and the following sections describe each step in detail.

Figure 2-1. PRM Calculation Steps



2.1.1 Reliability Target

El Paso Electric has directed E3 to utilize a 2-day-in-10-year reliability target for 2025 in the near term and to utilize a 1-day-in-10-year reliability target for 2030 and beyond. The 2-day-in-10-year reliability target means that, on average, there can only be two days with outage events every ten years. This corresponds to a 0.2 loss-of-load expectation (LOLE). The 1-day-in-10-year reliability target means that, on average, there can only be on day with outage events every ten years and corresponds to 0.1 LOLE. Transitioning from a target of 0.2 LOLE in 2025 to a target of 0.1 LOLE in 2030 allows for a gradual shift toward the more stringent target.

While there is no universal reliability target in use throughout the industry, the most common target utilized by utilities and program administrators in North America is the 1-day-in-10-year standard, or 0.1 LOLE. Table 2-1 shows a survey of reliability targets used throughout the industry.

Table 2-1. Survey of Reliability Targets Used by Utilities and Grid Operators

Utility	Reliability Metric	Reliability Target
Arizona Public Service	LOLE	0.1 days/yr
Avista	LOLP[4]	5% per year
Duke Energy Utilities[5]	LOLE	0.1 days/yr
Idaho Power Company	LOLE	0.1 days/yr
JEA	LOLE	0.1 days/yr
Louisville Gas & Electric and Kentucky Utilities	LOLE	0.1 days/yr
NorthWestern Energy	LOLE	0.1 days/yr
Nova Scotia Power, Inc.	LOLE	0.1 days/yr
NV Energy	LOLE	0.1 days/yr
PacifiCorp	LOLE	0.1 days/yr
Portland General Electric	LOLH[6]	2.4 hours/yr
Public Service Company of New Mexico[7]	LOLE	0.2 days/yr
Public Service Company of Colorado	LOLE	0.1 days/yr
Puget Sound Energy	LOLP[4]	5% per year
Southern Company Utilities[8]	LOLE	0.1 days/yr
ISO/RTO/Grid Operator	**Reliability Metric**	**Reliability Target**
Alberta Electric System Operator	EUE[9]	800 MWh/yr (0.0014%)
Electric Reliability Council of Texas[10]	N/A	N/A
Florida Reliability Coordinating Council	LOLE	0.1 days/yr
ISO New England[11]	LOLE	0.1 days/yr
Midcontinent ISO	LOLE	0.1 days/yr
New York ISO[11]	LOLE	0.1 days/yr
PJM[11]	LOLE	0.1 days/yr
Southwest Power Pool	LOLE	0.1 days/yr

2.1.2 Loss-of-Load Probability Modeling

E3 utilized RECAP, a proprietary loss-of-load probability (LOLP) model, to determine the PRM for the El Paso Electric system. RECAP simulates the availability of electric supply to meet demand across a broad range of conditions, accounting for factors such as weather-driven variability of electric demand, forced outages of power plants, the natural variability of resources such as wind and solar, and operating

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[4] Loss-of-load probability (LOLP) corresponds to the probability that system needs exceed available generation over the course of a year.

[5] These utilities include Duke Energy Carolinas, Duke Energy Progress, and Duke Energy Florida. Duke Energy Indiana operates within the Midcontinent ISO (MISO) market, whin plans to a 0.1 LOLE standard.

[6] Loss-of-load hours (LOLH) corresponds to the expected number of hours per year that system needs exceed available generation.

[7] PNM recently indicated its future intention to shift towards a standard of 0.1 days per year in a recent filing.

[8] These utilities include Alabama Power, Georgia Power, and Mississippi Power. The 0.1 LOLE standard is a minimum for determining the PRM.

[9] Expected unserved energy (EUE) corresponds to the expected total quantity of unserved energy (MWh) over a year due to system needs exceeding available generation.

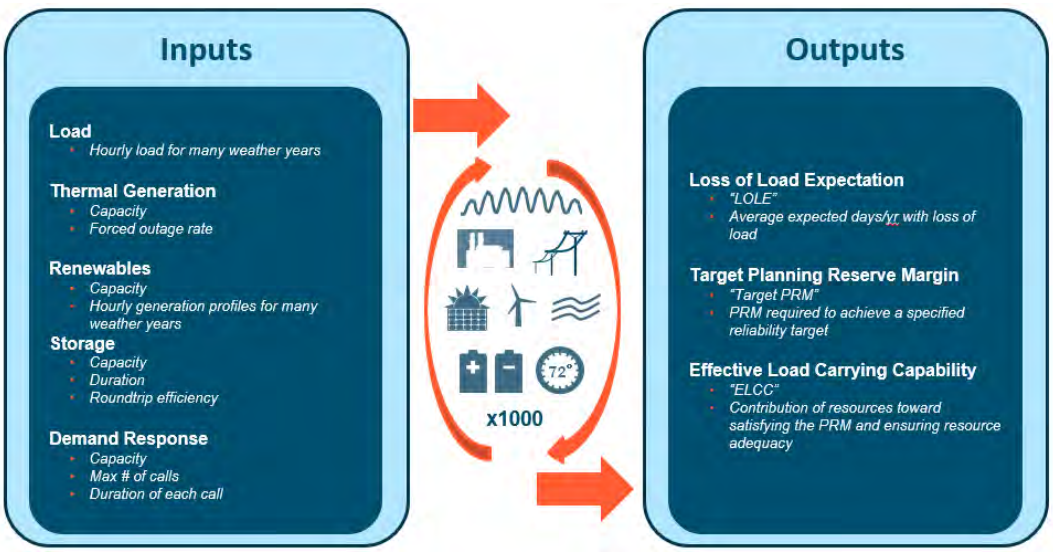
[10] ERCOT has eschewed a formal standard for resource adequacy and instead relies upon the energy market to provide a competitive market pricing signal for resource adequacy

[11] In jurisdictions with centralized capacity markets, the reliability standard is used to calibrate a PRM target, which is subsequently used as the basis for the creation of a demand curve for capacity.

constraints for resources like storage and demand response. These simulations determine the likelihood and magnitude of loss of load – energy demand that cannot be served – and provide the basis for calculating the PRM.

RECAP simulates hundreds of "years" of potential conditions using stochastic techniques to appropriately capture the risk of tail events (e.g., higher load and lower renewable output than expected).[12] RECAP simulates the system[13] each hour of a year and repeats this process thousands of times with different system conditions (see Figure 2-2). This ensures that RECAP captures a wide distribution of potential outcomes, including tail events. Correlations are enforced within the model to ensure linkage among load, weather, and renewable generation conditions, based on historical observations.

Figure 2-2. RECAP Model Overview



For each simulation year, RECAP conducts a Monte-Carlo time-sequential simulation of loads, renewable output, and resource availability (see Figure 2-3). Energy storage charges from renewable generation during daytime hours and discharges to meet any residual load. RECAP tracks the state of charge of energy storage resources to ensure their operations respect physical limitations. Demand response resources serve as a last resort and are constrained by limitations on the number and durations of calls. If there is a period during which the supply of resources is inadequate to meet the load requirement, there is a loss of load event.

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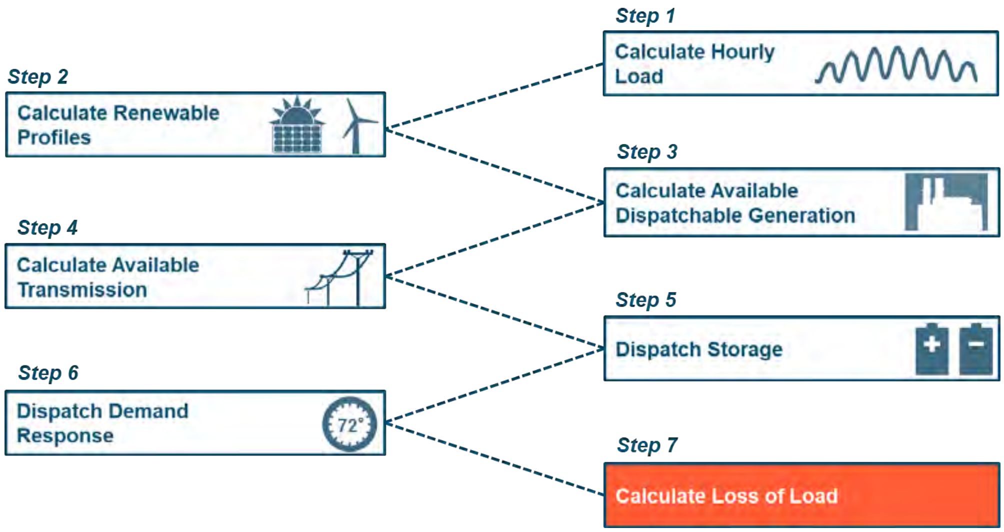
[12] In this approach, each "year" represents a different realization of conditions on the El Paso Electric system over the course of a year. Factors that will vary from one "year" to the next include underlying weather patterns – and by extension, load and renewable profiles – and the occurrence of power plant outages.

[13] RECAP does not simulate the economic dispatch or operations of the electric system but focuses on whether the total available resources is sufficient to meet load. In this respect, RECAP does not provide an economic comparison among different resources but can be used to assess their contributions to resource adequacy.

Figure 2-3. RECAP Simulation Steps



RECAP determines the frequency, duration, and magnitude of loss of load events across all simulation years. RECAP then calculates the loss of load expectation (LOLE), which is the expected number of days per year on which resources would be insufficient to meet loads.

2.1.3 Planning Reserve Margin Calculation

The results of RECAP can also be translated into a simpler and more widely used PRM requirement, a target for system reliability expressed as a percentage requirement above expected peak demand. PRM requirements are used by many utilities and independent system operators (ISOs) in their administration of resource adequacy requirements. Thus, RECAP also expresses its outputs in terms of the PRM:

+ The achieved PRM of a system is calculated based on the summation of capacity provided by all resources; in this study, all resources are rated based on their effective load carrying capability (ELCC), as further described in Section 2.2. This total amount of capacity is divided by the expected peak to determine the PRM of the system.
+ The PRM requirement of a system (i.e., the PRM needed to achieve the reliability target) is calculated by adding or removing generic perfect capacity resources[14] to the system as needed to achieve the desired reliability target. The PRM for this adjusted system then represents the reserve margin needed to meet the reliability target.

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[14] "Perfect capacity" describes a hypothetical resource that is available at full capacity all hours of the year. While no resource is truly perfect, this hypothetical resource provides a useful benchmark against which to measure the capacity value of real-world resources.

2.1.4 Model Inputs

Table 2-2 lists the inputs that are utilized in the PRM study and where the inputs are described in more detail in this report.

Table 2-2. Inputs for the PRM Study

Input Category	Input	Section with Additional Detail
Load	Load forecast (2021-2040)	Section 3.1
	Historical hourly load (2010-2019)	Section 4.1
	Operating reserve requirements	Section 4.2
Weather	Historical temperature data (1950-2019)	Section 4.1

2.1.5 Model Outputs

The primary outputs from the PRM study are the following:

+ PRM requirement in 2025 that, if met, satisfies the reliability target of 0.2 LOLE
+ PRM requirement in 2030 that, if met, satisfies the reliability target of 0.1 LOLE

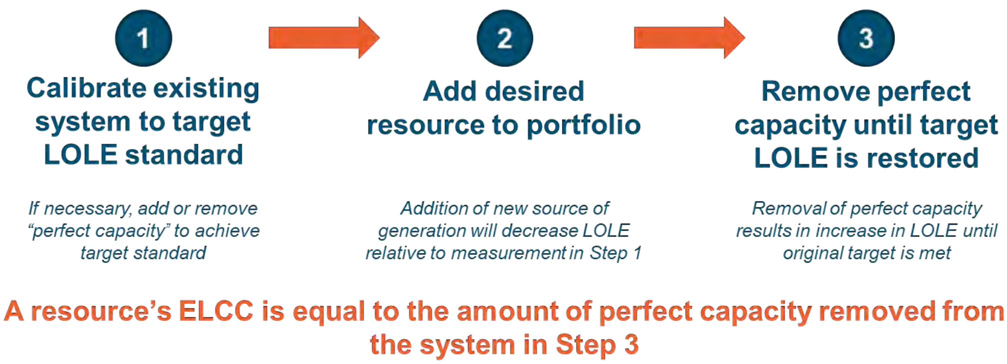
2.2 Effective Load Carrying Capability

E3 evaluated the effective load carrying capability (ELCC) for several resource types. The ELCC determines how much a particular resource or set of resources can contribute to the PRM for ensuring resource adequacy. The ELCC for a particular resource (or set of resources) is calculated through a three-part process (see Figure 2-4):

1. The system is simulated without the specified resource in RECAP to determine the LOLE of the system. If the resulting LOLE does not match the specified reliability target, the system is "adjusted" to meet the target reliability standard (e.g., 0.1 days/yr). This adjustment occurs through the addition (or removal) of a perfect capacity resource[15] to achieve the desired reliability standard.
2. The specified resource is added to the system and the LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available capacity has increased.
3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to a percentage value by dividing by the installed capacity of the specified resource.

[15] A perfect capacity resource is a resource that can generate on demand and has no forced outage rate. In this study, it is used as a placeholder and is used to calculate the ELCC for dispatch-limited resources.

Figure 2-4. Iterative Approach to Determining Effective Load Carrying Capability



This methodology ensures that the ELCC of a resource corresponds to its contribution towards resource adequacy. By simulating the EPE system across a wide range of potential system conditions, RECAP captures the limitations of dispatch-limited resources and quantifies their contribution towards resource adequacy by measuring their substitutability for perfect capacity.

The following sections describe the methodology undertaken for different resources, as well as the model inputs and outputs.

2.2.1 Dispatch-Limited Resources

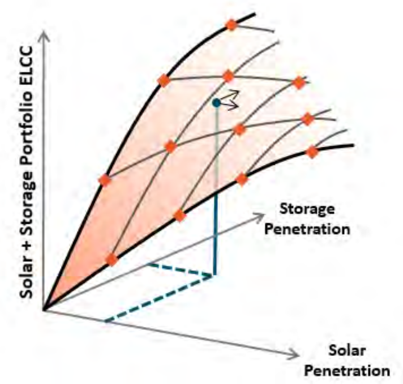
As discussed in Section 1.3.3, the ELCC of dispatch-limited resources depends on the penetration level of the resource within the portfolio. With each addition of a particular type of resource, the total ELCC in MW (or capacity contribution) increases, but the incremental ELCC from each successive addition decreases. As a result, each resource has a declining marginal ELCC curve as penetration increases. To account for this effect, E3 calculated the ELCC for multiple tranches of each dispatch-limited resource – solar PV, storage, wind, geothermal, and demand response. E3 selected tranches such that the ELCC results span a wide range of penetration levels for each resource.

In addition to quantifying each resource's own contribution to reliability, E3 also considered the synergistic interactive effects or diversity value when some resources are added to the system together. Solar PV and storage can have a meaningful diversity benefit at higher penetration levels (see Figure 1-3). Developing ELCC curves for the two resources independently would underestimate the combined ELCCs.

2.2.2 Surface for Solar and Storage

To account for the diversity benefit of solar and storage resources, E3 calculated an ELCC surface for solar and storage. Figure 2-5 illustrates the ELCC surface for solar and storage conceptually, where the x-axis and y-axis correspond to solar and storage capacity and the z-axis corresponds to the total ELCC in MW. E3 calculated the ELCC for various penetration levels of solar PV and storage capacity to trace out the surface. Because the two resources are being added together to the system, the ELCC captures any diversity benefits.

Figure 2-5. Illustrative Solar and Storage Surface



2.2.3 Thermal Resources

As discussed in Section 1.3.2, this study uses a PCAP as the PRM accounting convention. As a result, thermal resources are counted toward the PRM based on their ELCC. Because thermal resources have forced outages, the ELCC is less than 100%. To quantify the ELCC of thermal resources, E3 followed the same three-step process described above.

2.2.4 Model Inputs

Table 2-3 lists the inputs that are utilized in the ELCC study and where the inputs are described in more detail in this report.

Table 2-3. Inputs for the ELCC Study

Category	Input	Location in Report
Load	Load forecast (2030)	Section 3.1
	Historical hourly load (2010-2019)	Section 4.1
	Operating reserve requirements	Section 4.2
Weather	Historical temperature data (1950-2019)	Section 4.1
Thermal Resources	Net dependable capacity	Sections 3.2 & 3.3
	Forced outage rate	Section 5.2
Renewable Resources	Nameplate capacity	Sections 3.2 & 3.3
	Historical hourly solar insolation and wind speed data for locations	Section 3.4
	Hourly generation profile for geothermal resources	Section 3.4.3
Energy Storage Resources	Nameplate capacity (charge & discharge)	Section 3.3
	Roundtrip efficiency	Section 3.5.1
	Duration (hours)	Section 3.5.1
Demand Response	Maximum capacity	Section 3.5.3
	Maximum # of calls per week/month/year	Section 3.5.3
	Maximum duration of each call	Section 3.5.3

2.2.5 Model Outputs

The ELCC study quantifies the ELCC for the following resources:

- Solar PV
- Storage
- Geothermal
- Wind
- Demand Response
- Thermal Resources

The ELCC for all of these resources, except for thermal resources, depends on the penetration level of the resource (i.e., how much capacity there is relative to load). E3 quantified the ELCC for resources in 2030, but the load conditions are different in other years. At higher load levels in future years, for a given capacity level of a resource, the ELCC of that resource would be slightly higher because its penetration is slightly lower relative to 2030 conditions. E3 accounts for this effect by adjusting the ELCC of resources based on changes in load relative to 2030 conditions.

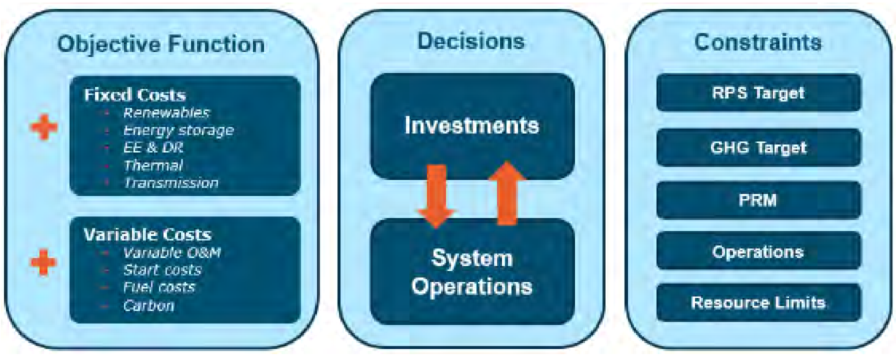
2.3 Resource Portfolio Optimization

2.3.1 Resource Portfolio Optimization

E3 performed resource portfolio optimization in this study using its RESOLVE model. RESOLVE is an electricity system capacity expansion model that identifies economically optimal long-term generation and transmission investments subject to reliability, technical, and policy constraints. RESOLVE considers both the fixed and operational costs of different portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments vs. renewable curtailment/overbuild. The model uses weather-matched load and renewable data and simulates interconnection-wide operations over a representative set of sample days in each year. The model captures the dynamic contribution of renewable and energy storage resources to the system that vary as a function of their penetration, specifically in terms of capacity requirements toward the planning reserve margin.

Figure 2-6 provides an overview of the RESOLVE model including the objective function, key model decisions and the constraints imposed.

Figure 2-6. Overview of the RESOLVE Model



2.3.2 Objective Function

The objective function minimizes net present value (NPV) of electricity system costs over the planning horizon,[16] which is the sum of fixed costs and variable costs, subject to various constraints. Fixed costs include both the investment costs of new generation and storage resources, associated transmission costs required with the generation resources, as well as fixed operating and maintenance costs of new and existing resources. Variable costs comprise variable operating and maintenance costs and fuel costs, including start costs.

2.3.3 Operations Module

For the representative set of sample days each year, hourly operations are simulated through economic dispatch of existing and new resources in order to meet load. The dispatch logic depends on the type of resource. Solar and wind resources have fixed generation profiles based on the resource location and have the ability to be curtailed when total generation exceeds load. Most thermal resources like natural gas turbines are operated flexibly while meeting operating constraints such as minimum generation level, maximum ramp rate, minimum up and down time. Palo Verde Nuclear Generating Station is modeled as a baseload resource, generating power at its nameplate capacity during all hours except during planned

[16] This study has a planning horizon of 2021-2045. This twenty-five-year period captures the 2045 requirement for zero-carbon energy in the New Mexico Renewable Energy Act (REA).

outages for refueling. Energy storage resources like batteries increase load when charging and can serve load when discharging, maintaining charge parity over each sample day.

2.3.4 Constraints

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

+ **Planning reserve margin (PRM)**: When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet the annual system peak load plus an additional specified amount of PRM requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours.

+ **Renewables Portfolio Standard (RPS) requirements:** RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year. RESOLVE has the ability to flag which resources can contribute to an RPS requirement, which enables policies like a Clean Energy Standard (CES), where nuclear resources are eligible to contribute to the target, to be modeled. Note that the RPS or CES requirement does not apply to all the cases modeled.

+ **Greenhouse gas emissions cap**: RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio. As the name suggests, the emission cap type policy requires that annual emissions generated in the entire system be less than or equal to the designed maximum emissions cap. In its most extreme form, a greenhouse cap at zero emissions would preclude all power-sector emissions, though some “zero-emission” fuels such as hydrogen still qualify. Note that the greenhouse gas cap does not apply to all the cases modeled.

2.3.5 Day Sampling

RESOLVE makes both investment and operational decisions over a long period of time, which is a computationally intensive process. To ensure that the model finds the optimal solution in a reasonable amount of time, E3 models a subset of days rather than modeling every day across the modeling horizon. E3 utilizes a sampling algorithm to select a combination of days that, together, have characteristics that are representative of conditions on the electricity system over the course of multiple years. These sample days are a small subset of the days that are analyzed in RECAP.

This sampling algorithm optimizes the days that are included in the modeling such that, when taken in aggregate and weighted appropriately, provide a good representation of the breadth of load, wind, and solar conditions observed in the historical record. The process for selecting the set of representative days follows three steps:

1. **Create extensive database of hourly load and renewable profiles:** E3 creates an extensive library of load, wind, and solar profiles to reflect a broad distribution of weather conditions. In this study, EPE provided load and solar data, and E3 gathered additional solar data and wind data from National Renewable Energy Laboratory (NREL) databases. Together, this data informs the relationships and correlations between load, wind generation, and solar generation.
2. **Select key variables as indicators of system conditions:** E3 identifies variables to characterize whether the sample days accurately reflect system dynamics across a wide range of conditions. In this study, the variables included: (1) the distribution of hourly load, (2) the distribution of hourly wind production, (3) the distribution of hourly solar production, and (4) the distribution of hourly net load for a given amount of solar and wind on the system in 2030. If the system conditions for the sample days are representative of conditions over a longer period, then these distributions will be similar for both the sample days and the longer period. E3 measures the fit of the sample day distributions by calculating the difference from the longer period distributions. This is known as the error.
3. **Select representative days using optimization to ensure fit:** E3 performs an optimization to select a set of days from the candidate pool of days established in step (1) while minimizing the total error for the variables established in step (2). In addition to identifying sample days, the optimization identifies associated weights to apply to each sample day such that the sample days, in aggregate, given their weights, are representative of system conditions over a longer period. In this study, E3 selected at least two days for each month, with one representing a weekday and the other representing a weekend day. This ensures that the sample days cover different seasons and day types. In addition, E3 selected six additional days, with at least one representing peak day conditions, for a total of thirty sample days.

2.3.6 Cases

The complete list of cases modeled in RESOLVE is summarized in Table 2-4.

Table 2-4. List of Cases

Case	Description
Least-Cost	Least-cost optimization used as base case for all sensitivities
Least-Cost Case + REA Resources[17]	Additional resources added to Least-Cost Case for New Mexico REA
Separate System Planning	New Mexico system planned separately for purposes of satisfying REA
80% Clean by 2035	80% zero-carbon energy
20% GHG Reduction by 2040	20% reduction in greenhouse gas emissions
40% GHG Reduction by 2040	40% reduction in greenhouse gas emissions
60% GHG Reduction by 2040	60% reduction in greenhouse gas emissions
80% GHG Reduction by 2040	80% reduction in greenhouse gas emissions
90% GHG Reduction by 2040	90% reduction in greenhouse gas emissions
100% GHG Reduction by 2040	100% reduction in greenhouse gas emissions
100% GHG Reduction by 2040 (w/ H_2)	100% reduction in greenhouse gas emissions with hydrogen
Low Load Growth	3-4% higher native system load forecast
High Load Growth	3-4% lower native system load forecast
High Distributed Generation (DG)	High DG forecast
High Demand-Side Management (DSM)	More smart thermostats, doubling of energy efficiency
No New Gas	No new gas after Newman 6
No Lifetime Extensions	All plants retire as scheduled
High Gas Price	Gas prices 15% higher
Low Carbon Price	$8 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
Mid Carbon Price	$20 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
High Carbon Price	$40 per metric ton of carbon dioxide in 2010, rising at 2.5% per year
Low Technology Cost	Lower technology cost declines for renewable and storage resources

2.3.7 Model Inputs

Table 2-5 lists the inputs that are utilized in the resource portfolio optimization study and where the inputs are described in more detail in this report.

[17] The Least-Cost case has enough renewable energy to satisfy the renewable energy requirements for customers in the Texas jurisdiction. As a result, this case does not need to add additional resources for the purpose of satisfying Texas renewable energy requirements.

Table 2-5. Inputs for the Resource Portfolio Optimization Study

Input	Location in Report
Load	Section 3.1
Existing Resources	Section 3.2
Planned Resources	Section 3.3
Candidate Resources	Sections 3.4 and 3.5
Transmission	Section 3.6
Fuel Prices	Section 3.7
Planning Reserve Margin	Section 4.3
Effective Load Carrying Capability	Section 5
Candidate Resource Costs	Section 8
Market Prices	Appendix B: Price Assumptions

2.3.8 Model Outputs

RESOLVE produces many results, from technology level unit commitment decisions to total carbon emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

+ **Total system cost ($/yr):** RESOLVE reports the total annual system costs in the study footprint to provide service to its customers. This study focuses on the relative differences in system costs among cases, generally measuring changes in the relative to a reference case. The cost impacts for each case comprise changes in fixed costs (capital and fixed O&M costs for new generation resources, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs and fuel costs).

+ **Greenhouse gas emissions (MMT CO_2):** This result summarizes the total annual carbon emission in the system. By comparing the carbon emissions and total resource costs between different cases, we can conclude the relative effectiveness of the strategic measure in enabling carbon reductions.

+ **Resource additions and retirements for each period (MW):** The cumulative additions and retirements by resource type show the optimal strategy to meet future load given any emissions constraints.

+ **Annual generation by resource type (GWh):** Energy balance shows the annual system load and energy produced by each resource type in each modeled year. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of resources are dispatched more? How do the dispatch behaviors change over the years?

+ **Renewable curtailment (GWh):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—

based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.

+ **Market purchases (MW):** RESOLVE estimates hourly market purchases from WECC via Path 47 intertie that are found to be economic in meeting El Paso Electric's load. Projected wholesale market prices at the Palo Verde hub in WECC are specified exogenously for the snapshot years based on a broader regional analysis of the future western grid using production simulation software.

+ **Average and marginal greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a reference case) and the incremental cost (relative to that same case).

3 Loads and Resources

This section describes the characteristics of the El Paso Electric system. These characteristics and any associated assumptions serve as the basis for the study results. Loads comprise the sources of energy demand that must be satisfied in the future. Resources encompass various generating resources – existing and new – that can be operated to satisfy energy demand and other system planning requirements. Section 3.1 describes loads. Sections 3.2-3.5 describe resources, including existing, planned, and candidate. Section 3.6 describes transmission, and Section 3.7 describes fuel prices.

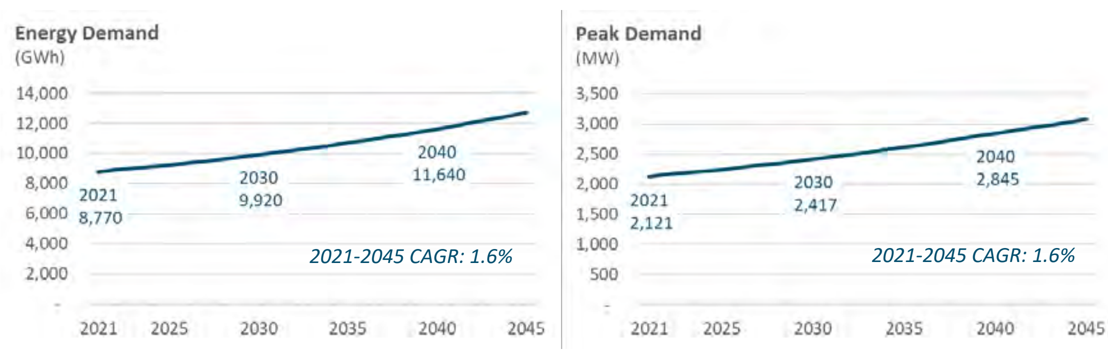
3.1 Loads

This section provides an overview of the load forecast and load profile used in this study. This forecast includes a forecast for existing end uses, described in Section 3.1.1, and a forecast for light duty electric vehicles, described in Section 3.1.2.

3.1.1 Existing End Uses Energy Demand

Figure 3-1 shows the El Paso Electric forecast for annual energy demand and peak demand, excluding electric vehicle loads, which are described in Section 3.1.2. El Paso Electric's load forecast goes through 2040 and is described in more detail in El Paso Electric's IRP. E3 trended the load forecast for an additional five years to extend it through 2045.

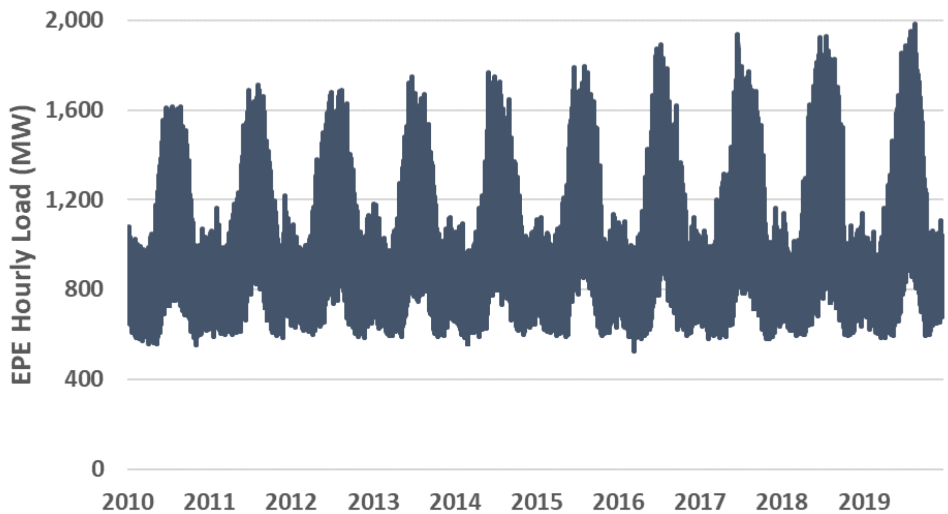
Figure 3-1. El Paso Electric Load Forecast[18]



[18] These load forecast charts correspond to native system load, less incremental energy efficiency. In this study, incremental distributed generation is treated as a supply-side resource and thus is not included in these charts.

To create hourly profiles for load that reflect an extended record of system conditions, E3 first gathered historical hourly load data from El Paso Electric for the years 2010-2019 (see Figure 3-2).

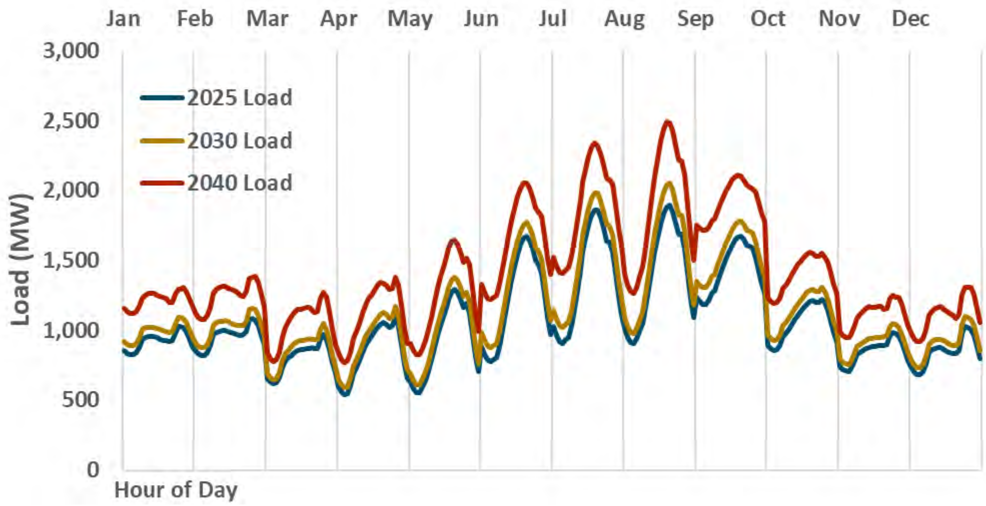
Figure 3-2. Historical Hourly Load of El Paso Electric from 2010 to 2019



E3 combined this historical system load data with weather data for the region going back to 1950 to develop hourly system loads for the period 1950-2019 under today's economic conditions. E3 utilized a neural network regression model to perform this analysis. E3 simulated hourly system load over seventy years of weather data to develop a collection of load shapes that reflect the variability in weather from year to year. E3 utilized all these load shapes when performing the loss-of-load probability modeling in RECAP, as described in Section 2.1.2. This ensures that RECAP considers a wide range of system conditions when assessing reliability needs. E3 utilized the load shapes for a subset of sample days to perform capacity expansion modeling in RESOLVE, as described in Section 2.3.5.

For the analysis period (2021-2045), E3 scaled the simulated load profiles to match El Paso Electric's monthly peak and energy demand forecasts. Figure 3-3 shows the average daily load profile by month in 2021, 2030, and 2040. Energy demand is significantly higher during summer months when building cooling demand is high.

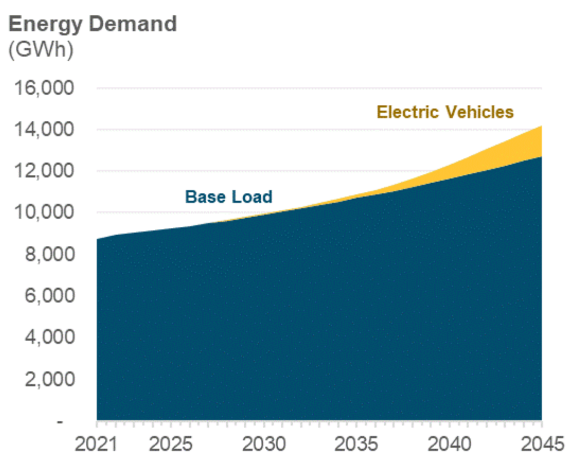
Figure 3-3. Average Daily Load by Month in 2021, 2030, and 2040



3.1.2 Electric Vehicle Energy Demand

Figure 3-4 shows the El Paso Electric forecast for annual energy demand for light duty electric vehicles. El Paso Electric's load forecast goes through 2040 and is described in more detail in El Paso Electric's IRP. E3 trended the load forecast for an additional five years to extend it through 2045.

Figure 3-4. El Paso Electric Energy Forecast Including Electric Vehicles[19]

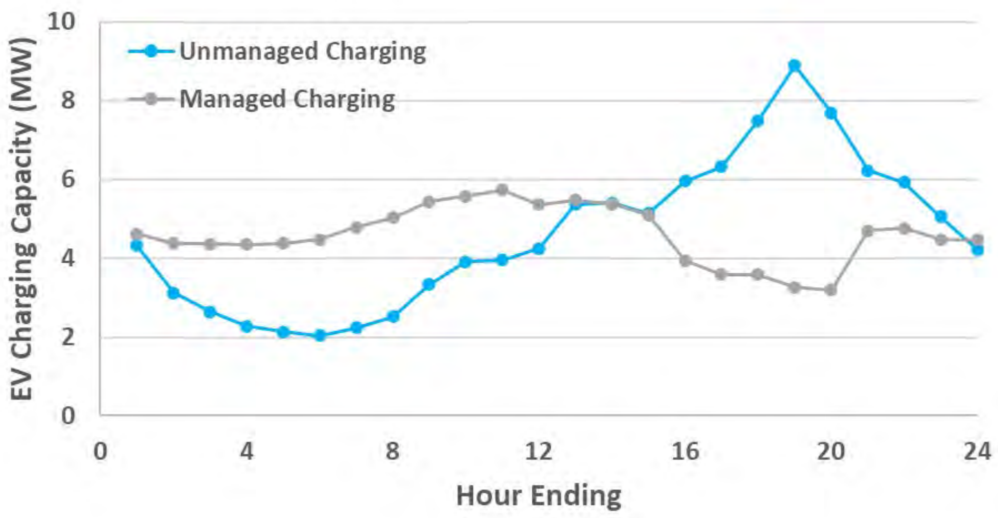


E3 developed a managed charging profile for electric vehicles based on driving data from the National Highway Traffic Safety Administration (NHTSA) and an assumption that time-of-use pricing or other programs would be in place to incentivize most customers to shift electric vehicle charging away from

[19] These load forecast charts correspond to native system load, less incremental energy efficiency. In this study, incremental distributed generation is treated as a supply-side resource and thus is not included in these charts.

peak load hours. Figure 3-5 shows the managed charging profile compared with an unmanaged charging profile for a summer weekday. The unmanaged charging profile assumes that drivers are not sensitive to the price signal or rate schedule and charge their vehicles whenever more charge is needed. The managed charging profile has a much flatter load profile and significantly reduces the impact of electric vehicles on peak demand hours in the late afternoon and early evening.

Figure 3-5. EV Charging Shape – Summer Weekday in 2030



3.2 Existing Resources

3.2.1 Existing Thermal Resources

Table 3-1 lists El Paso Electric's existing thermal generating resources. El Paso Electric currently has 1,422 MW of natural gas-fired generating capacity and 622 MW of nuclear generating capacity in its resource portfolio.

Table 3-1. Existing Thermal Resources

Resource	Jurisdiction	Fuel	Type	Summer Net Capacity (MW)	COD Year	Planned Retirement Year[20]	Age at Retirement
Rio Grande 6	System	Gas	ST	45	1957	Inactive Reserve[21]	63
Rio Grande 7	System	Gas	ST	46	1958	2022	64
Rio Grande 8	System	Gas	ST	144	1972	2033	61
Rio Grande 9	System	Gas	CT	88	2013	2058	45
Newman 1	System	Gas	ST	73	1960	2022	62
Newman 2	System	Gas	ST	73	1963	2022	59
Newman 3	System	Gas	ST	90	1966	2026	60
Newman 4	System	Gas	2x1 CC	227	1975	2026	51
Newman 5	System	Gas	2x1 CC	266	2009	2061	52
Copper	System	Gas	CT	63	1980	2030	50
Montana 1	System	Gas	CT	88	2015	2060	45
Montana 2	System	Gas	CT	88	2015	2060	45
Montana 3	System	Gas	CT	88	2016	2061	45
Montana 4	System	Gas	CT	88	2016	2061	45
Palo Verde 1	System	Nuclear	ST	207	1986	2045	59
Palo Verde 2	System	Nuclear	ST	208	1986	2046	60
Palo Verde 3	TX[22]	Nuclear	ST	207	1988	2047	59

Five generators are scheduled to retire prior to 2030, including Newman units 1-4 and Rio Grande unit 7. Together, the generating capacity at these units amounts to 509 MW, which is about 25% of today's total thermal generating capacity. For these units, E3 modeled the potential to extend their lifetimes by five years in all cases except for one ("No Lifetime Extensions"). There are incremental capital and operations and maintenance (O&M) costs to keep these units online for additional years. These assumptions are listed in Appendix A: Candidate Resource Assumptions.

3.2.2 Existing Renewable Resources

Table 3-2 lists El Paso Electric's existing renewable resources. El Paso Electric currently has 115 MW of solar PV generating capacity in its resource portfolio.

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[20] For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.

[21] EPE filed for an application with NMPRC for abandonment on Oct 6, 2020 (Case No. 20-00194-UT). RG 6 is no longer included in EPE Official L&R.

[22] In all cases, no capacity from Palo Verde 3 is assigned to New Mexico jurisdiction customers. Palo Verde 3 is included in the modeling, but it is assumed that it serves Texas jurisdiction customers.

Table 3-2. Existing Renewable Resources

Resource	Resource Type	Nameplate Capacity (MW)	Jurisdiction	Planned Retirement Year[23]
Hatch	Solar	5	NM	2036
Chaparral	Solar	10	NM	2037
Airport	Solar	12	NM	2037
Roadrunner	Solar	20	NM	2031
Macho Springs	Solar	50	System[24]	2034
Newman[25]	Solar	10	TX	2044
Texas Community	Solar	3	TX	2047
Holloman	Solar	5	NM	2048

3.3 Planned Resources

Table 3-3 lists El Paso Electric's planned resources – resources that are either under contract or under development and are expected online. El Paso Electric plans to add 270 MW of solar PV, 50 MW of storage, and 228 MW of natural gas-fired capacity by 2023.

Table 3-3. Planned Resources

Resource	Resource Type	Nameplate Capacity (MW)	Jurisdiction	COD	Planned Retirement Year[26]
Buena Vista Energy Center 1	Solar/Storage	100/50	System[24]	May 2022	2042
Buena Vista Energy Center 2	Solar	20	NM	May 2022	2042
Hecate Energy Santa Teresa 1	Solar	100	System24	Dec. 2022	2042
Hecate Energy Santa Teresa 2	Solar	50	NM	Dec. 2022	2042
Newman 6	Gas Peaker	228	TX[27]	May 2023	2063

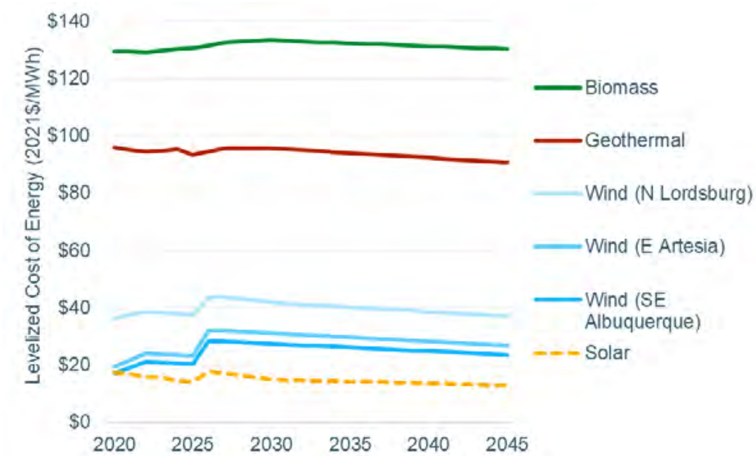
3.4 Candidate Renewable Resources

This study considers several renewable resources as future resource addition options, including solar (at nine locations), wind (at three locations), geothermal (at two locations), and biomass. Figure 3-6 shows the levelized costs of these resources. The levelized cost cannot be utilized in isolation as the basis for portfolio selection because it does not account for all costs, including the potential need for distribution and/or transmission upgrades, nor does it account for the benefits of resources, which depend on their

[23] For resources under contract, the retirement year corresponds to the final year of the contract. For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.
[24] System allocation for TX/NM corresponds to approximately 80/20.
[25] Newman Solar allocates 8 MW to Texas and 2 MW to the EPE Community Solar Program.
[26] For resources under contract, the retirement year corresponds to the final year of the contract. For modeling purposes, E3 assumed that all generators remain online through the end of their planned retirement years.
[27] Newman Unit 6 was rejected by the New Mexico Public Regulations Committee. EPE plants to continue permitting and planning for construction of Newman 6 to serve Texas customers' energy demand in 2023 and beyond.

operating characteristics and ability to serve load. The $/kW-yr levelized cost is the direct resource portfolio optimization input for all resources. Resource costs are described in more detail in Appendix A: Candidate Resource Assumptions. The following sections describe each of the candidate renewable resources in more detail.

Figure 3-6. Levelized Cost of Renewable Resources



3.4.1 Solar PV

The study considers candidate solar PV resources in nine different zones, which span a wide geographic area across El Paso Electric's service area. Each zone differs in the hourly profile of solar production, the amount of headroom on the transmission system, and the cost to upgrade transmission to increase headroom. Table 3-4 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-4. Solar PV Candidate Resource Zones

Resource Zone	State	Coordinates[28]	Capacity Factor[29]
Eastside	TX	(31.7, -106.1)	33.2%
Van Horn	TX	(31.0, -104.8)	31.9%
Holloman	NM	(32.9, -106.0)	32.3%
Santa Teresa	TX	(31.8, -106.7)	33.1%
Hatch	NM	(32.7, -107.2)	32.5%
Luna	NM	(32.3, -107.6)	32.5%
Hidalgo	NM	(32.4, -108.6)	32.7%
Chaparral	NM	(32.1, -106.4)	32.7%
Las Cruces Airport	NM	(32.3, -106.9)	33.0%

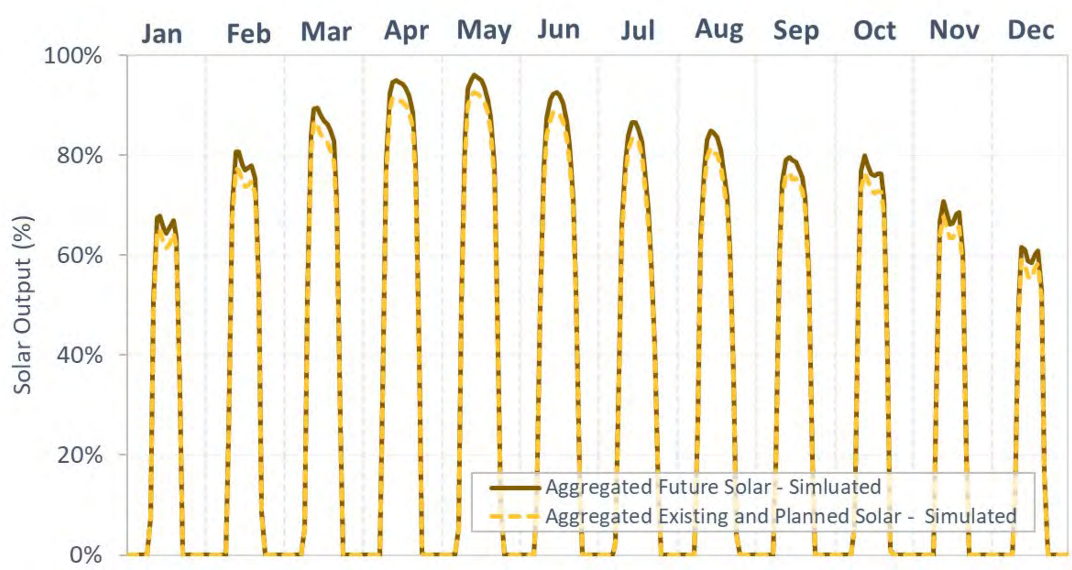
E3 simulated hourly solar generation profiles for each solar PV zone. E3 used hourly insolation data from the National Solar Radiation Database (NSRDB) for the years 2008 to 2018 to create production profiles using the System Advisor Model (SAM) from the National Renewable Energy Laboratory (NREL). SAM produces hourly energy generation using hourly locational insolation and temperature data, PV panel type, tilt, inverter loading ratio, and system characteristics.

The solar production profile for each zone differs hour to hour based on historical weather observations, but the average production profile over the course of a year is similar across the different zones. Figure 3-7 shows the average daily production profile for each month, averaging across the different zonal profiles.

[28] These locations are not meant to represent precise future project locations. The coordinates are used to simulate representative profiles for the corresponding resource zone.

[29] The capacity factor is the ratio of average annual power output, excluding any potential curtailment, to the maximum power output. The capacity factor does not correspond to the ELCC of a resource because the ELCC depends on a resource's ability to reduce loss-of-load events, which depends on the magnitude and timing of a resource's generation.

Figure 3-7. Average Simulated Solar PV Profile by Month



3.4.2 Wind

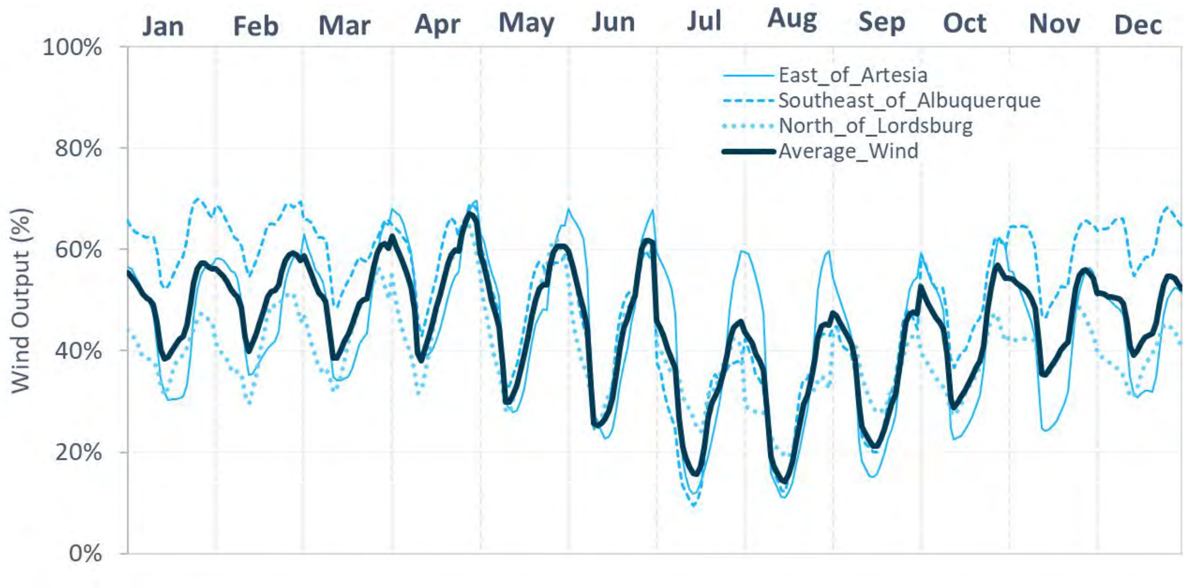
The study considers candidate wind resources in three different zones, which include areas with high-quality wind resources. Each zone differs in the timing and magnitude of wind production. For all wind zones, incremental transmission is needed to deliver the wind energy to El Paso Electric's load centers. Table 3-5 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-5. Wind Candidate Resource Zones

Resource Zone	State	Coordinates[28]	Capacity Factor[29]
East of Artesia	NM	(33.2, -104.0)	44.1%
North of Lordsburg	NM	(32.3, -107.8)	37.1%
Southeast of Albuquerque	NM	(34.8, -105.2)	50.8%

E3 simulated hourly wind generation profiles for each wind zone. To do this, E3 utilized hourly weather data from the Wind Integration National Dataset Toolkit from NREL for the years 2007 to 2013. The wind production profile for each zone differs hour to hour based on historical weather observations, but the average seasonal and daily patterns are relatively similar across the different zones. Figure 3-8 shows the average daily production profile for each month, averaging across the different zonal profiles.

Figure 3-8. Average Simulated Wind Profiles by Month



3.4.3 Geothermal

The study considers candidate geothermal resources in two different zones. Table 3-6 lists the different zones, and Section 3.6 describes the transmission characteristics of each zone.

Table 3-6. Geothermal Resource Zones

Resource Zone	State	Capacity Factor[29]
Northwest El Paso	NM	80.0%
Southeast of Albuquerque	NM	80.0%

Figure 3-9 shows the average daily geothermal production profile for each month. E3 utilized a profile from Black & Veatch's Western Renewable Energy Zones (WREZ) model that corresponds to the production profile expected for geothermal in New Mexico. The profile shows variations by season and time of day. Generation is lower during summer months and during daytime hours when temperatures are higher. This is because the plant's efficiency decreases as temperature increases. The annual capacity factor is 80%.

Figure 3-9. Average Simulated Geothermal Profile by Month

3.4.4 Biomass

The study considers biomass as a candidate resource. A biomass plant would burn organic material to generate electricity.

3.5 Other Candidate Resources

In addition to renewable resources, the study also considered storage, natural gas, and demand resources as candidate resource options. All costs are summarized in Appendix A: Candidate Resource Assumptions.

3.5.1 Storage

Two types of new storage resources are considered in the study: standalone storage and storage paired with solar. Paired storage resources have lower costs because they leverage shared facilities with solar PV resources (e.g., interconnection, inverter) and can take advantage of the investment tax credits (ITC). In both instances, the storage resources are assumed to have a duration of 4 hours and a round-trip efficiency of 85%.

3.5.2 Combustion Turbines

New combustion turbines are included as resource options in some of the cases. The cost of combustion turbines includes capital expenditures, fixed operating and maintenance (O&M), pipeline reservation fees, variable O&M costs, and fuel costs, including startup costs. The study assumes all new combustion turbines burning natural gas can be converted later to burn a high share of hydrogen fuel. However, only a subset of cases include hydrogen as a fuel option.

Some cases include hydrogen as a fuel option, while others do not. In addition, some cases assume existing natural gas units can be retrofitted to burn hydrogen. In this study, all hydrogen fuel is produced from dedicated renewable resources and thus is zero-carbon. The hydrogen fuel assumptions are described in more detail in Section 3.7.2 below.

3.5.3 Demand Response

For demand response, this study considers the potential to expand El Paso Electric's smart thermostat program. Up to 25 MW of capacity can be added by 2030 and up to 50 MW by 2040. The smart thermostat program allows for up to twelve calls during the summer, with each call lasting at most four hours.

3.6 Transmission

The study included a simplified representation of the existing transportation topology, described in Section 3.6.1, as well as the option to expand transmission capacity between simplified transmission zones, described in Section 3.6.2.

3.6.1 Existing Transmission

El Paso Electric's existing transmission topology provides access to local generating resources close to load centers as well as remote generation from the Palo Verde Generating Station via Path 47.

In this study, El Paso Electric's local generating resources are located within the El Paso Electric zone. In addition to the local resources, Path 47 allows imports of both power from the Palo Verde Generating Station and from unspecified imports via spot market purchases. All market purchases are priced based on E3's market price forecast for the Palo Verde hub, which is described in more detail in Appendix B: Price Assumptions. Imports via Path 47 are limited at El Paso Electric's share of firm transmission rights, which is 645 MW. This capacity is used in most hours to import power from El Paso Electric's share of Palo Verde (622 MW). Unspecified imports via spot market purchases are not a sizable portion when all three Palo Verde units are operational, but their share could increase when there is a refueling outage at one of the Palo Verde units, which could occur in fall or spring, depending on the refueling schedule.

El Paso Electric also has 133 MW of transmission capacity to the Eastern Interconnect via the Eddy line. In this study, the line is used for reliability purposes only.

3.6.2 Transmission Expansion

The study includes the option to make upgrades to El Paso Electric's existing transmission system and to add new transmission for purposes of integrating a greater share of remote renewable resources. Figure 3-10 shows the representation of renewable energy zones and transmission expansion options.

The renewable energy zones reflect locations where new renewable resources can be added and interconnected to El Paso Electric's system. Solar projects can be added in a variety of places, many close to load. Wind resources are generally more remote and may require new transmission and/or upgrades to existing transmission. Geothermal resources are expected to be available in two of the modeled renewable energy zones.

The dotted lines reflect options to build new transmission lines. The solid lines reflect existing transmission paths that have some headroom to integrate additional resources but that could be upgraded to integrate additional resources beyond these levels. Some resources would compete for utilizing this existing headroom. For example, both East of Artesia wind and North El Paso solar PV would compete for any available headroom from Northeast El Paso to load centers. Similarly, Northwest El Paso solar and Northwest El Paso geothermal would compete for any available headroom from Northwest El Paso to load centers. Any existing path can be upgraded, and in this study, there are no limitations placed on upgrades to integrate additional resources. The amount of available headroom for each zone, as well as the cost of building new lines or upgrading transmission pathways, is summarized in Table 3-7.

Figure 3-10. Renewable Energy Zones and Transmission Expansion Options

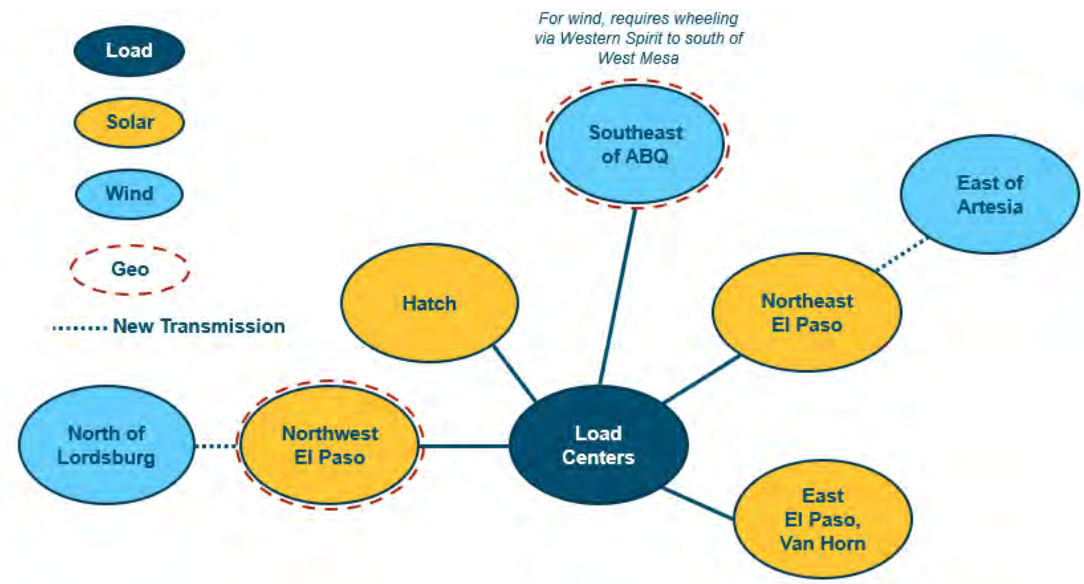


Table 3-7. Transmission Upgrade Costs for Candidate Renewable Resources

Transmission Zone	Downstream Transmission Zone	Assumed Available Capacity Before Upgrades (MW)	Upgrade Length (miles)	Upgrade Voltage (kV)	Upgrade cost ($/kW-yr)[30]
Load Centers	n/a	150	n/a	n/a	n/a
Northeast El Paso	Load Centers	100	75	115	$22.5
East El Paso	Load Centers	100	40	115	$22.5
Van Horn	Load Centers	40	120	115	$30.7
Hatch	Load Centers	40	25	115	$30.7
Northwest El Paso	Load Centers	200	55	345	$55.5
North of Lordsburg	Northwest El Paso	0	50	345	$41.5
East of Artesia	Northeast El Paso	0	200	345	$56.9
Southeast of ABQ[31]	Load Centers	300	125	345	$65.4

3.7 Fuel Prices

This section provides the fuel price assumptions for thermal resources, both existing and new, including plants consuming natural gas, hydrogen, nuclear, and biomass fuels.

3.7.1 Natural Gas

El Paso Electric provided natural gas price forecasts for GasInter,[32] NewInter,[33] and GasIntra[34] through 2029. E3 trended the gas prices upward through 2045 in line with the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO).

Figure 3-11 shows the forecasts for natural gas prices.

[30] These upgrade costs are estimated based on data from El Paso Electric. Any potential transmission upgrades in the future would require more detailed engineering and cost estimate analysis.

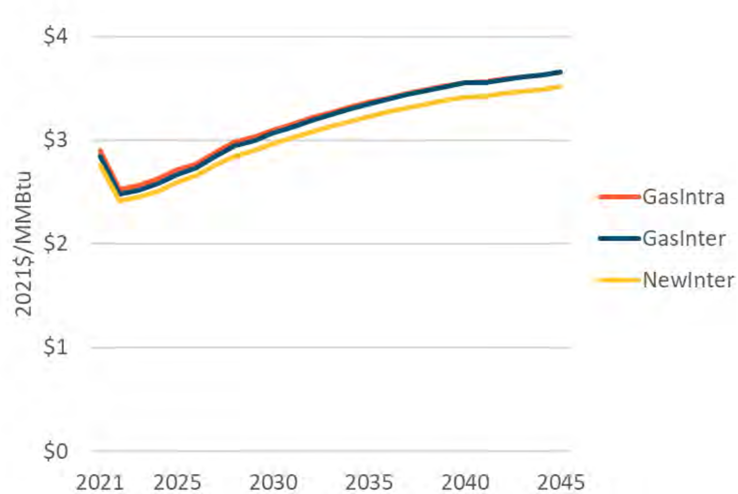
[31] Separate from transmission investments, procuring wind in this location would require wheeling power over the Western Spirit line to El Paso Electric transmission facilities. The modeling assumes a rate of $35,912/MW-yr, which corresponds to the wheeling rate for Public Service Company of New Mexico (PNM).

[32] GasInter is interstate gas with service provided by EPNG. This gas is utilized at the Rio Grande power plant.

[33] 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

[34] GasIntra is intrastate gas with service provided by Oneok. The gas is utilized at the Newman and Copper power plants.

Figure 3-11. Natural Gas Price Forecasts



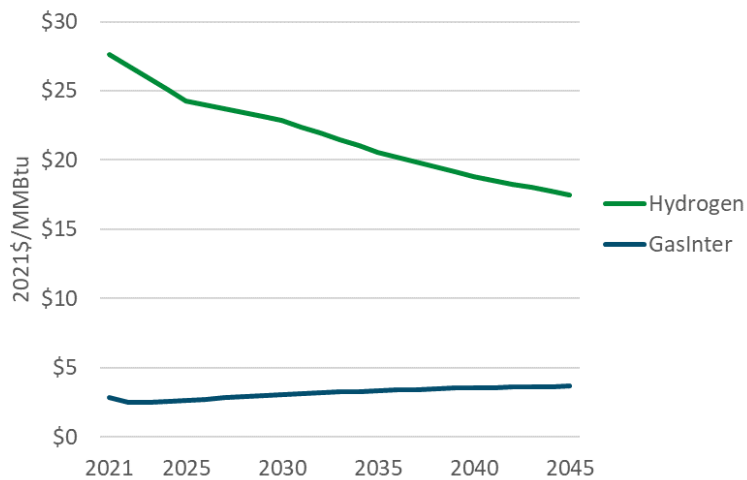
3.7.2 Hydrogen

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. E3 assumed that dedicated renewable facilities are built to produce the green hydrogen. The cost of these facilities is included in the cost of green hydrogen fuel, but these renewable resources are not included in results charts showing resource additions for the cases. The assumptions and methodology for the hydrogen fuel price forecast are described in more detail in a report that E3 prepared for Advanced Clean Energy Storage (ACES),[35] which is a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC.

Figure 3-12 shows the forecast for green hydrogen prices. While E3 forecasts that the cost of producing green hydrogen will drop significantly over the modeling horizon, the price forecast for this zero-carbon fuel is still higher than that of natural gas.

[35] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

Figure 3-12. Green Hydrogen Price Forecast



3.7.3 Other Fuels

For Palo Verde, E3 utilized the uranium price forecast from the EIA 2020 AEO. This starts at $0.71/MMBtu (in 2021 $) and rises to $0.75/MMBtu (in 2021 $) by 2045. For new candidate biomass resources, E3 utilized the biomass price forecast from the 2020 NREL ATB. This is $3.18/MMBtu (in 2021 $) and remains constant through the modeling horizon.

4 Planning Reserve Margin Results

This section presents the planning reserve margin (PRM) results for the system. Section 1.3.1 describes the PRM conceptually, and Section 2.1 describes the methodology.

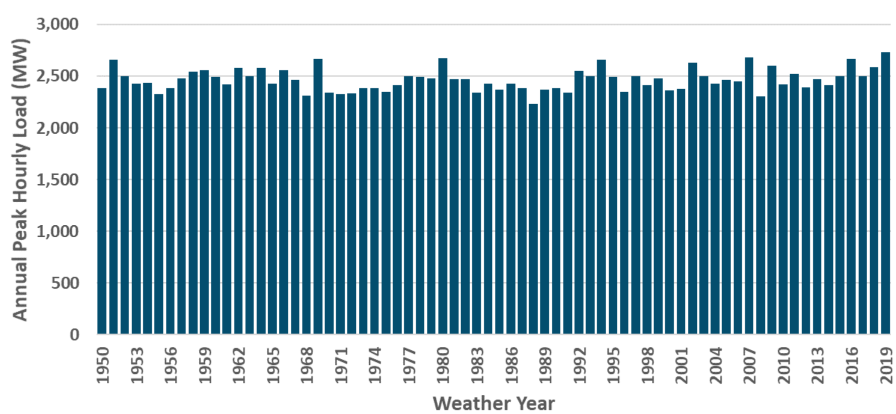
4.1 Load Simulation

In this study, energy demand includes two components: existing end uses and future electric vehicle (EV) energy demand. Distributed generation from existing facilities is included in the existing end uses component, whereas generation from new facilities is treated as energy supply and is not netted against energy demand.

For existing end uses, E3 utilized ten years of El Paso Electric load data (2010-2019) and seventy years of weather data (1950-2019) to simulate the system under a wide variety of weather conditions. For EV load, E3 utilized a managed charging profile. Section 3.1 describes the load forecast and load profiles in more detail.

In each weather year, the annual peak demand varies naturally due to the differences in weather patterns – particularly, due to differences in the highest summer temperatures. Figure 4-1 shows the peak loads – including existing end uses and EV energy demand – for these different weather year conditions, assuming 2030 economic conditions. Some weather years have higher peaks, while others have lower peaks. This study captures the distribution of peak load variability related to weather by simulating load across these 70 weather years.

Figure 4-1. Simulated 2030 Peak Load under Weather Conditions from 1950-2019



The reliability needs of the EPE system today are largely driven by summer peak load events. Table 4-1 contextualizes the magnitude and frequency of gross peak load events for the El Paso Electric system. A 1-in-2 peak load signifies that the annual peak load will exceed this value every other year due to weather variability, while the 1-in-10 peak load signifies that the annual peak will reach this level (or higher) one out of every ten years due to weather variability. The year-to-year peak load variability has a direct impact on the PRM because the PRM must be large enough to ensure that there is enough capacity to meet load during hotter-than-usual years and satisfy the reliability target.

Table 4-1. Distribution of Gross Peak Load Extreme Events in 2030

Metric	Simulated Peak Load for 2030 (MW)
1-in-2 Peak	2,462
1-in-5 Peak	2,553
1-in-10 Peak	2,631
1-in-20 Peak	2,668

4.2 Operating Reserves

In addition to serving load, the system must also maintain a minimum level of operating reserves to respond in the event of contingency events and to balance short-term, sub-hourly fluctuations in load and generation. In this study, E3 utilized El Paso Electric's operating reserve requirements for spinning reserves and regulating reserves (see Table 4-2). If the system cannot serve load while maintaining these operating reserve levels in each hour, then RECAP registers a loss-of-load event.

Table 4-2. Operating Reserve Assumptions for PRM Study

Reserve Type	Description	Quantity
Spinning	Serves as a buffer due to uncertainty related to load levels and generator availability	3.5% of load
Regulating	Ensures balancing of the system on short timescales (e.g., intra-5-minute periods)	35 MW

In addition to these operating reserves, El Paso Electric maintains other reserves during operations, such as non-spinning reserves. While these reserves are important for ensuring reliable operations of the system, they are not included when determining the planning reserve margin because these reserves would be sacrificed in real-time operations to prevent shedding load. In other words, the resources that are being held aside to provide these reserves would be ramped up to minimize loss of load in the case of an emergency.

Spinning reserves and regulating reserves cannot be sacrificed in the same way. These reserves must be held at all times, because if they are not and something unexpected occurs (e.g. loss of generator or transmission line), there could be significant widespread disruptions to electric service.

4.3 Planning Reserve Margin Requirement

E3 calculated the PRM in 2025 and 2030 using RECAP based on the load simulations, operating reserve requirements, and resources. Table 4-3 shows the resultant requirements. In 2025, a PRM of 10% is needed to ensure a 2-day-in-10-year reliability standard, or 0.2 LOLE. In 2030, a PRM of 13% is needed to ensure a 1-day-in-10-year reliability standard, or 0.1 LOLE.

Table 4-3. Planning Reserve Margin Requirements

Metric	Units	2025	2030
Loss of Load Expectation (LOLE)	days/yr	0.2	0.1
Expected System Median Peak	MW	2,245	2,420
Planning Reserve Margin	%	10%	13%
Total Perfect Capacity Need	MW	2,472	2,732

5 Effective Load Carrying Capability Results

This section presents the effective load carrying capability (ELCC) results for renewable, storage, demand response, and thermal resources. Section 1.3.3 describes ELCC conceptually, and Section 2.2 describes the methodology.

5.1 Renewable, Storage, and Demand Response Effective Load Carrying Capability

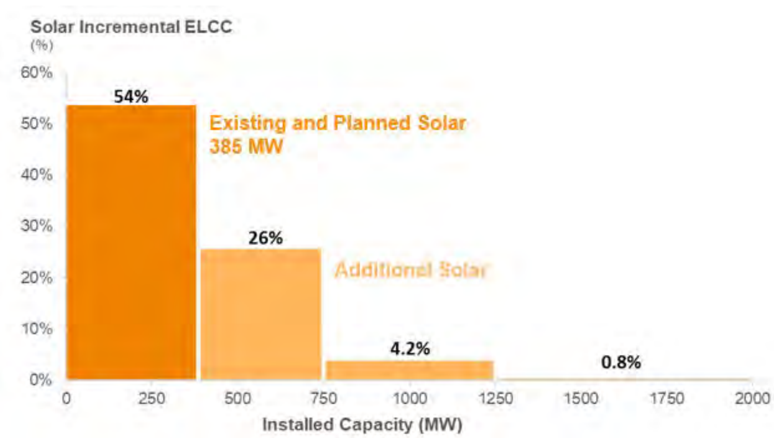
5.1.1 Solar PV

As discussed in Section 1.3.3, solar PV and storage resources have an ELCC diversity benefit. In this study, E3 accounted for this diversity benefit and including it in the resource portfolio optimization analysis. This section presents the ELCC results for solar PV assuming no storage is added to the system. Section 5.1.3 presents the results for solar PV and storage resources, including the ELCC diversity benefit.

Figure 5-1 shows the incremental ELCC for standalone solar added to the system in incremental tranches. The ELCC for existing and planned utility-scale solar resources, which total 385 MW, is 54%. This means that these resources contribute approximately 208 MW toward satisfying the system PRM.

For subsequent tranches of standalone solar, the incremental ELCC declines. As the system adds more solar PV, without adding storage resources, the system reduces the likelihood of loss of load during daytime hours but does not have an impact on nighttime hours. With increasing solar PV capacity, the incremental ELCC declines because the timing of need for capacity shifts to hours when there is little to no solar PV generation.

Figure 5-1. Standalone Solar Incremental ELCC



5.1.2 Storage

This section presents the ELCC results for storage assuming no solar PV is added to the system. Section 5.1.3 presents the results for solar PV and storage resources, including the ELCC diversity benefit.

Figure 5-2 shows the incremental ELCC for four-hour battery storage added to the system in incremental tranches. The ELCC for the planned storage facility, which totals 50 MW, is close to 100%, meaning the nearly the entire 50 MW counts toward satisfying the system PRM.

Figure 5-2. Standalone 4-hour Storage Incremental ELCC

5.1.3 Solar and Storage Surface

As discussed in Section 1.3.3, solar PV and storage resources have an ELCC diversity benefit. In this study, E3 accounted for this diversity benefit by developing a solar-storage ELCC surface and including it in the resource portfolio optimization analysis. Section 2.2.2 describes the ELCC surface concept in more detail.

Table 5-1 shows the ELCC surface results for solar PV and storage, which includes the ELCC diversity benefit. For a given amount of solar PV and storage capacity on the system, the table provides the total ELCC contribution of these resources.

The results illustrate the diversity benefit between solar PV and storage. For example, for 2,000 MW of solar PV and 1,000 MW of storage, the total ELCC is 1,215. However, if solar PV and storage were added to the system in isolation, then they would provide 330 MW ELCC and 656 MW ELCC, respectively. The total of these two ELCC values (986 MW) is less than the ELCC obtained when both resources are added to the system. This difference (229 MW) is the diversity benefit that results from solar PV and storage's mutually beneficial characteristics.

The ELCC diversity benefit for solar PV and storage grows at higher penetration levels. For example, with 2,000 MW of solar PV and 1,000 MW of storage, the ELCC diversity benefit is 1,215 – 330 – 656 = 229 MW, as just discussed, and with 10,000 MW of solar and 5,000 MW of storage, the diversity benefit is 2,312 – 338 – 920 = 1,054 MW.[36]

Table 5-1. Solar and Storage Cumulative ELCC (MW)

Cumulative ELCC (MW)		Solar Cumulative Capacity (MW)							
		0	385	750	1,250	2,000	3,000	6,000	10,000
Storage Cumulative Capacity (MW)	0	0	208	303	324	330	335	336	338
	50	50	258	353	374	380	384	386	388
	200	199	407	504	523	530	535	536	538
	500	459	667	796	821	829	832	837	838
	1,000	656	864	999	1,135	1,215	1,244	1,264	1,270
	3,000	855	1,063	1,179	1,326	1,505	1,655	1,844	1,942
	5,000	920	1,128	1,254	1,403	1,605	1,806	2,096	2,312

See Figure 5-3 for a visual representation of a portion of the solar and storage surface. The figure shows the incremental ELCC for storage assuming different penetration levels of solar on the system (0 MW, 750 MW, 2,000 MW, and 6,000 MW). The incremental ELCC for storage when there is no solar on the system matches what is shown in Figure 5-2. If the system has more solar capacity, then the ELCC for adding additional storage is higher. For example, for the 500-1,000 MW tranche of storage, the incremental ELCC is approximately 40% when there is no solar on the system. If the system has 2,000 MW of solar, then the ELCC for this tranche is above 75%. If the system has 6,000 MW of solar, then the ELCC for this tranche is approximately 85%. For higher solar penetrations, the incremental ELCC for storage declines more gradually. This reflects the diversity benefit of solar and storage.

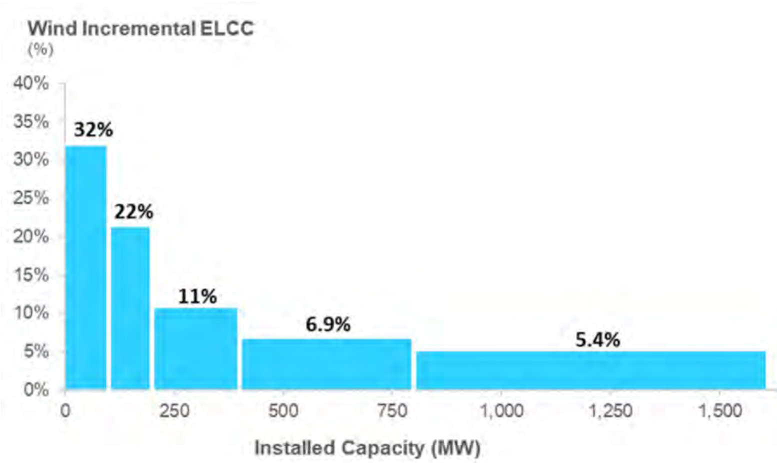
[36] The ELCC of 10,000 MW of standalone solar is 338 MW. The ELCC of 5,000 MW of standalone storage is 920 MW. Accounting for the ELCC diversity benefit, the total ELCC for 10,000 MW of solar PV and 5,000 MW of storage is 2,312 MW. The difference between the sum of the standalone ELCCs and the combined ELCC is the diversity benefit.

Figure 5-3. 4-Hour Storage Incremental ELCC for Different Solar Penetrations

5.1.4 Wind

Figure 5-4 shows the incremental ELCC for wind resources. El Paso Electric does not have any existing or planned wind resources. The first tranche of wind capacity would have an ELCC of 32%. Whereas solar PV generation is more coincident with energy demand for cooling buildings, wind generation is higher during non-summer months and at nighttime, resulting in a lower incremental ELCC at low penetration levels. Subsequent tranches of wind provide the declining incremental capacity value, similar to the effect observed for solar PV.

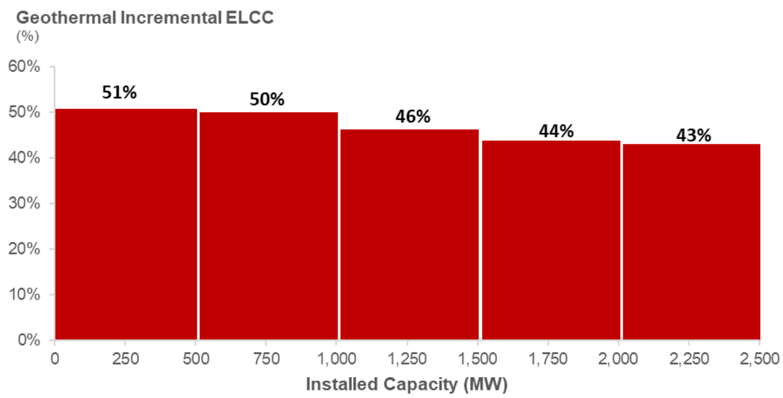
Figure 5-4. Wind Incremental ELCC



5.1.5 Geothermal

Figure 5-5 shows the incremental ELCC for geothermal resources. El Paso Electric does not have any existing or planned geothermal resources. Although the capacity factor of geothermal is 80%, the output profiles have a negative correlation with the load profile, with lower output levels during daytime hours in the summer. For this reason, the ELCC of geothermal is lower than its capacity factor, starting at approximately 50% for the first tranche. Because the geothermal generation profile remains above 40% during all hours, its incremental ELCC does not drop by as much as that of other dispatch-limited resources.

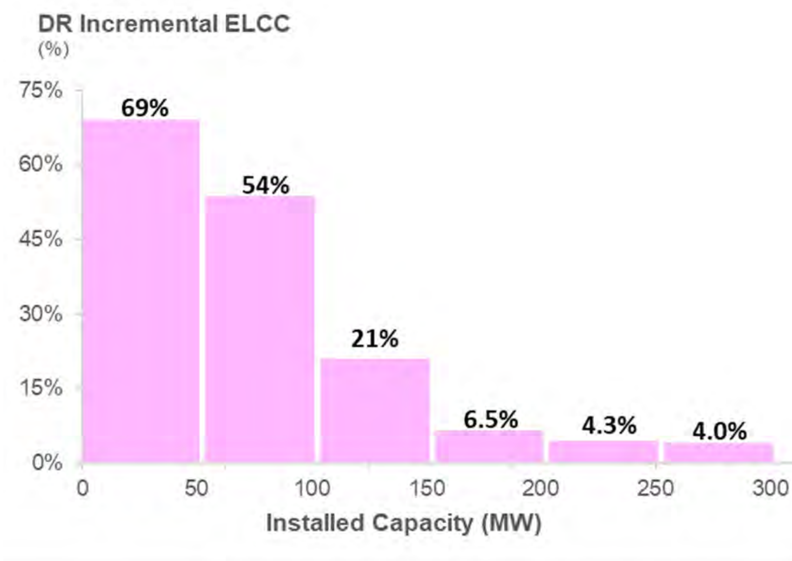
Figure 5-5. Geothermal Incremental ELCC



5.1.6 Demand Response

Figure 5-6 shows the incremental ELCC for demand response. Because the number of calls is limited to twelve calls per summer and the duration of calls is limited to four hours, the ELCC of demand response is less than 100%. The first tranche has an ELCC of 69%. Beyond this level, the ELCC drops further because the subsequent tranches are not as effective at reducing loss of load events, which may last longer than four hours.

Figure 5-6. Demand Response Incremental ELCC



5.2 Thermal Effective Load Carrying Capability

Table 5-2 lists the ELCC results for the existing and planned thermal resources. Because the thermal resources have forced outages, the ELCC is less than 100%. In addition to forced outages at the plant, Palo Verde also includes the effect of potential outages on transmission lines that transport the power to El Paso Electric's load centers.

Table 5-2. ELCC for Thermal Units[37]

Resource	Summer Capacity (MW)	ELCC (MW)	ELCC (%)
Rio Grande 7	46	42	91%
Rio Grande 8	144	130	90%
Rio Grande 9	86	78	90%
Newman 1	73	67	91%
Newman 2	73	67	91%
Newman 3	90	82	91%
Newman 4	227	197	87%
Newman 5	266	239	90%
Newman 6	228	206	90%
Copper	63	57	90%
Montana 1	88	79	90%
Montana 2	88	79	90%
Montana 3	88	79	90%
Montana 4	80	72	90%
Palo Verde	622	587	94%

[37] E3 calculated specific ELCC values for Rio Grande 7, Newman 1-4, and Palo Verde. The ELCC values for all other units are based on the average ELCC across all units.

6 Portfolio Analysis

This section presents resources portfolios for the El Paso Electric system, including resource portfolios specific to the New Mexico jurisdiction. Section 6.1 summarizes the results of the Least-Cost case. Section 6.2 describes technical aspects of the New Mexico's Renewable Energy Act (REA) that could impact the optimal portfolio selection. Section 6.3 describes three different REA cases and how they could impact the resource portfolio for the New Mexico jurisdiction. Section 6.4 presents the results of each of the REA case, and Section 6.5 presents the detailed results for one of the cases.

6.1 Least-Cost Case

The Least-Cost case does not impose any constraints on the resource portfolio beyond reliability requirements. This case identifies the optimal least-cost portfolio before considering clean energy requirements or allocation of resources between the New Mexico and Texas jurisdictions. These considerations are discussed in detail in subsequent sections.

The Least-Cost case provides a reference point for comparing all other REA cases. If additional constraints are added to the Least-Cost case, such as more aggressive clean energy policies, then the resulting optimal portfolio will be more expensive because the Least-Cost case already has a least-cost optimal mix of resources. By comparing alternative cases to the Least-Cost case, the analysis can identify the impacts of these additional constraints. Alternative cases are discussed in Sections 6.3 and 7.

6.1.1 Resource Additions and Retirements

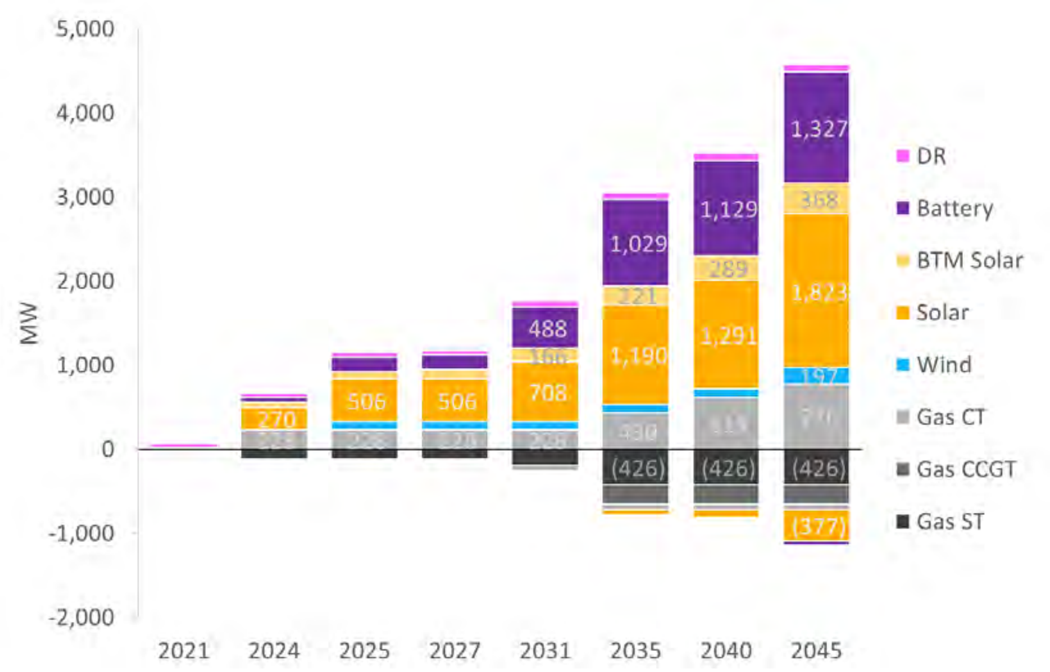
See Figure 6-1 for the cumulative resource additions and retirements through 2045 in the Least-Cost case. The additions through 2024 are planned resources, including the Newman 6 unit, solar and storage capacity, and demand response capacity. In 2025, the first year of the resource portfolio optimization, EPE would add 236 MW of solar, 127 MW of storage, and 102 MW of wind capacity.

In the period 2026-2031, EPE would add 202 MW of solar and 311 MW of storage, in part to replace thermal capacity retirements. The storage resources contribute to the reliability needs created by load growth and thermal retirements and assist with the integration of increasing levels of renewable generation.

In the period 2032-2045, EPE would add 1,114 MW of solar, 839 MW of storage, 96 MW of wind, and 548 MW of gas combustion turbine (CT) capacity. Over this period, significantly more thermal units retire. While the solar, storage, and wind resources contribute to replacing this capacity and satisfying the PRM, the optimal least-cost portfolio also adds gas plant capacity to ensure reliability.

Through 2045, more than 80% of all resource additions are renewable generators, storage, or demand response. Through 2045, gas resources account for most resource retirements.

Figure 6-1. Cumulative New & Retired Capacity in Least-Cost Case



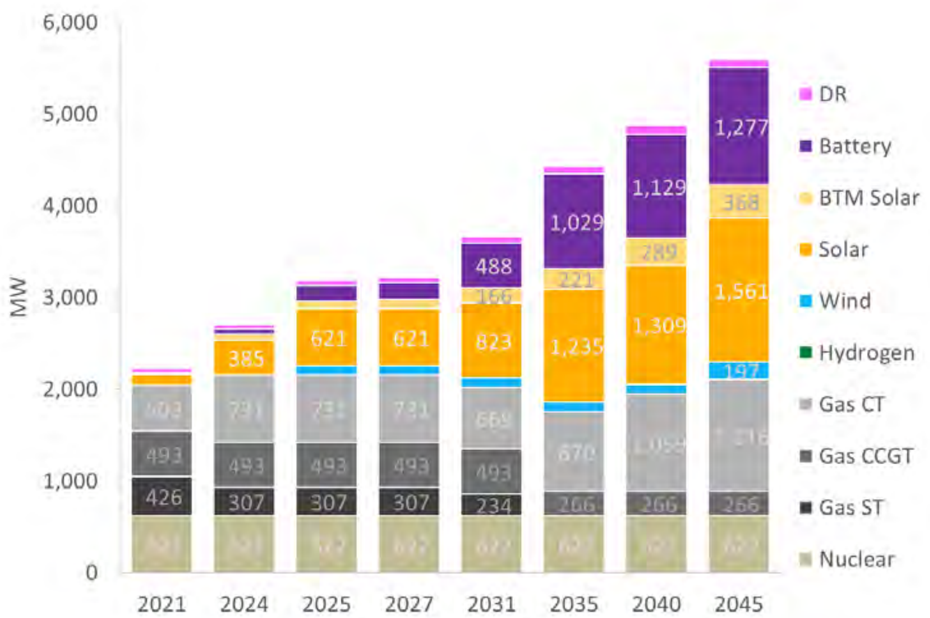
6.1.2 Total Capacity

See Figure 6-2 for the total capacity through 2045 in the Least-Cost case. In addition to resource additions and retirements discussed in the previous section, this figure includes resources that are online today and will remain online through the planning horizon.

This figure shows a significant transition in the resource mix through 2045. Currently, El Paso Electric's resource portfolio consists mostly of thermal capacity from nuclear units at Palo Verde and natural gas plants. Through 2045, the diversity within the resource portfolio increases as solar, storage, wind, and demand responses resources are added. By 2025, solar capacity approximates EPE's share of capacity at Palo Verde. By 2035, solar capacity exceeds gas capacity. Storage capacity increases in tandem with solar capacity. Storage resources help shift solar generation from periods of abundant solar generation (i.e., daytime) to periods of low solar generation (i.e., nighttime).

Natural gas capacity increases with the addition of Newman 6 but then declines through 2035. Natural gas capacity increases again during the periods 2035-2045 but remains below 2024 levels in 2045.

Figure 6-2. Total Capacity in Least-Cost Case



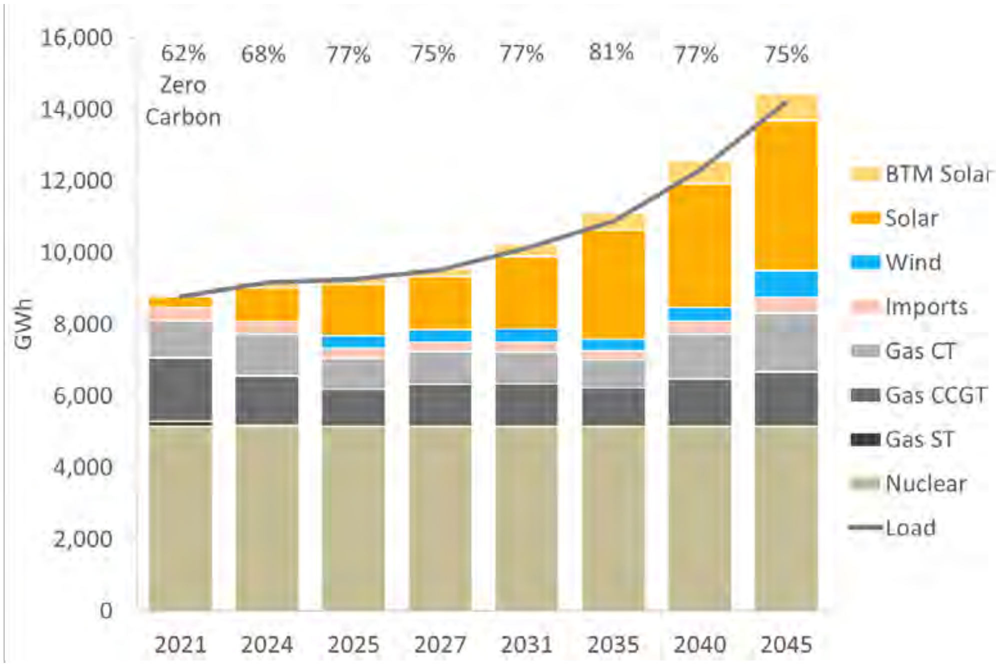
6.1.3 Generation Mix

See Figure 6-3 for the annual generation through 2045 in the Least-Cost case. This shows the amount of generation by resource, based on optimal hourly dispatch dynamics.

The EPE system already has a high share of zero-carbon energy with the generation from Palo Verde. Between the generation from Palo Verde and solar facilities, the share of total generation from zero-carbon energy sources is estimated to be 62% in 2021. Despite energy demand increasing through 2045, the share of energy from zero-carbon energy sources increases to 75% or higher in the 2025-2045 period. This is because renewable generation accounts for an increasing share of the energy mix through 2045.

Generation from natural gas plants decreases through 2025, remains relatively constant through 2035, and then rises through 2045. This generation occurs during periods of insufficient energy available from other resources, including nuclear, renewables, and storage. While more renewable and storage capacity could be added to reduce gas generation further, this would add costs and thus is not part of the optimal least-cost portfolio. Further reductions in gas generation are explored through several carbon reduction sensitivities, which are discussed in Section 7.1.

Figure 6-3. Annual Generation in Least-Cost Case



6.1.4 Planning Reserve Margin and Reliability

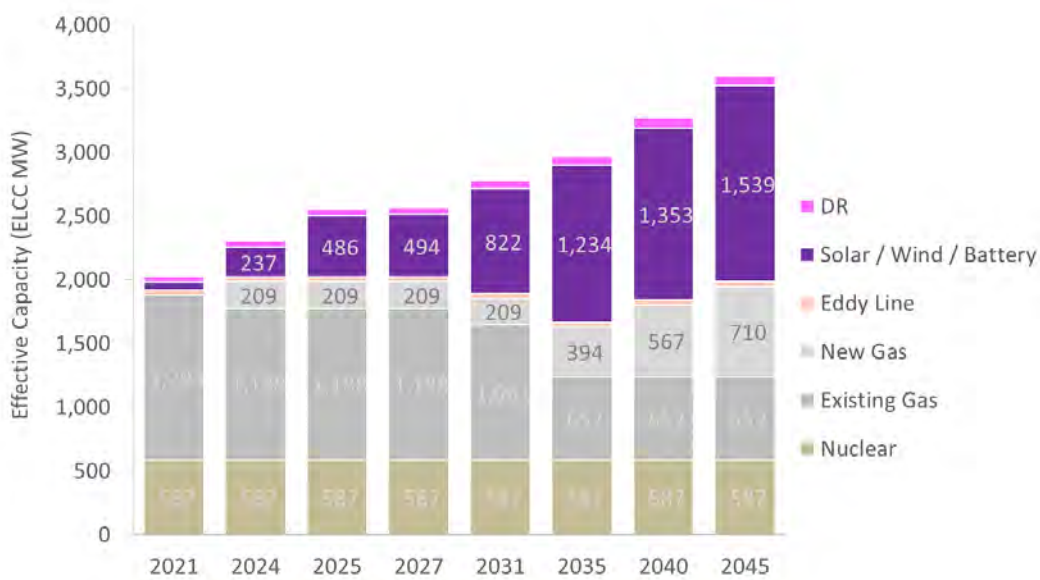
See Figure 6-4 for the effective capacity through 2045 in the Least-Cost case. The effective capacity is the amount of capacity that can be counted toward the PRM for ensuring reliability.

The minimum requirement for effective capacity is a function of peak energy demand and the PRM. As discussed in Section 3.1.1, peak demand grows through 2045. As discussed in Section 0, the PRM increases from 11% in 2025 to 13% in 2030. These two factors result in an increase in the requirement for effective capacity over time.

In addition to the increase in this requirement over time, the retirement of existing capacity results in an increasing need for new resources to ensure reliability. The amount of effective capacity from existing resources declines by 105 MW between 2021 and 2024, by 127 MW between 2027 and 2031, and by 409 MW between 2031 and 2035.

The growing capacity need is met through a combination of renewables, storage, demand response, and gas resource additions. Renewable and storage resources account for approximately 80% of effective capacity additions by 2031 and more than 70% by 2045. While the total effective capacity for renewable and storage resources increases through 2045, the effective capacity per nameplate capacity declines. As discussed in Section 5.1, this occurs because the incremental ELCC of these resources declines with penetration. The optimal least-cost solution adds gas resources 2035-2045 to contribute additional effective capacity.

Figure 6-4. Effective Capacity in Least-Cost Case



6.2 REA Requirements

For investor-owned electric utilities in New Mexico, the state's REA establishes the following targets for renewable and carbon-free energy:

- Renewable energy must comprise at least
  - 40% of all retail sales of electricity in New Mexico by 2025;
  - 50% of all retail sales of electricity in New Mexico by 2030; and
  - 80% of all retail sales of electricity in New Mexico by 2040 (provided that compliance until 2047 does not require the utility to displace zero-carbon resources).
- Zero carbon resources must supply 100% of all retail sales of electricity in New Mexico by 2045.

El Paso's anticipated portfolio in 2040 for serving New Mexico customers includes nuclear generation from Palo Verde (units 1 and 2) that accounts for more than 20% of New Mexico retail sales, leaving less than 80% of New Mexico retail sales to be supplied by renewables. Therefore, this study assumes that, by 2040, the full remainder of retail sales not served by zero-carbon nuclear resources must be met with renewable energy. The study models this consideration by requiring that, in 2040, El Paso Electric must begin serving 100% of retail sales in New Mexico using zero-carbon resources (including nuclear generation).

As discussed below, different approaches exist to model a portfolio that meets REA's requirements, particularly for a utility like El Paso Electric that serves customers in multiple states. Defining the approach used is required to model an optimal portfolio that meets these requirements.

System-Wide Renewable Procurement vs. State-Specific Portfolios for REA Requirements

As noted in Section 6.1, the Least-Cost case does not impose any specific constraints for meeting clean energy requirements but selects resources solely for minimizing cost while maintaining reliability.

Nevertheless, the resulting system-wide portfolio selected generates total renewable energy in 2040 for the El Paso Electric system that exceeds the sum of renewable energy required to serve 80% of El Paso Electric's retail sales in New Mexico plus the renewable energy required for compliance with Texas policies.

Under this total system approach, the Least-Cost case would meet both states' renewable procurement targets in the aggregate. Dual-state compliance would be demonstrated through the assignment of Renewable Energy Credits (RECs). El Paso Electric's portfolio of renewable resources would deliver energy to its system and generate the total number of RECs, which would be assigned between Texas and New Mexico in amounts required for each state's policy.

Under a state-specific portfolio approach, El Paso Electric renewable and zero-carbon resources would also be procured first for the combined Texas and New Mexico system and then would be allocated proportionally between New Mexico and Texas based on each states' share of overall El Paso Electric load. Under this approach, if New Mexico's proportionally allocated quantity of the system-wide renewable energy procurement is not enough to meet the REA requirement, then El Paso Electric would need to procure additional renewable resources that are specifically designated and assigned to El Paso Electric's New Mexico customers. Additional costs associated with these New Mexico-designated resources would also be assigned to El Paso Electric's New Mexico load customers.

This study has modeled each of these approaches in separate cases.

Annual vs. Hourly Generation Balancing for REA Requirements

Additionally, the REA 100% zero-carbon target for 2045 could be evaluated (a) on a total annual generation basis, or (b) on an hourly generation basis. Each of these approaches was analyzed in this study for modeling zero-carbon generation to serve El Paso Electric's New Mexico load starting in 2040 (including El Paso Electric's generation from Palo Verde). These two approaches are summarized in more detail below in Table 6-1.

Table 6-1. Implications of Annual vs. Hourly Balancing for Zero-Carbon Energy

Annual balancing	Hourly balancing
New Mexico-allocated zero-carbon resources must generate enough energy on an annual basis to match the REA target	New Mexico-allocated zero-carbon resources must serve New Mexico energy demand in all hours of the year
Natural gas resources and/or imports can serve New Mexico's energy needs in some hours if that generation is offset by additional zero-carbon generation in other hours	El Paso Electric's New Mexico load cannot be served by gas resources or unspecified imports in any hour of the year
Annual balancing allows New Mexico customers to receive the benefits of being served by a larger system	Hourly balancing would be a more stringent approach because it would not allow for balancing between New Mexico and Texas resources

Capacity Pooling

When evaluating reliability, a single portfolio of resources serving a larger total customer load level typically will perform more reliably than two smaller groupings of resources separately serving two sub-areas of load. The larger single system allows for resources available in one part of the system to be used to help maintain reliability in the other part of the system, effectively "pooling capacity" for reliability purposes. For these reasons, when capacity pooling is assumed for planning purposes, fewer total resources will be needed for the combined system (and costs will be lower) to maintain a given level of expected reliability, compared to what would be needed for two sub-systems operating independently

For this analysis, El Paso Electric is modeled in the Least-Cost case with capacity pooling enabled between its Texas and New Mexico jurisdictions for reliability purposes. This study also models a case without capacity pooling, which would reflect a more stringent approach to New Mexico's clean energy policy in which resources assigned to El Paso Electric's Texas jurisdiction – which could include gas resources – would not be allowed to provide support to New Mexico loads, even for reliability purposes. Further description of capacity pooling is provided below in Figure 6-5. and Table 6-2.

Figure 6-5. Capacity Pooling Options Considered in the Study

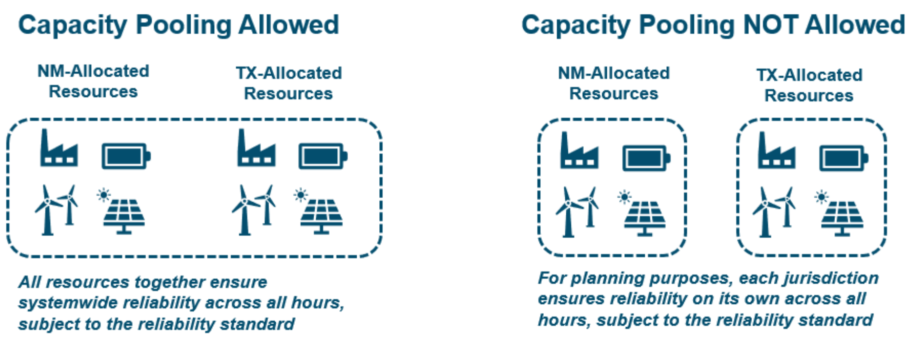


Table 6-2. Implications of Capacity Pooling for Portfolio

Capacity Pooling Allowed	Capacity Pooling NOT Allowed
For reliability planning purposes, El Paso Electric's NM and TX loads can be served by NM resources, TX resources, and/or system resources. If the NM jurisdiction doesn't have enough resources to satisfy load in an hour, then it can rely on TX resources, and vice versa	For reliability planning purposes, TX and NM must each have enough resources separately to ensure reliability across a range of potential conditions without relying on the other jurisdiction (i.e., on a standalone basis)
NM and TX customers incur costs for their proportional share of total system reliability needs	NM customers would incur costs for dedicated resources sufficient to maintain reliability without needing to call upon TX resources in any hour, and vice versa

6.3 REA Cases

In this study, El Paso Electric's REA requirements were modeled at varying levels of stringency under three separate cases. These cases have meaningful implications on how planning is performed for New Mexico customers, the resulting portfolio that is procured, and the resulting costs.

The three REA cases are summarized in Table 6-3.

Table 6-3. REA Cases Analyzed

	Least-Cost ("LC")	Least-Cost + REA Resources ("LC+REA")	Separate System Planning ("SSP")
Portfolio Optimization	Least-cost system optimization	Reoptimize Least-Cost to add additional renewables & storage dedicated to NM to satisfy REA requirements	Optimize NM and TX systems independently without modeling interactions between them
NM Zero-Carbon Generation Balancing Period	Annual	Annual	Hourly
NM and TX Capacity Pooling to Ensure Reliability	✓	✓	✗
Resource Allocation	Resources allocated proportionally	Incremental resources are allocated to New Mexico	Optimization identifies resources specifically for NM and TX jurisdictions
NM Allocated New Gas Capacity	✓	✗	✗

All three cases above exclude the potential for burning green hydrogen fuel as a zero-carbon fuel. An additional case titled "SSP H2" models the Separate System Planning (SSP) case with identical assumptions as the SSP case but with green hydrogen fuel available.

6.3.1 Least-Cost (LC)

In the Least-Cost case, El Paso Electric procures renewable energy on a system-wide basis, exceeding the sum of renewable energy needed to serve 80% of El Paso Electric's New Mexico loads plus El Paso Electric's Texas renewable energy requirement. This case assumes that this form of renewable procurement will satisfy REA compliance. The case also supplies sufficient zero-carbon energy to serve 100% of El Paso Electric's New Mexico loads starting in 2040 and allows pooling of capacity resources. The portfolio optimization is conducted for El Paso Electric's entire service area, and resources (including potential new gas capacity) are allocated to the Texas and New Mexico jurisdictions based on an approximately proportional load share. This case results in the lowest overall system cost.

6.3.2 Least-Cost Plus REA Resources (LC+REA)

In this case, additional zero-carbon resources are dedicated to serving New Mexico customers. Separate resource portfolios for each state are developed in three steps in this case. First, a preliminary portfolio of resources is selected based solely on minimizing costs; this portfolio matches the resources that were selected in the Least-Cost case. Second, the resources from this preliminary portfolio are allocated between Texas and New Mexico proportionally to the size of El Paso Electric's customer loads in each state. More of El Paso Electric's customers are in Texas than in New Mexico, so this allocation results in a larger share of renewable projects being allocated to Texas customers and a lower amount of renewable projects being allocated to New Mexico customers.

In the third step, the model selects additional renewable and storage resources to ensure there is sufficient renewable and zero-carbon energy to satisfy the New Mexico REA targets. These incremental resource additions and associated costs are fully allocated to New Mexico customers. New gas capacity can be selected in this case, but it is exclusively assigned to Texas customers, and the total quantity of new gas additions in the model is not allowed to exceed the amount of new gas that was allocated to Texas from the preliminary portfolio. This case allows pooling of capacity resources for reliability purposes.

6.3.3 Separate System Planning (SSP)

As the most stringent approach, the Separate System Planning (SSP) case models the Texas and New Mexico jurisdictions as two separate systems that do not interact with each other for energy transactions or for reliability planning.

This case requires zero-carbon generation for New Mexico in all hours in 2040 and beyond. While the Least-Cost and LC+REA cases described are evaluated based on the renewable and clean energy available as a percentage of retail sales, the SSP case requires that 100% of energy generation for the New Mexico system, including transmission and distribution losses, must be zero-carbon in every hour for 2040.

While zero-carbon energy can be exported from the New Mexico system in an hour when it has more than is needed for loads, these exports do not enable it to have non-zero-carbon imports (or generate from carbon-emitting local resources) in different hours, because the requirement applies individually to every hour of the year. Capacity pooling for reliability purposes is not allowed in this case, and no new gas resources are allocated to New Mexico.

6.3.4 Separate System Planning with Hydrogen (SSP H2)

The first three REA cases (LC, LC+REA, and SSP) do not include the option to burn green hydrogen as a zero-carbon fuel. This final case (SSP H2) reflects all the same assumptions as the SPP case, but it allows green hydrogen to be combusted as a zero-carbon fuel.

6.4 REA Case Results

This section compares the resource capacity, generation, and cost of each of the REA cases described above.[38] For each case, this section highlights the changes to the portfolio of the El Paso Electric system as a whole, as well as the resources and costs allocated to El Paso Electric's New Mexico customers.

6.4.1 Capacity

See Figure 6-6 for the capacity (in MW) of El Paso Electric's resource portfolio in 2031 under each REA case. The left panel of the figure shows the capacity of all of El Paso Electric's resources in each case. In the right panel, the chart shows the capacity allocated to El Paso's New Mexico loads.

In the Least-Cost case, new resources are allocated to New Mexico proportional to New Mexico's share of load.[39] In the LC+REA case, any resource additions that are incremental to the LC case are needed to comply with the REA and thus are allocated to New Mexico loads.

Compared to the Least-Cost case (which was described in detail in 6.1.2), the Least-Cost Plus REA Resources case procures a similar amount of most resources on a system-wide basis for 2031 but adds an additional 101 MW of wind procurement (203 MW in LC+REA vs. 102 MW in LC). The New Mexico capacity in the right panel shows that all of this incremental wind procurement is assigned to New Mexico (which shows 122 MW of wind in LC+REA vs. 20 MW in LC). In the portfolio optimization, the additional wind resources added enable the model to select 28 MW less solar (795 MW in LC+REA vs. 823 in LC) and less storage resources while still meeting the renewable procurement and reliability goals. Similar reductions are also reflected in the NM share of capacity in LC+REA.

The SSP case must procure more solar (859 MW vs. 823 MW) and more storage (591 MW vs. 488 MW) resources for the system than the Least-Cost case, and most of these changes are reflected as additions in the New Mexico system's portfolio. These incremental renewable procurement levels would be needed to be on a trajectory to have zero-carbon energy serve New Mexico's load on an hourly basis by 2045, and to have resources to maintain reliability planning targets without capacity pooling of resources with Texas. By contrast, the LC and LC+REA cases are able to export renewables from New Mexico to Texas in some hours and import energy in other hours as long as the system supplies 100% of New Mexico customers'' annual retail load using zero-carbon resources on a net basis by 2045; also, the LC and LC+REA cases use

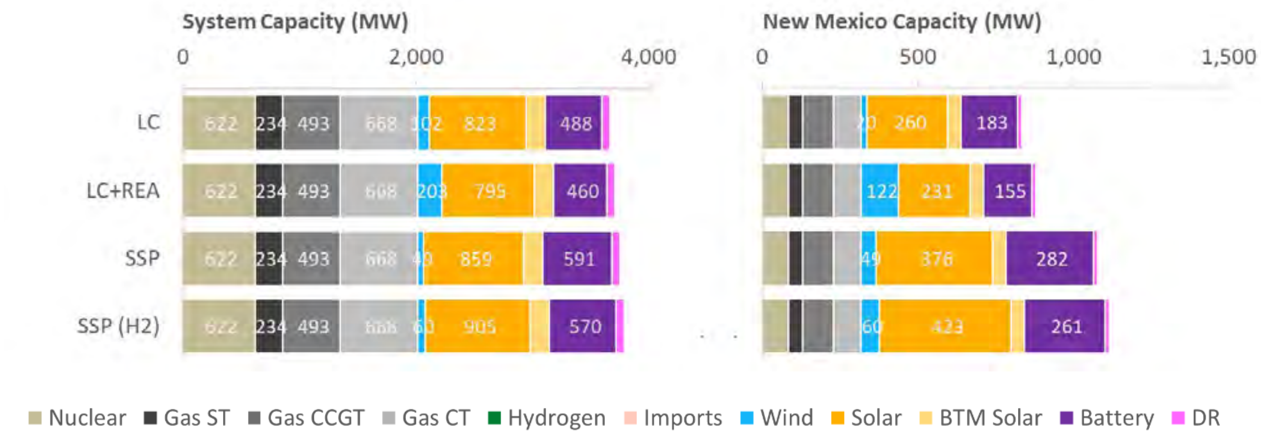
[38] E3 presented draft results for the REA cases at the 2021 El Paso Electric Company Integrated Resource Plan Public Participation June 2021 Meeting. This report presents final results for the REA cases.

[39] Any resources that already have been procured on behalf of New Mexico customers are allocated 100% to New Mexico customers.

capacity pooling to reduce the total resources needed for reliability. The SSP case selects slightly fewer wind resources than in the LC case (likely because more storage was selected for reliability, which shifts economics in favor of solar), but the full 49 MW wind procurement is allocated to New Mexico to serve its rising clean energy target (and stringency for hourly balancing).

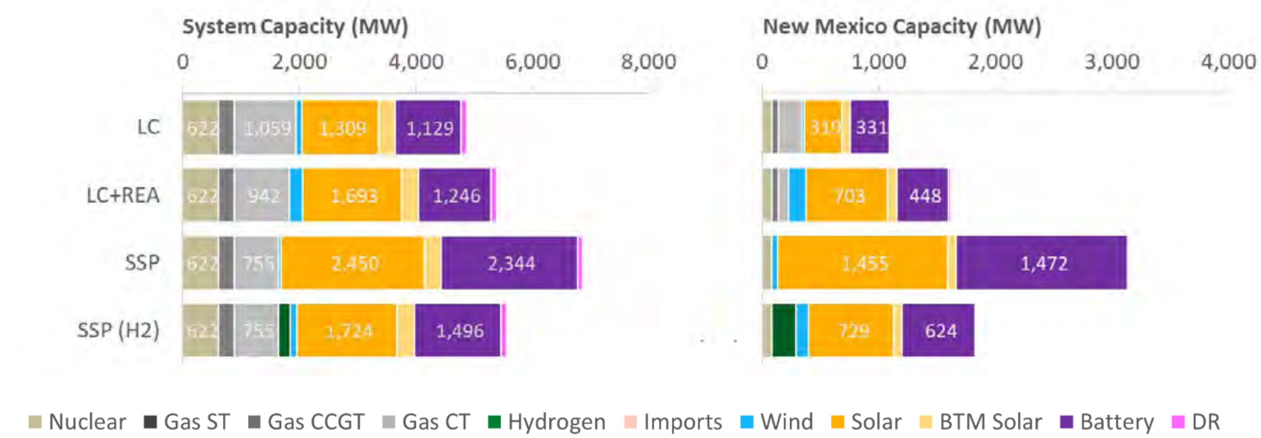
The SSP H2 case selects fewer storage resources in 2031 because the model optimization can anticipate that in 2040 it will be able to use dispatchable H2-fired generation as a complement to renewables and storage to meet the hourly zero-carbon energy balancing and reliability needs of El Paso Electric's New Mexico system. Less storage is needed for New Mexico for this study year (since H2 is going to provide carbon-free dispatchable capacity later), but this also means that slightly more solar must be added in the SSP H2 case to meet the renewable energy target, because the lower storage addition produces in more renewable curtailment.

Figure 6-6. Capacity in 2031 by REA Case



See Figure 6-7 for each REA case's total capacity for the year 2040. Portfolio results in this year diverge more significantly between cases than in 2031 because the zero-carbon energy requirement modeled for New Mexico loads is 100% in 2040.

Figure 6-7. Capacity in 2040 by REA Case



The Least-Cost case's system-wide capacity for 2040 is described in detail in section 6.1.2. Incremental resources selected by the optimization have been allocated proportionally to loads (less output of existing dedicated resources) to produce El Paso Electric's New Mexico capacity for this case, which has a significant quantity of solar and storage resources by this year.

Compared to the LC case, the LC+REA case adds more solar (1,639 MW vs. 1,309 MW) and storage (1,246 MW vs. 1,129 MW), as well as a modest amount of additional wind. These incremental additions would be needed as dedicated New Mexico resources to produce sufficient renewable energy under this approach to modeling REA. In the LC+REA case, the additional renewable and storage procurement enables a reduction in the amount of gas resources needed for reliability purposes (942 MW of gas CTs in LC+REA vs. 1,059 MW in LC). Also, the New Mexico portfolio in the LC+REA case does not have any new gas capacity.

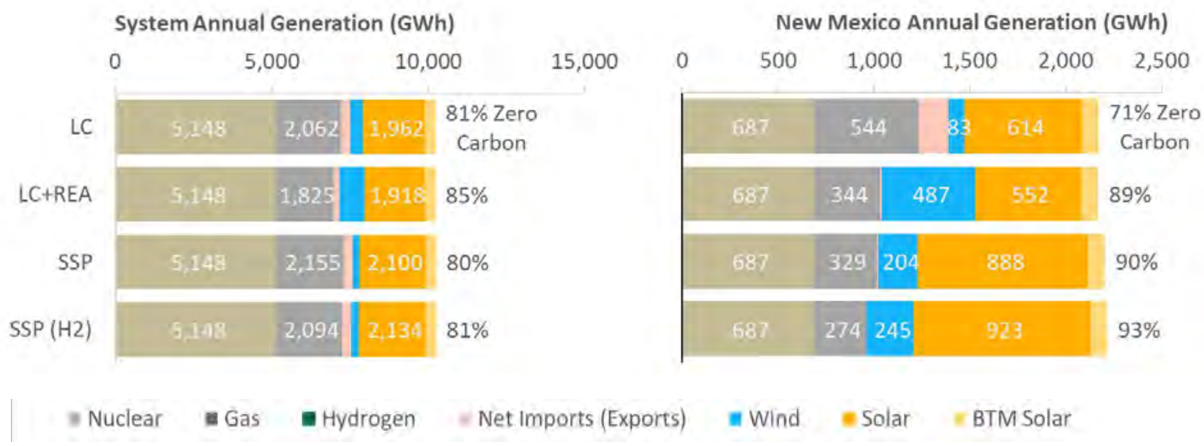
The SSP case must procure significantly more solar resources (2,450 MW total) and storage (2,344 MW total) on a system-wide basis, and most of these incremental resources are allocated to New Mexico loads to enable New Mexico to balance on an hourly basis without any gas generation and to meet a reliability needs as a standalone system without capacity pooling. These large additions are needed for infrequent longer-duration events where the New Mexico separate system needs energy (from clean energy sources for every hour) but faces lower renewable output and/or plant outages. In this case, the additional solar resources are needed in New Mexico to ensure that there is a clean energy source capable of charging the additional storage. As a result of the storage and solar additions, system-wide gas capacity (755 MW) is also lower in the SSP case and entirely assigned to Texas.

The addition of a moderate amount of zero-carbon, dispatchable hydrogen generation to the New Mexico separate system in the SSP H2 case significantly reduces the amount of solar and storage needed for reliability compared to the SSP case, because the H2 generation can cover the infrequent, longer-duration events that challenge reliability on the New Mexico separate system.

6.4.2 Generation

See Figure 6-8 for a comparison of annual generation in 2031 under each REA case. The chart shows the energy in GWh from each fuel type, as well as the percentage of this energy generation that comes from zero-carbon resources. Net imports are shown in the chart and are not treated as clean energy for this calculation.

Figure 6-8. Annual Generation in 2031 by REA Case



The Least-Cost case includes 81% zero carbon generation for 2031. After allocating to New Mexico's loads, zero-carbon resources comprise 71% of New Mexico's annual energy, a lower share than the overall system primarily due to New Mexico's smaller ownership share of Palo Verde nuclear resources as a zero-carbon source. This results in a proportionally higher need for imports and gas dispatch in New Mexico's share of the system even though New Mexico has more dedicated solar resources.

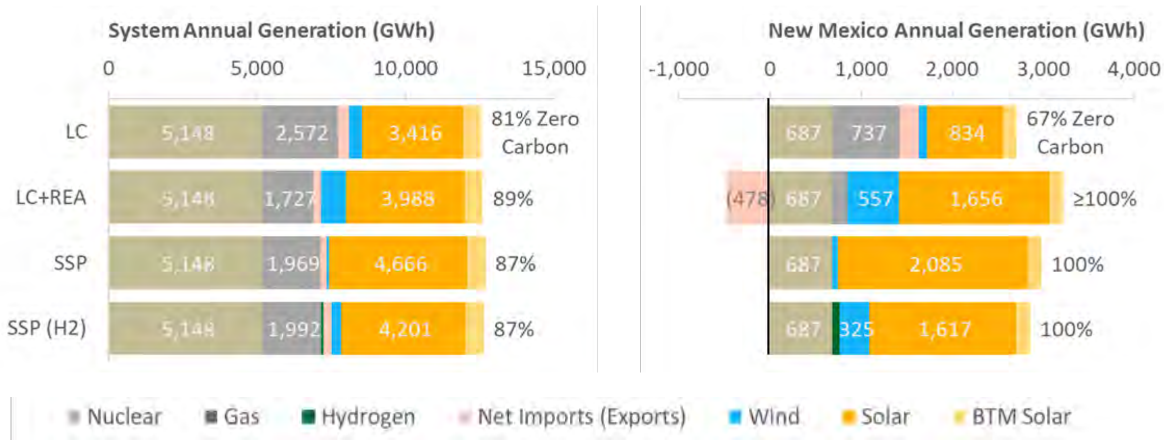
The LC+REA case raises the zero-carbon share of generation to 85% for El Paso Electric overall, and to 89% for El Paso Electric's New Mexico loads. This increase is primarily driven by the additional wind resources procured to meet EA requirements (in an assigned-resource approach) beyond those in the LC case; this additional wind energy reduces the amount of energy generation that is needed from gas units in this case.

The SSP case selects more solar resources assigned to serve the New Mexico loads and assigns a higher share of the overall wind procurement to New Mexico. The additions result in only 1 percent higher zero-carbon generation for New Mexico compared the LC+REA case (90% vs. 89%), however, because the SSP case does not benefit from efficiencies of coordinated balancing between the two portions of the system and therefore faces higher potential renewable energy curtailment in each portion of the system.

The SSP H2 case has similar generation levels as the SSP case on a system-wide basis, but the slightly higher solar build for New Mexico results in slightly lower gas dispatch.

See Figure 6-9 for annual generation totals by REA case for the 2040 period. In the Least-Cost case, the cost minimized portfolio selection results in total renewable energy procurement that exceeds the sum of renewable energy required for New Mexico loads plus the Texas renewable energy target. Zero-carbon resources again comprise 81% of total generation in this case, the same level as for 2031. New Mexico's share of zero-carbon generation is slightly lower in this year (67%) for the LC case because load growth leads to Palo Verde nuclear generation representing a smaller share of overall generation.

Figure 6-9. Annual Generation in 2040 by REA Case



In the LC+REA case, zero-carbon energy rises to 89% of El Paso Electric's system-wide dispatch and represents over 100% of New Mexico's share of annual generation, after accounting for the impact of renewable energy net exports from New Mexico to El Paso's Texas loads or to other utilities in the West. As previously noted, a higher amount of renewable generation capacity was procured in this case (and assigned to New Mexico) and the increased storage allows this generation to not be curtailed as heavily.

The SSP case results in 87% zero-carbon generation for El Paso Electric overall in 2040 (higher than the LC case but lower than the LC+REA case). New Mexico's significant solar and storage resource build allows that portion of the system to balance load with no gas generation in any hour, resulting in a 100% zero-carbon generation level.

The SSP H2 case has a similar generation mix as the SPP case (since the Texas portion of the system is held separate and unaffected) but H2 capacity (and a need for a small amount of H2 energy production) allows the New Mexico portion of the system to reach 100% zero-carbon despite a lower amount of solar output.

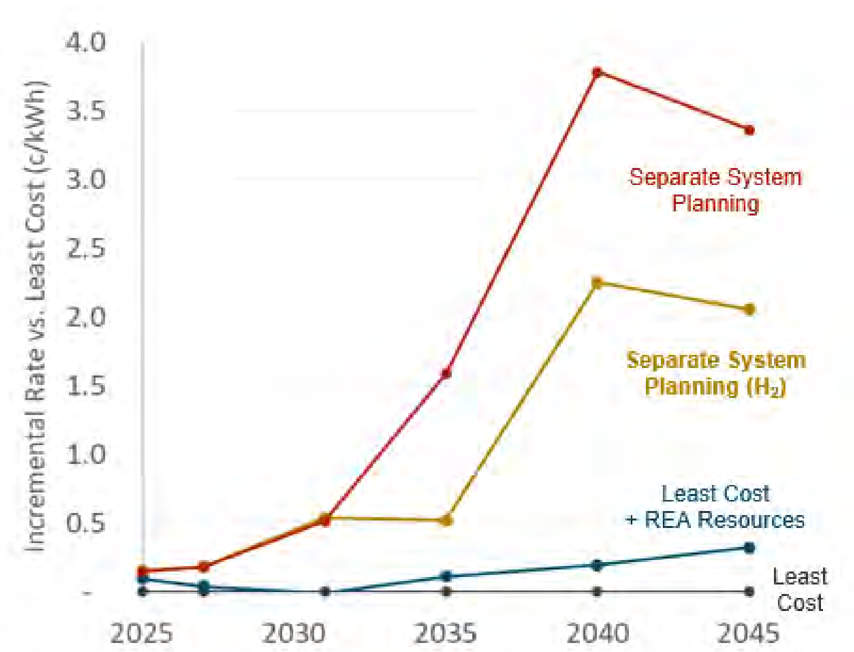
6.4.3 Cost

See Figure 6-10 for the cost impact by year for each of the REA cases evaluated. This chart focuses on the impact to El Paso Electric's New Mexico customers. All cost impacts are calculated based on the difference in annual cost for New Mexico customers relative to the Least-Cost case, divided by the annual New Mexico retail sales (in kWh). This gives an incremental rate impact (in cents/kWh) for New Mexico customers.

The Least-Cost portfolio is, by definition, shown with zero incremental cost in all years. Notably, however, the LC+REA case has only a small incremental cost impact (less than 0.2 cents per kWh in 2040) compared with the Least-Cost case. This result indicates that the LC+REA approach would allow El Paso Electric to increase the share of zero-carbon resources for New Mexico from approximately 70% in the Least-Cost case to 89% in 2030 and 100% in 2040, with a relatively minor impact on total costs.

By contrast, the SSP case is the most expensive case modeled. Its incremental cost for New Mexico customers compared to the Least-Cost case starts at small amounts in the 2020s but rises to 0.5 cents per kWh in 2030, and to over 3.5 cents per kWh by 2040. In this case, the significant additional storage and solar required to ensure reliability without capacity pooling and without any gas generation in any hour results in a significant increase in costs. Adding the option to burn green hydrogen in the SSP H2 case substantially moderates the cost increase compared to SSP case after 2030, but the SSP H2 case is still higher in cost than the LC+REA case, despite providing a similar share of energy from zero carbon resources.

Figure 6-10. New Mexico Customer Rate Impact (Relative to Least-Cost Case)

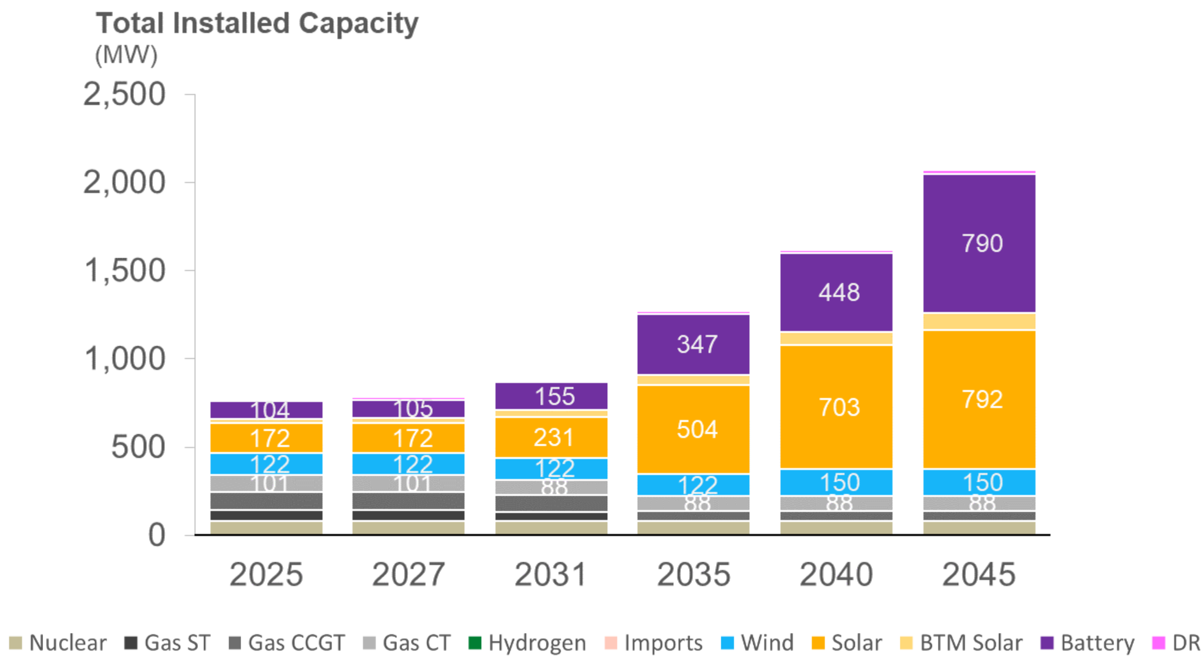


6.5 Least-Cost + REA Detailed Results

This section presents the year-by-year results for New Mexico in the Least-Cost + REA Resources case. This case adds incremental resources that are dedicated to the New Mexico jurisdiction while limiting cost impacts considerably compared with the Separate System Planning case.

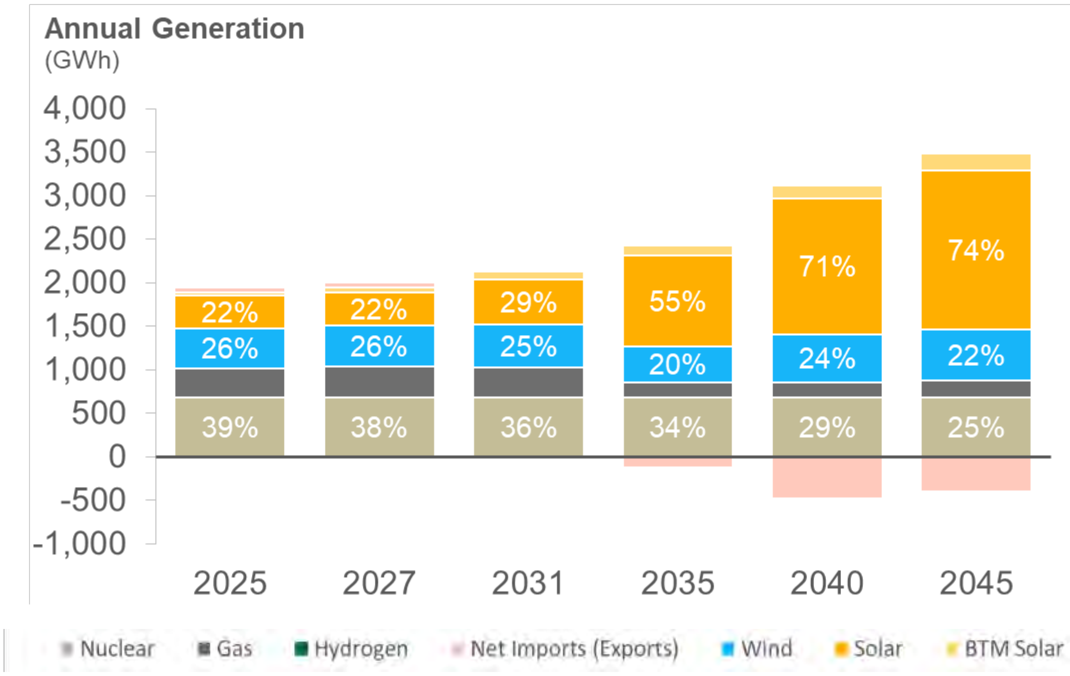
See Figure 6-11 for the total capacity for the New Mexico jurisdiction through 2045. No additional gas capacity is allocated to the New Mexico jurisdiction, and the amount of gas capacity declines as units retire. In 2025, more than 100 MW each of solar, storage, and wind capacity is dedicated to the New Mexico jurisdiction. The capacity for each of these resources grows through 2045, with solar and storage accounting for most capacity additions.

Figure 6-11. Capacity for NM Jurisdiction in LC+REA Case



See Figure 6-12 for the annual generation for the New Mexico jurisdiction through 2045. The figure shows the amount of renewable generation as a proportion of retail sales in all years. As the amount of renewable generation increases, the share of gas generation declines. In 2040 and 2045, when the 100% zero-carbon energy requirement is imposed in this case, there is still some gas generation. This gas generation helps satisfy load in some hours, while additional renewable generation in other hours exceeds New Mexico load and more than offsets this gas generation.

Figure 6-12. Annual Generation for NM Jurisdiction in LC+REA Case[40]



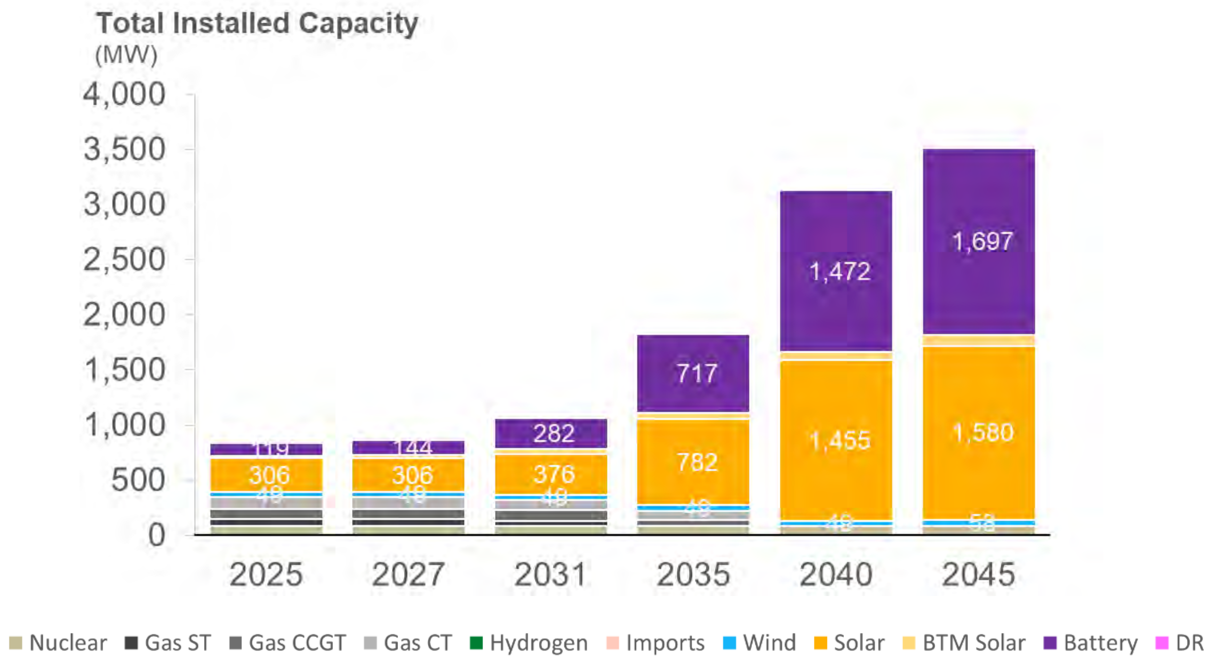
6.6 Separate System Planning Detailed Results

This section presents the year-by-year results for New Mexico in the Separate System Planning (SSP) case. This case adds significantly more resources dedicated to the New Mexico jurisdiction than the LC+REA case. These resource additions are necessary to allow New Mexico to balance energy supply and demand on an hourly basis without relying on gas resources or imports during any hour in 2040 and beyond.

See Figure 6-13 for the total capacity for the New Mexico jurisdiction through 2045 in the SSP case. No additional gas capacity is allocated to the New Mexico jurisdiction, and the amount of gas capacity declines as units retire. By 2040, the portfolio does not include any gas resources, consistent with the 100% zero-carbon interpretation used in this case. In 2025, more than 300 MW of solar, 100 MW of storage, and 40 MW of wind capacity is allocated to the New Mexico jurisdiction. The capacity for each of these resources grows through 2045, with solar and storage accounting for most capacity additions. In 2040 and 2045, the total solar and storage capacity levels are more than double the amounts in the LC+REA case.

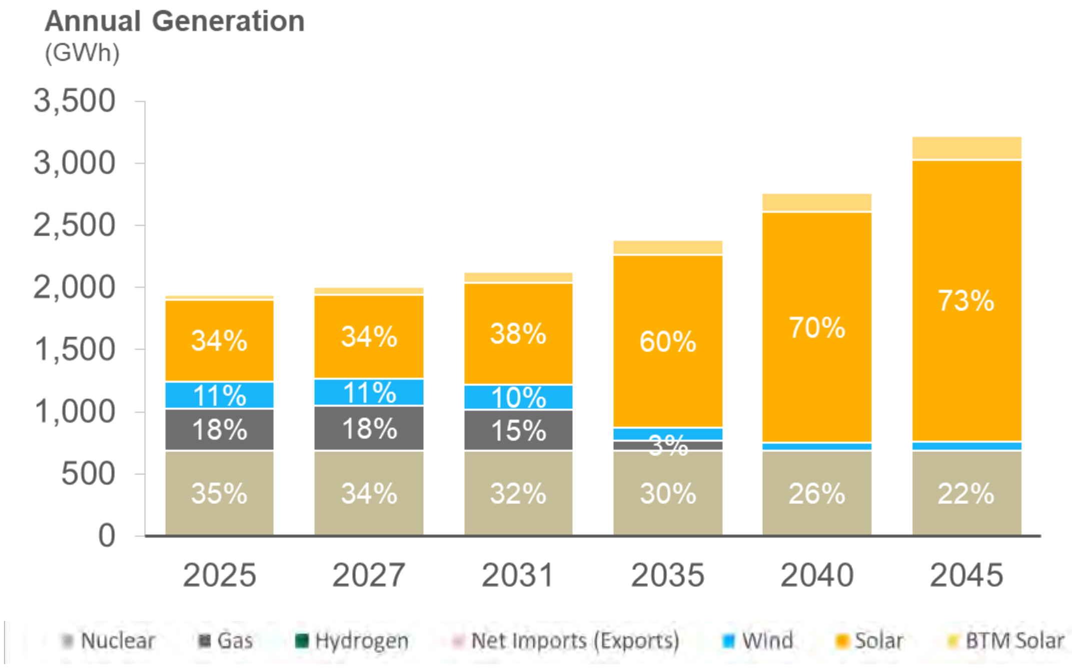
[40] The chart shows percentages for renewable and nuclear generation. This is the generation expressed as a percentage of retail sales for the New Mexico jurisdiction.

Figure 6-13. Capacity for NM Jurisdiction in SSP Case



See Figure 6-14 for the annual generation for the New Mexico jurisdiction through 2045 in the SSP case. As the amount of renewable generation increases, the share of gas generation declines. By 2040, only renewable and zero-carbon resources supply energy to New Mexico customers, with utility-scale solar accounting for 70% of the total generation. Curtailment is expected given the significant renewable additions in this case, especially during spring months. The amount of energy that is curtailed from renewables each hour is assumed to be spread evenly across the renewable resources operating during those hours, which leads to the decreasing percentage of wind shown but does not reflect an actual decline in the total available wind generation. Which renewable resources get curtailed during real-world operations may differ from what is assumed in this study, but this does not impact other system dynamics.

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



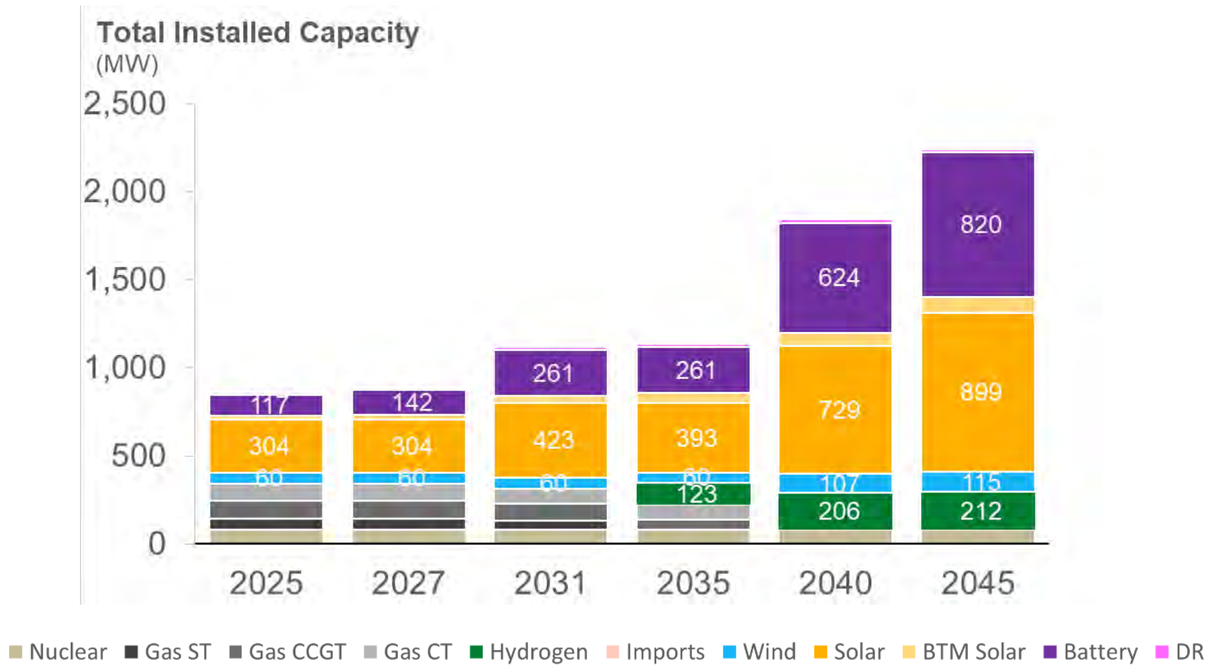
6.7 Separate System Planning (H2) Detailed Results

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.

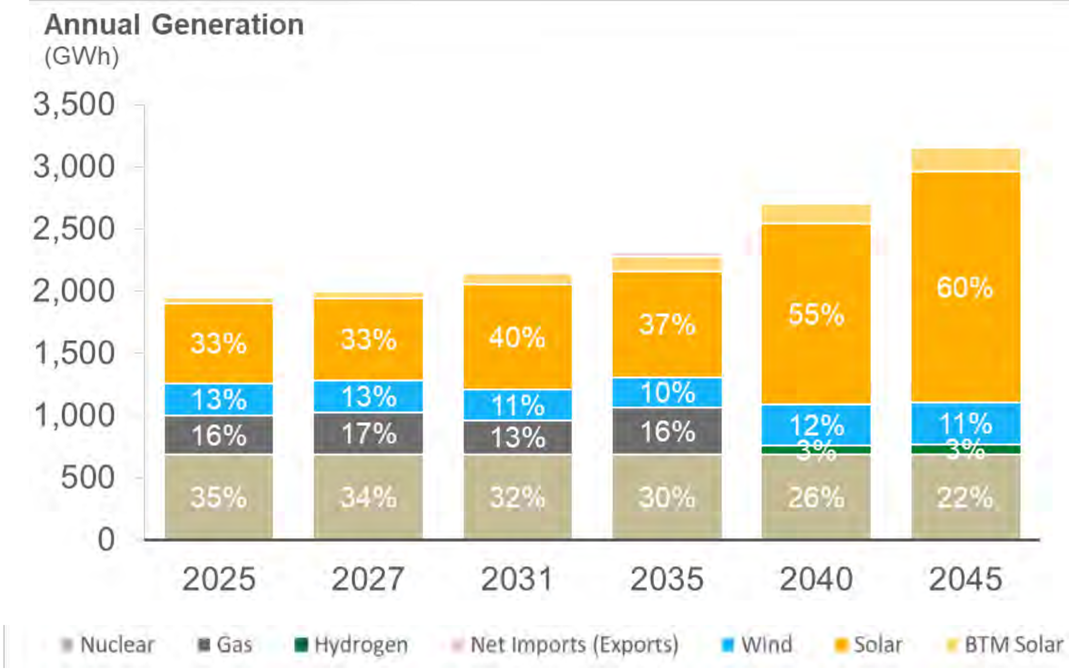
[41] The chart shows percentages for solar, wind, natural gas, and nuclear. This is the generation expressed as a percentage of total New Mexico load.

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

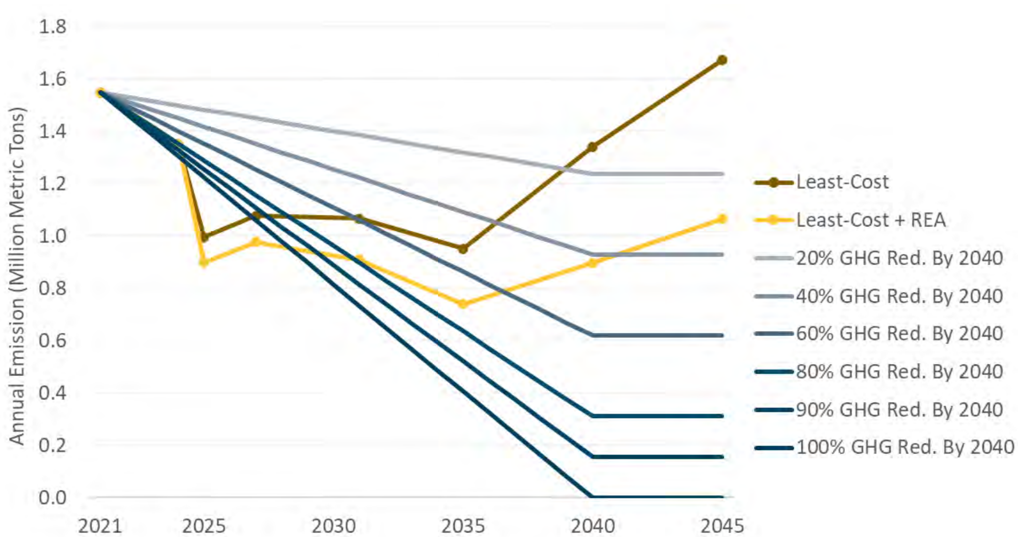
In addition to the REA cases, E3 performed analysis on several sensitivity cases to evaluate uncertainties in key planning assumptions and their impacts on the system portfolio. For each sensitivity case, E3 varied one or more inputs from the Least-Cost case and reoptimized for the period 2025-2045 to 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



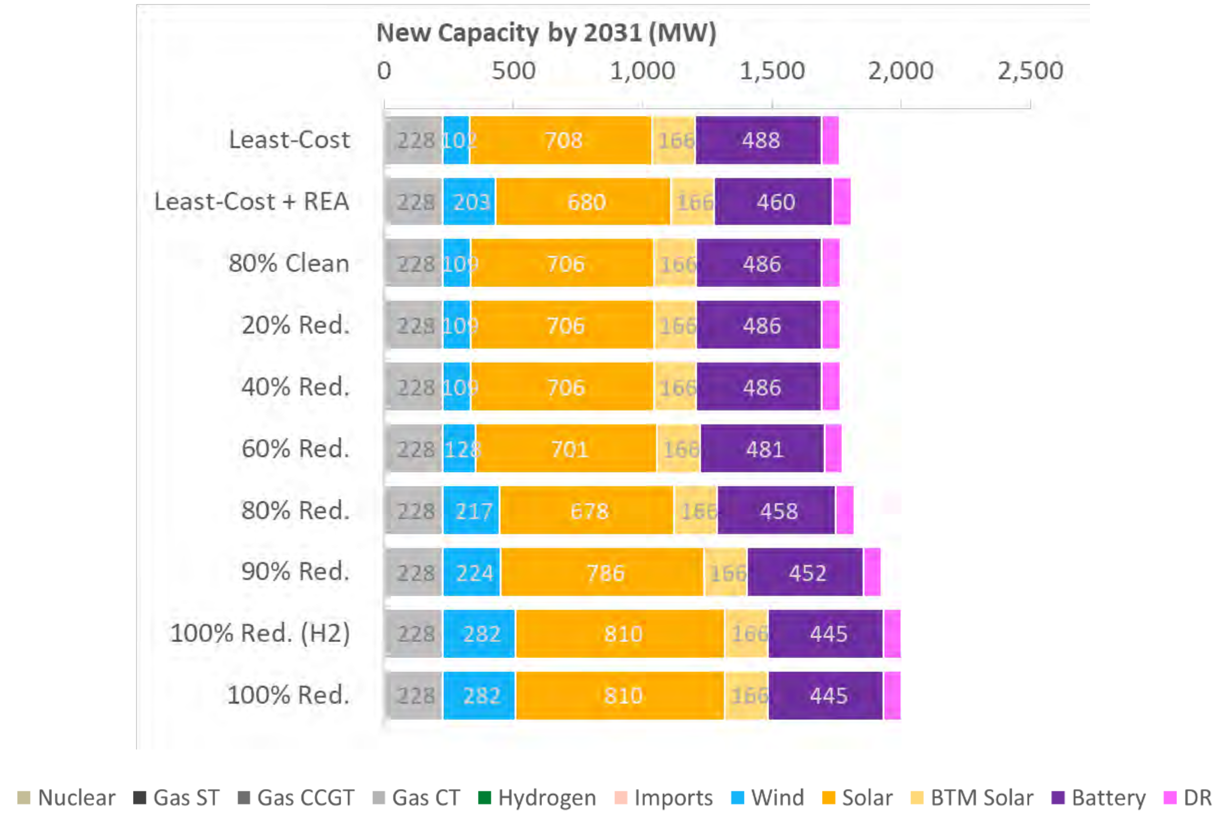
Modeling a range of carbon reduction trajectories serves two primary purposes. First, it helps inform how the cost of the EPE portfolio changes as a function of greenhouse reduction levels. This cost-carbon relationship can help guide future portfolio decisions. Second, there is a possibility that the 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.

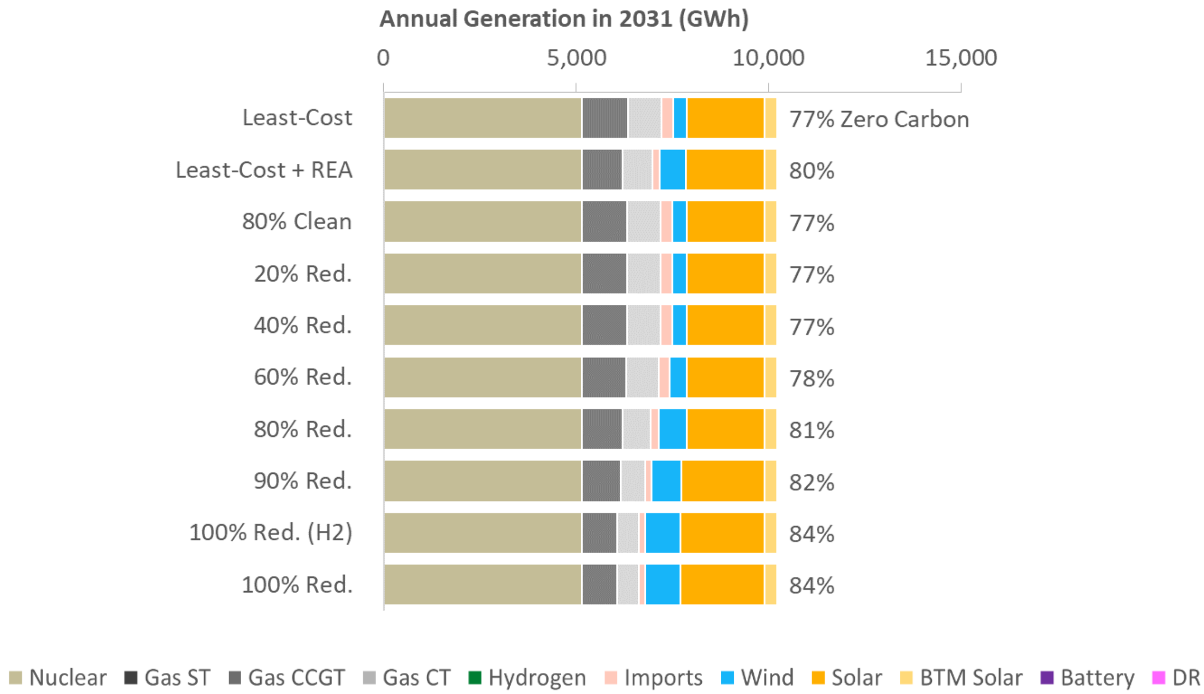
[43] E3 presented draft results for the carbon reduction sensitivities at the 2021 El Paso Electric Company Integrated Resource Plan Public Participation March 2021 Meeting. This report provides final results for the carbon reduction sensitivities.

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

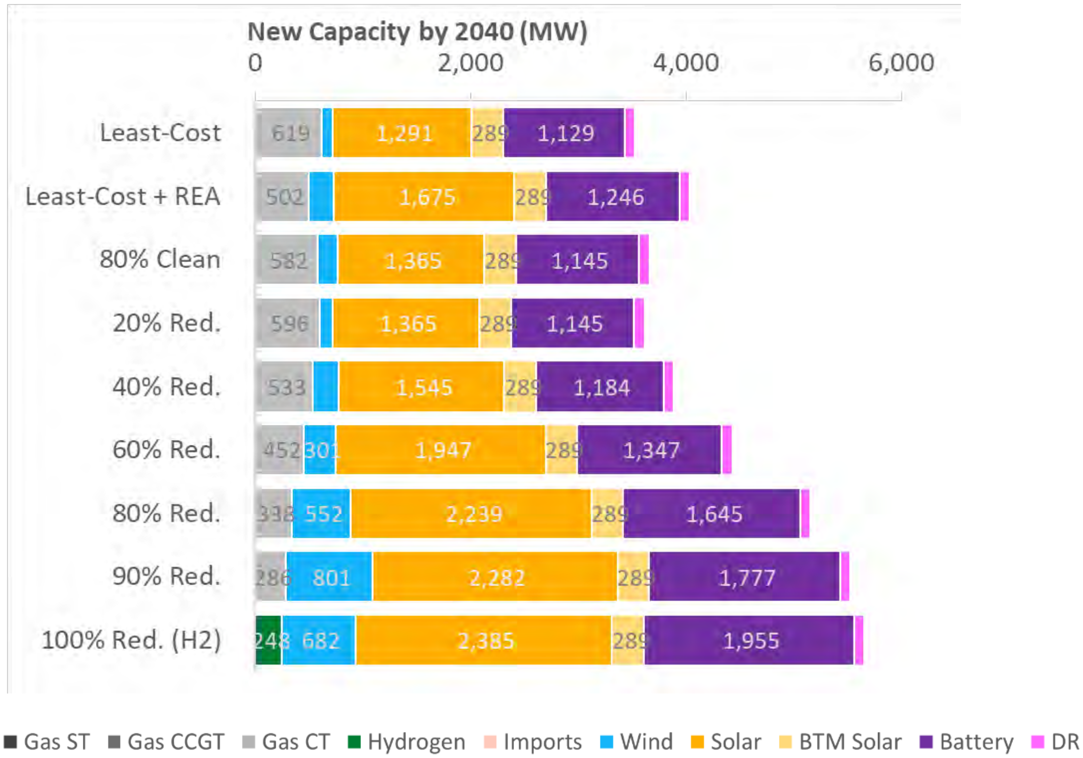
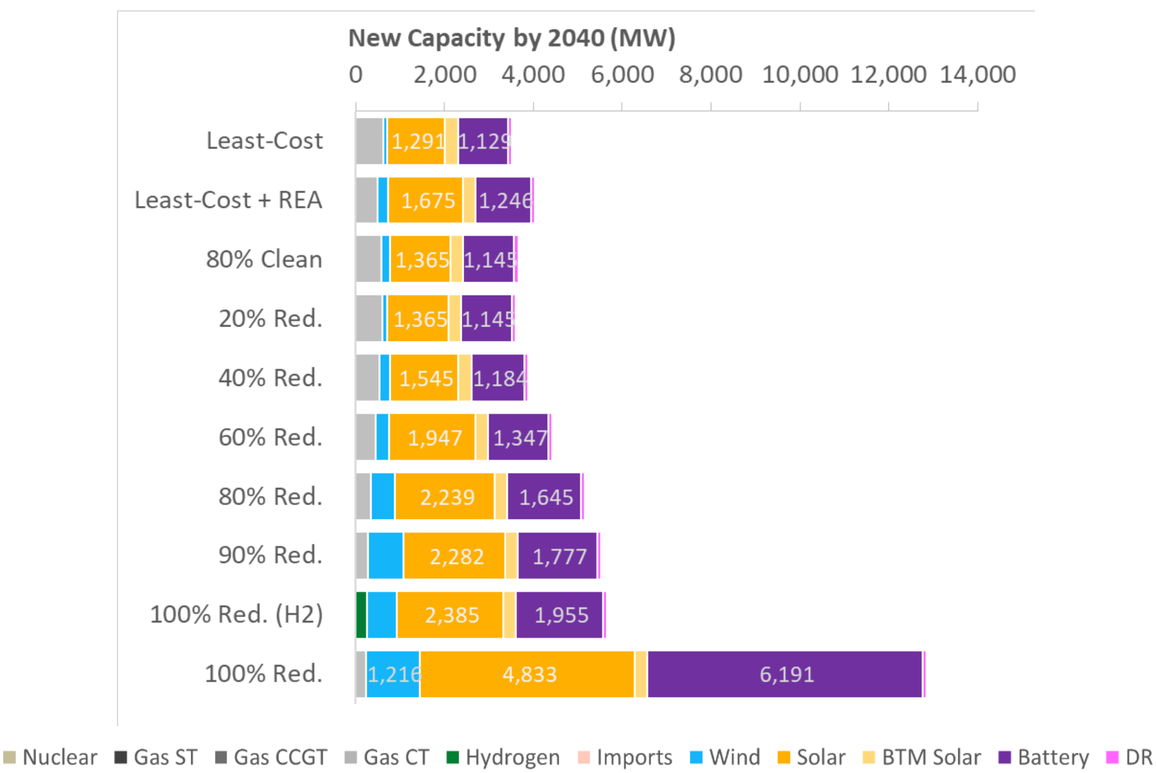
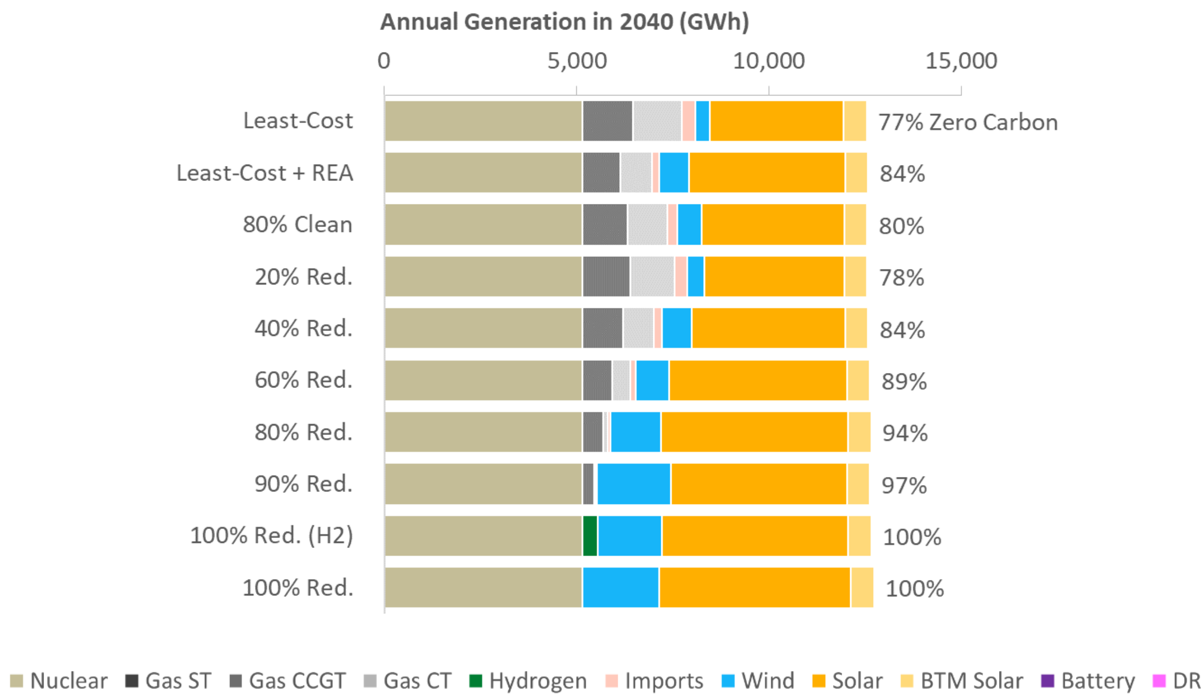


Figure 7-5. Cumulative New Capacity by 2040 for Carbon Reduction Sensitivities



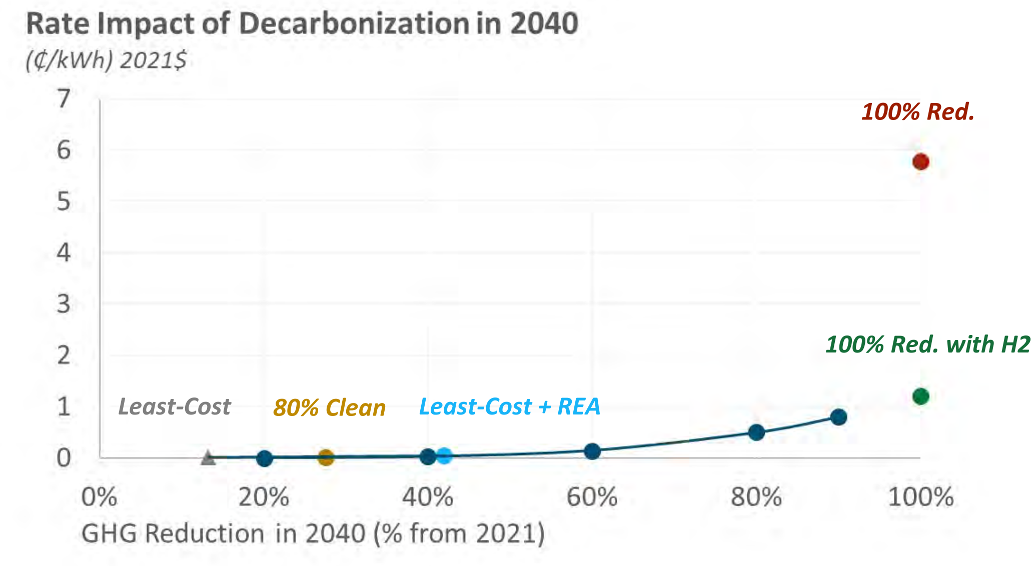
See Figure 7-6 for the annual generation mix in 2040 across carbon reduction sensitivities. Gas generation and market imports decline as the stringency of the targets increases. In the 100% Carbon Reduction (H_2) case, nuclear, wind, and solar resources make up most of the energy supply. Given the high 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

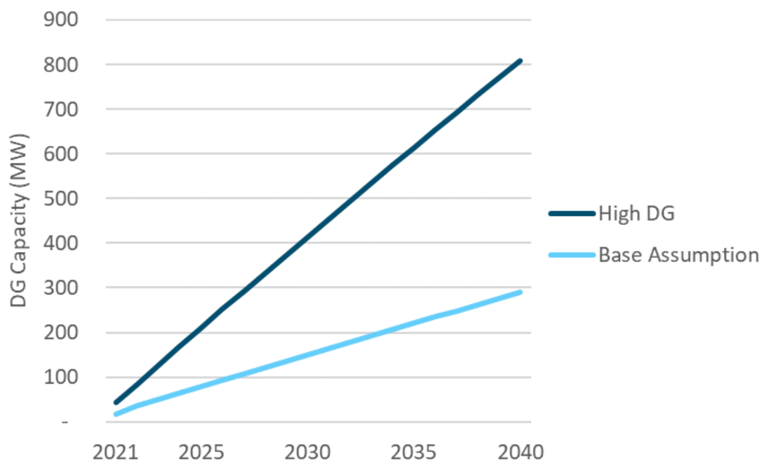
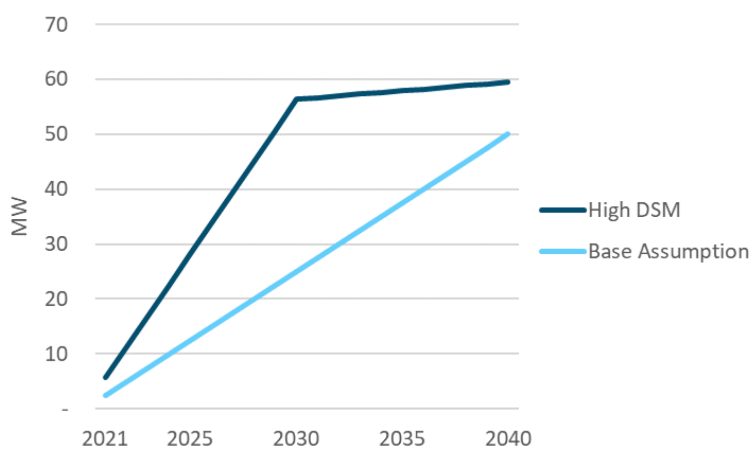


Figure 7-9. Smart Thermostat Capacity in the High DSM Sensitivity



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

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

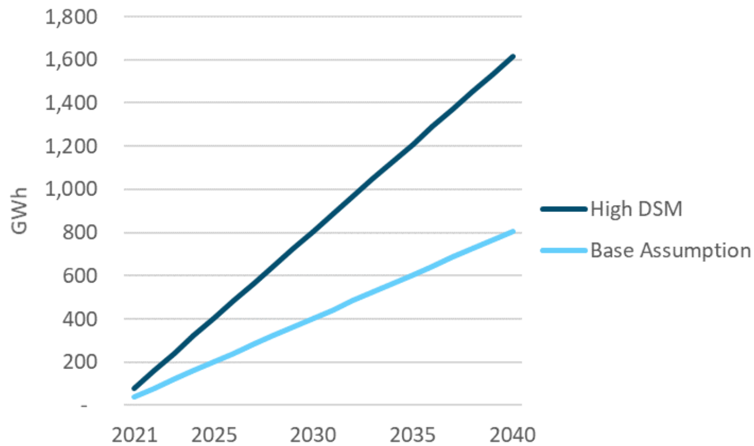
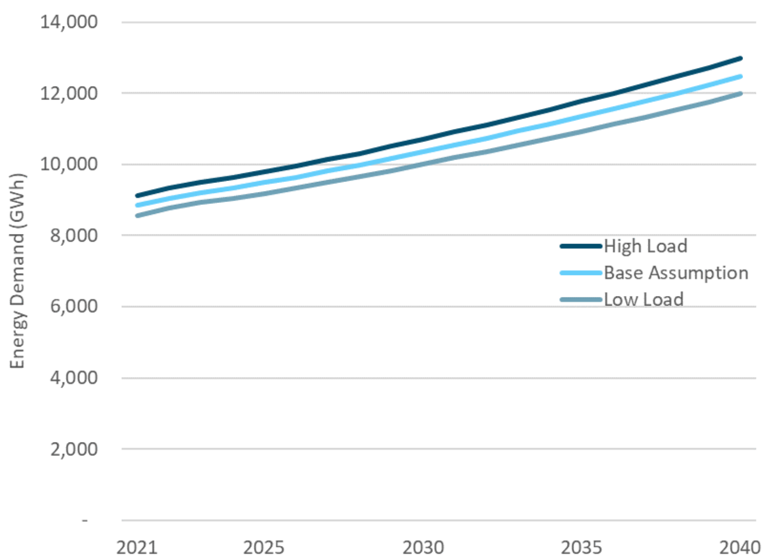


Figure 7-11. Native System Load Forecast[45] for Energy in Load Sensitivities



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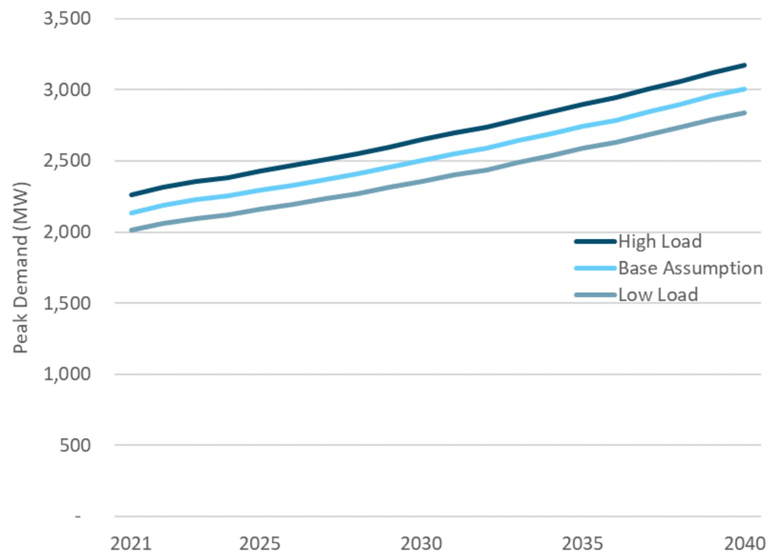
[45] Native system forecast does not include the impact of energy efficiency (EE), distributed generation (DG), and electric vehicles (EV). These components are accounted for separately and do not change in the Low Load or High Load sensitivities.

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

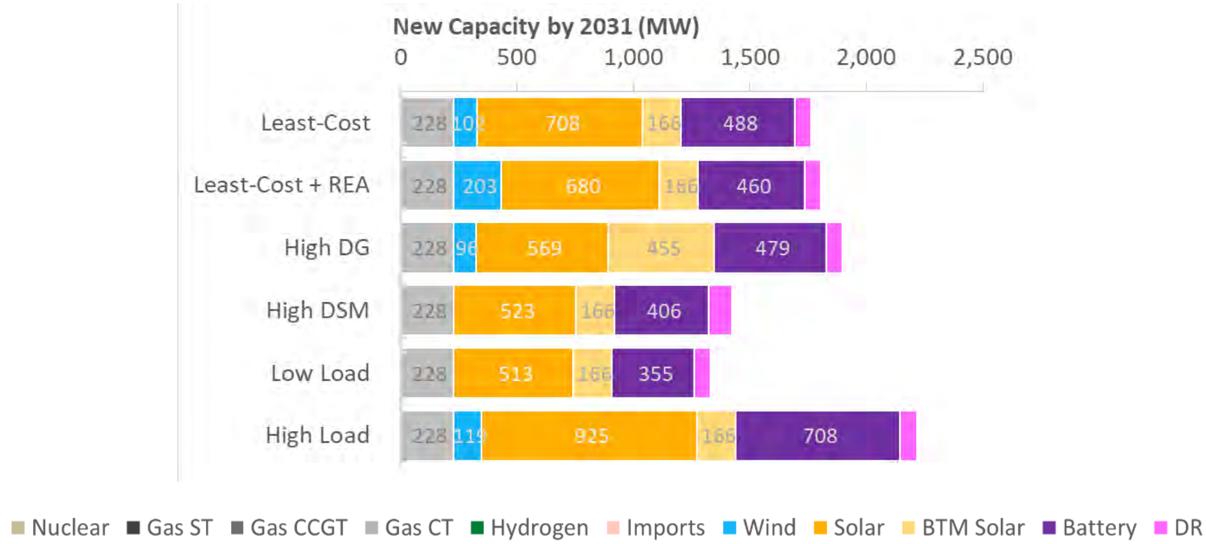


Figure 7-14. Cumulative New Capacity by 2040 for Load and Demand-Side Resource Sensitivities

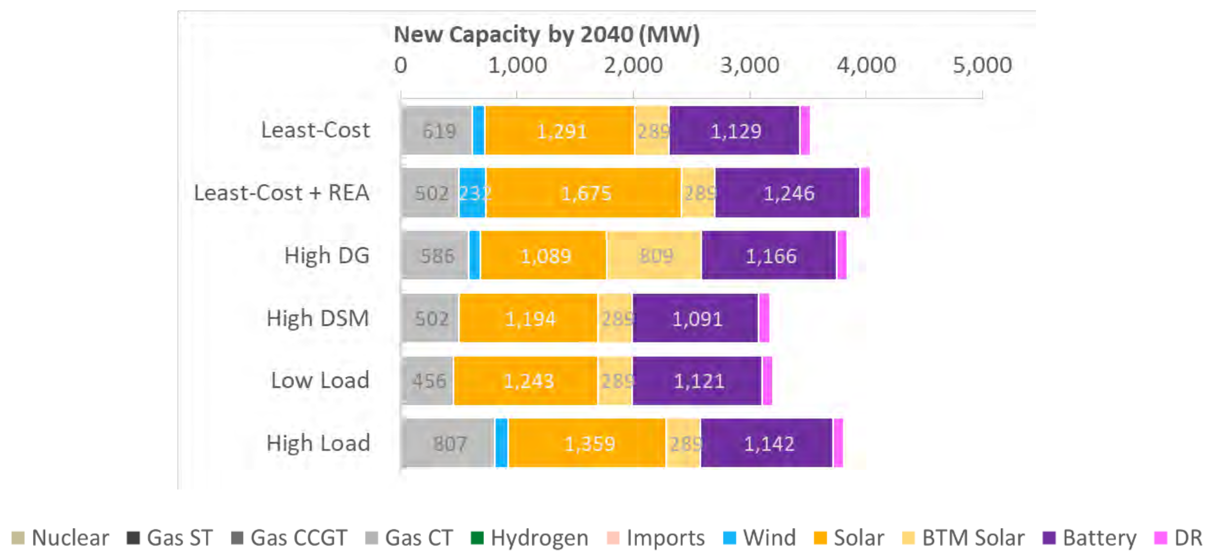


Figure 7-15. Annual Generation in 2031 for Load and Demand-Side Resource Sensitivities

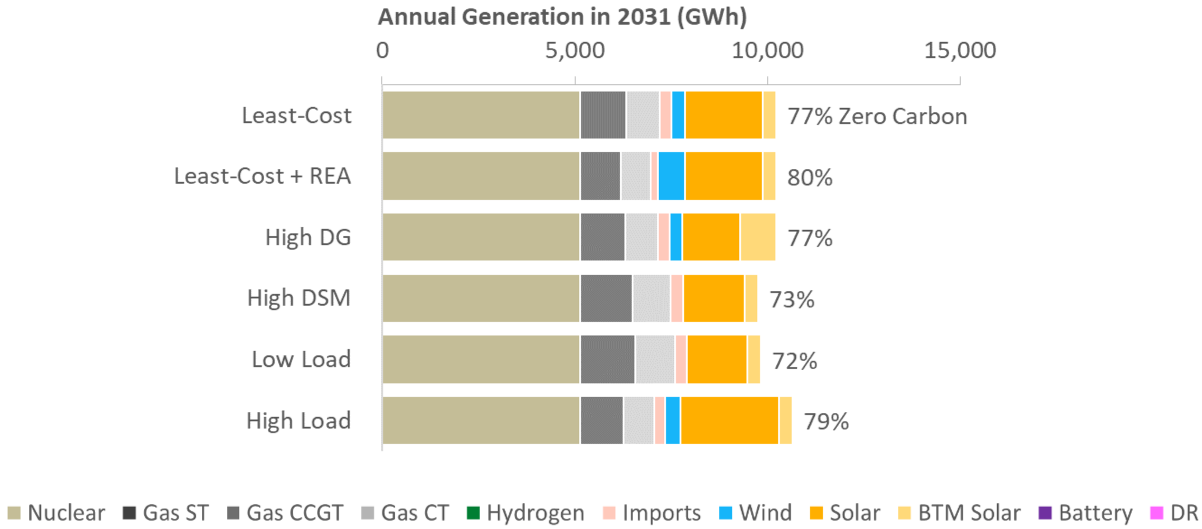
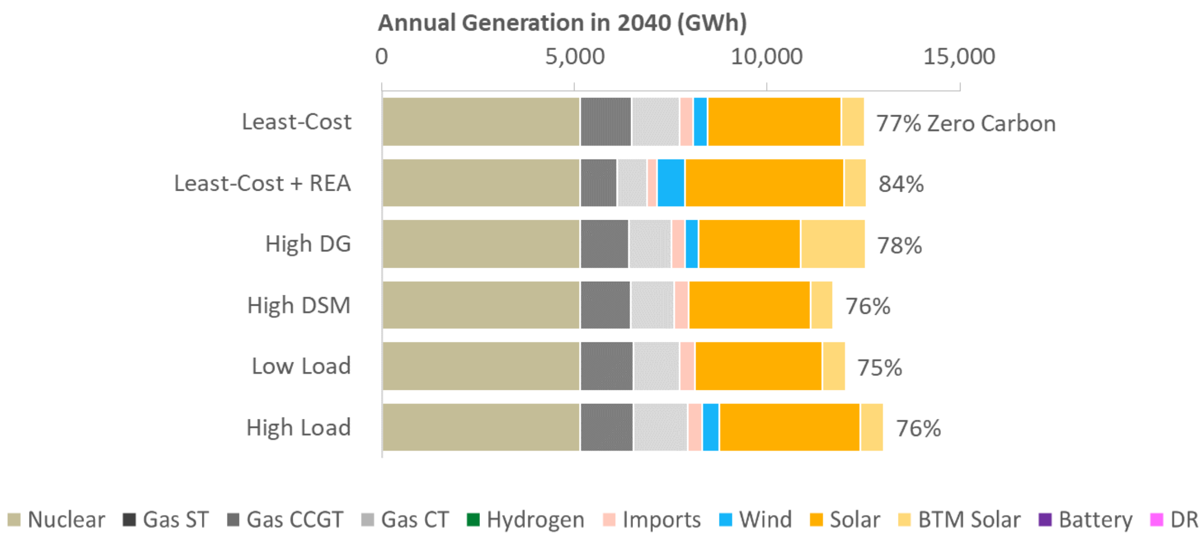


Figure 7-16. Annual Generation in 2040 for Load and Demand-Side Resource Sensitivities



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

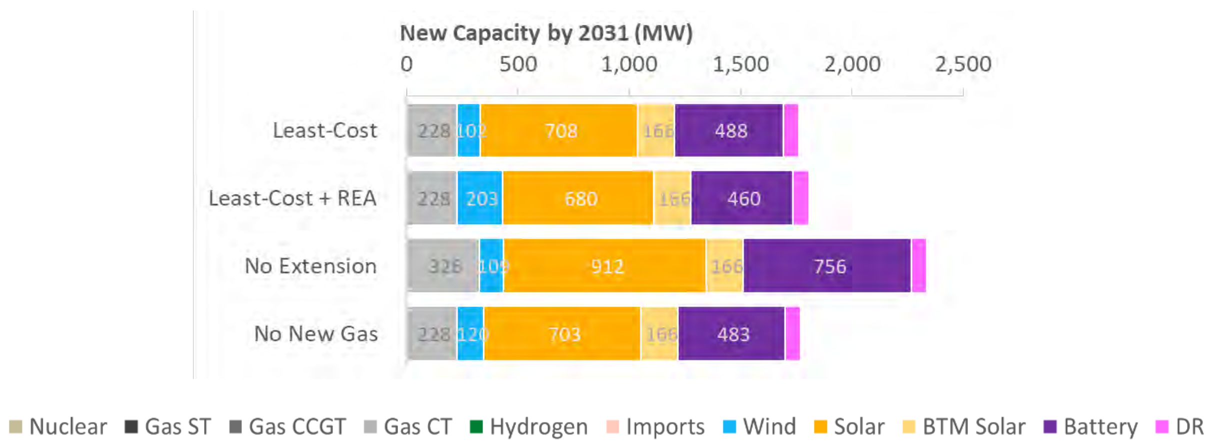
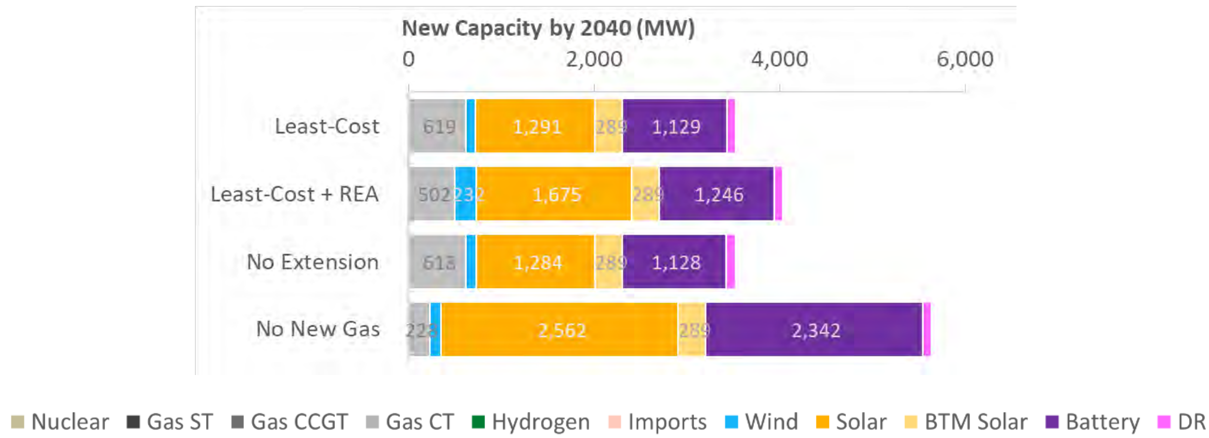


Figure 7-18. Cumulative New Capacity by 2040 for Gas Resource Sensitivities



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

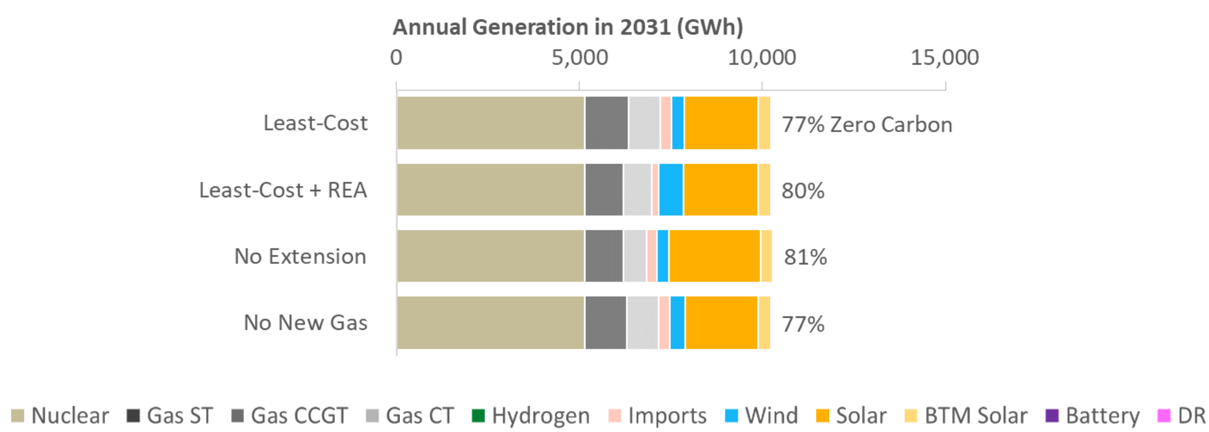
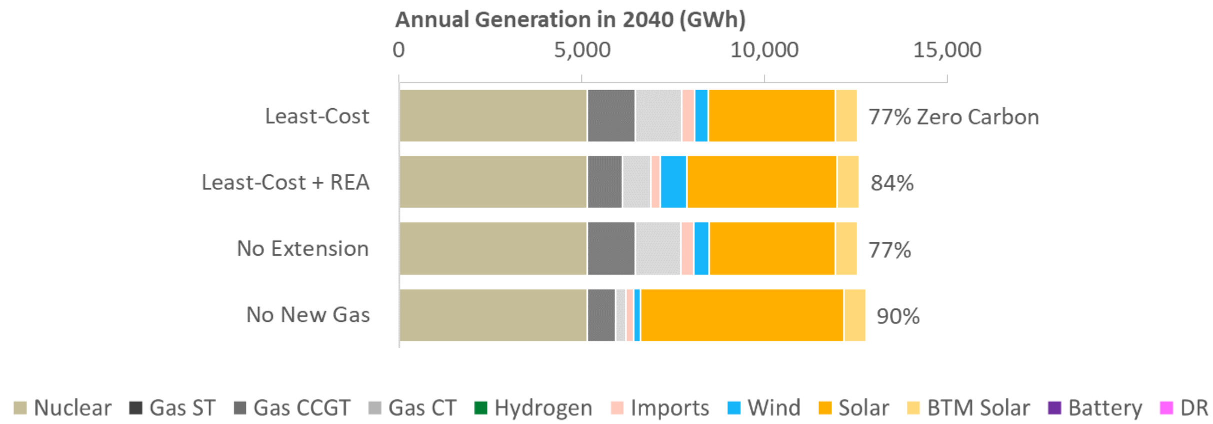
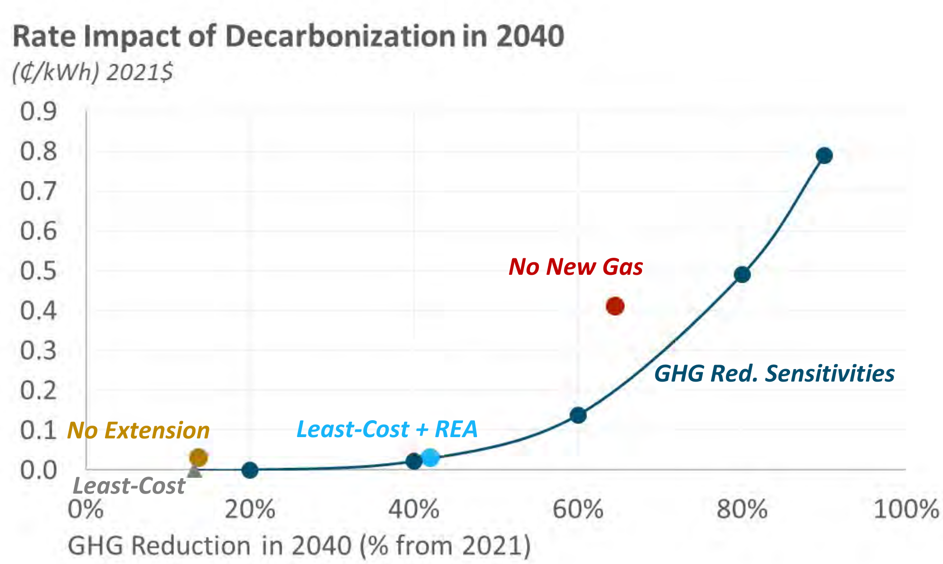


Figure 7-20. Annual Generation in 2040 for Gas Resource Sensitivities



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



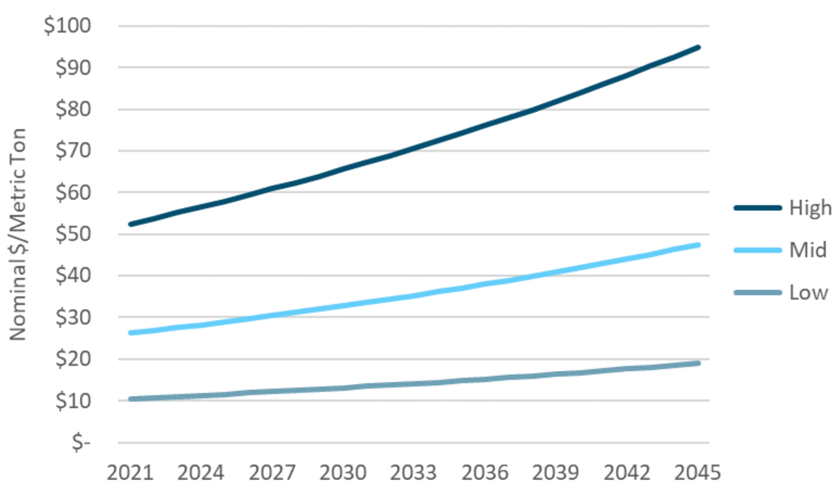
7.4 Gas and Carbon Price Sensitivities

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

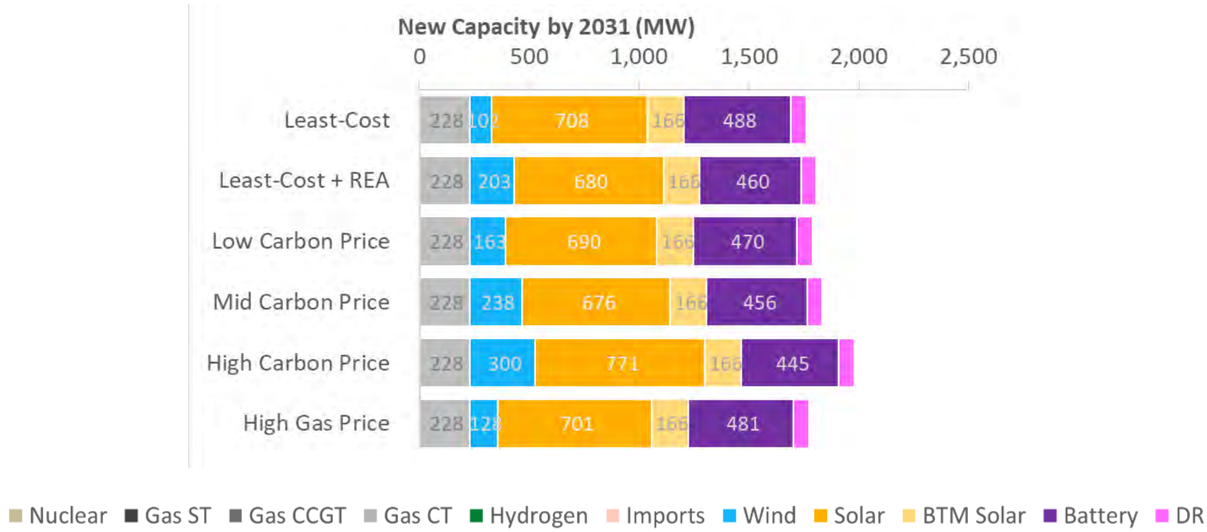


Figure 7-24. Cumulative New Capacity by 2040 for Gas and Carbon Price Sensitivities

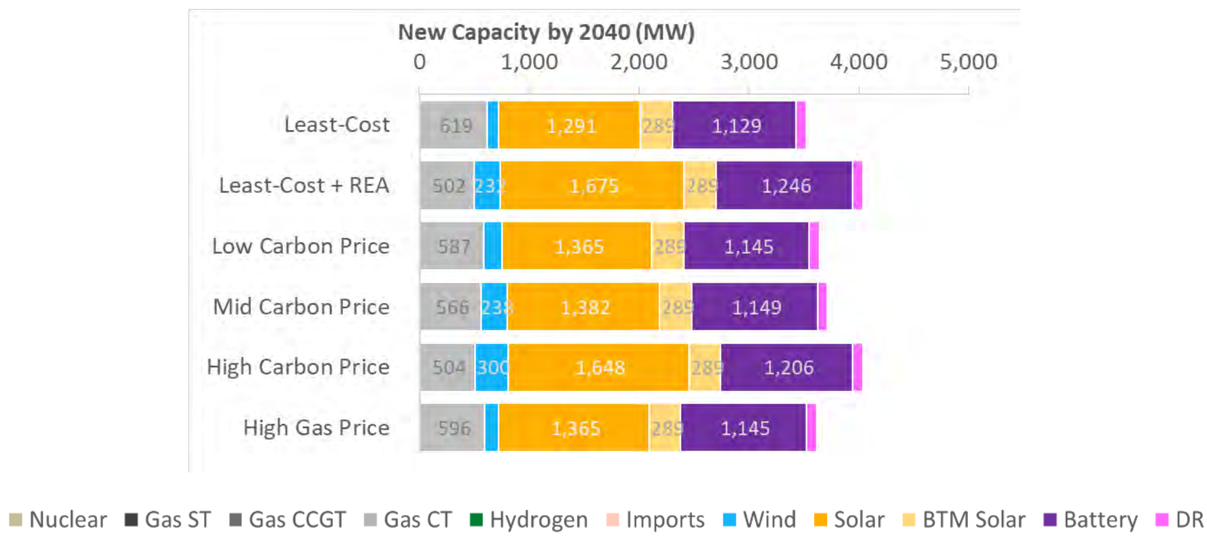


Figure 7-25. Annual Generation in 2031 for Gas and Carbon Price Sensitivities

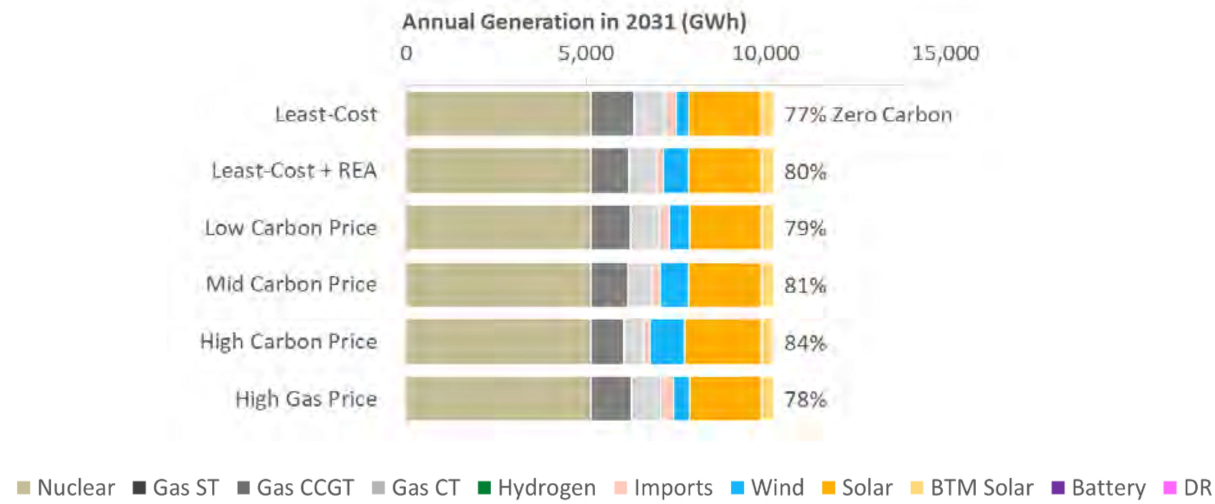
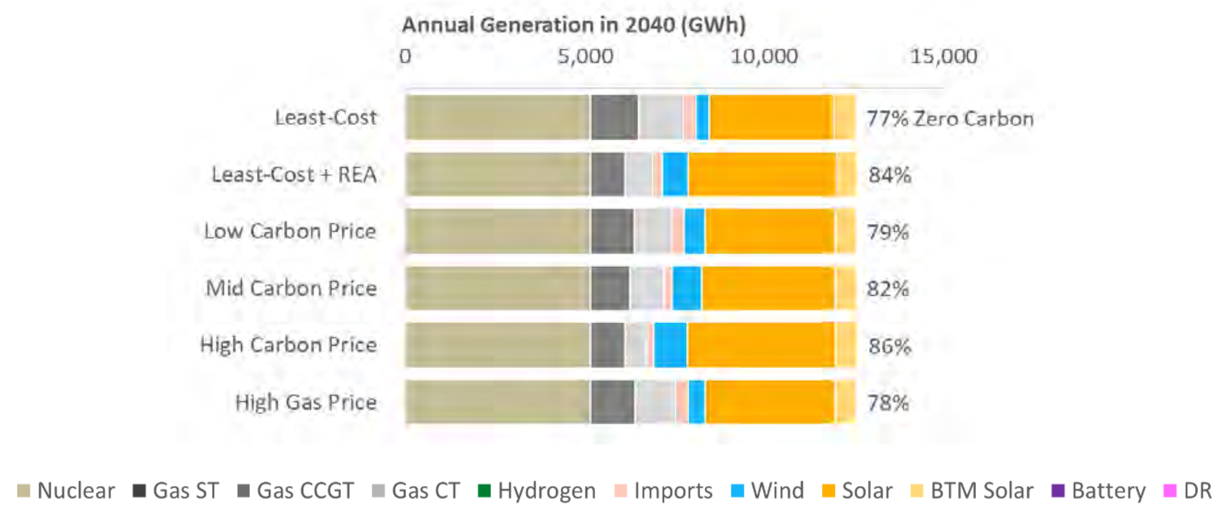


Figure 7-26. Annual Generation in 2040 for Gas and Carbon Price Sensitivities



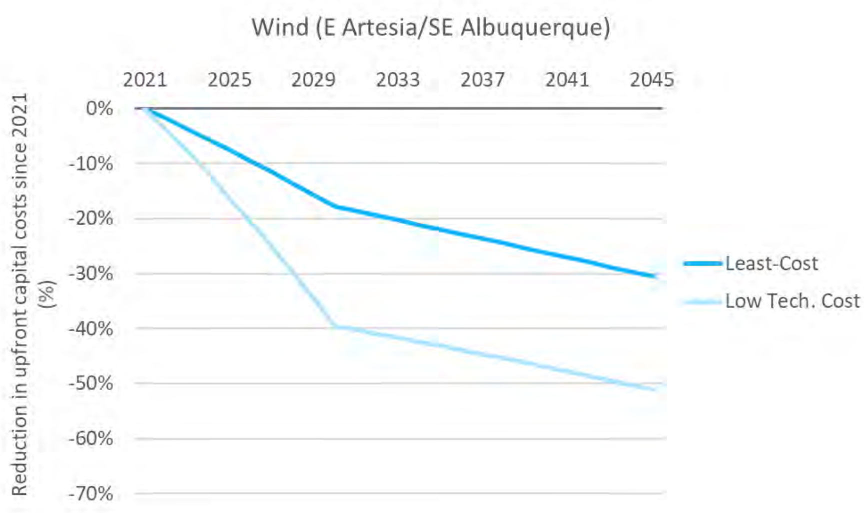
7.5 Technology Cost Sensitivity

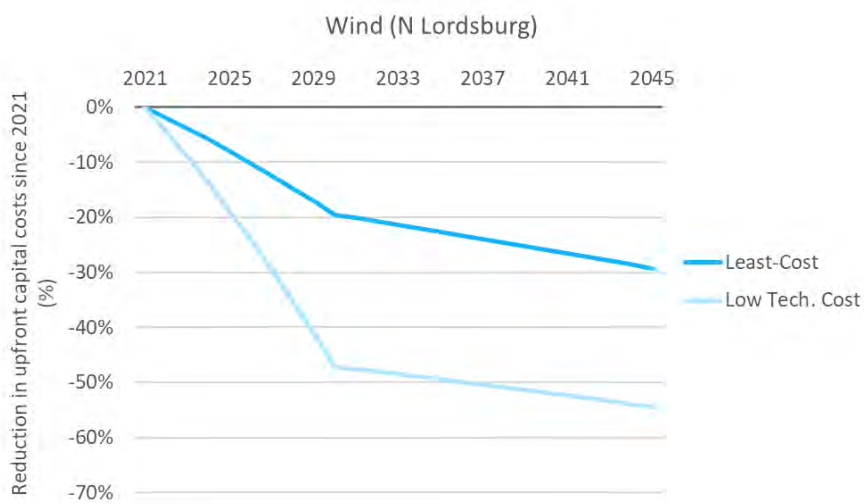
The deployment levels of different technologies within an optimal portfolio depend on many factors, but one of the most important is the cost of the technology. In recent years, the cost of renewable and storage resources has fallen dramatically. Under base assumptions, there are substantial further 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.

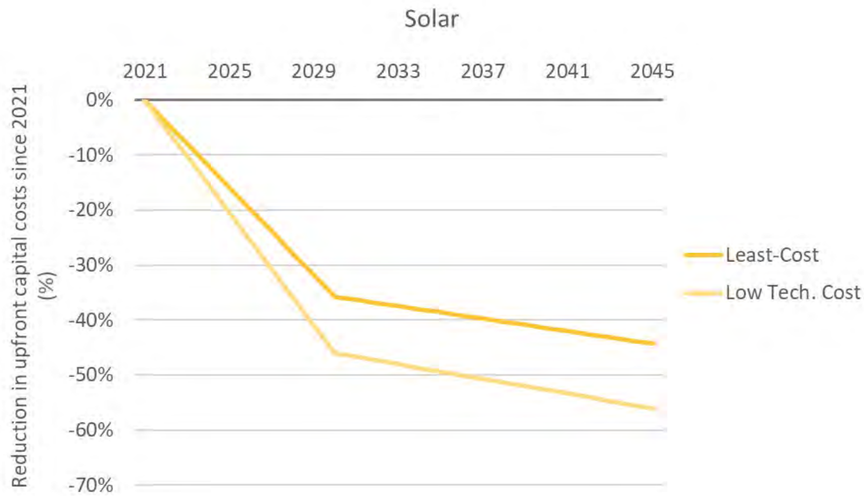
storage costs declining more quickly than under the base assumptions.[48] Figure 7-27 shows the change in resources costs by technology.

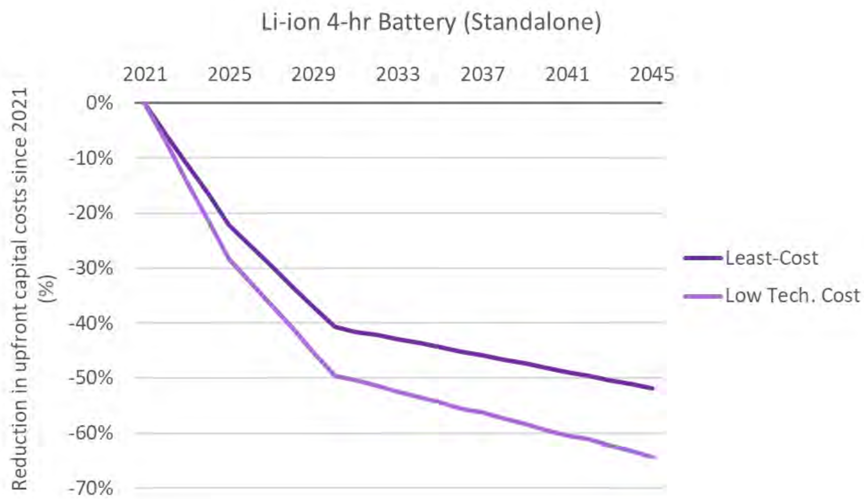
Figure 7-27. Cost Reductions in the Low Technology Cost Sensitivity





[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

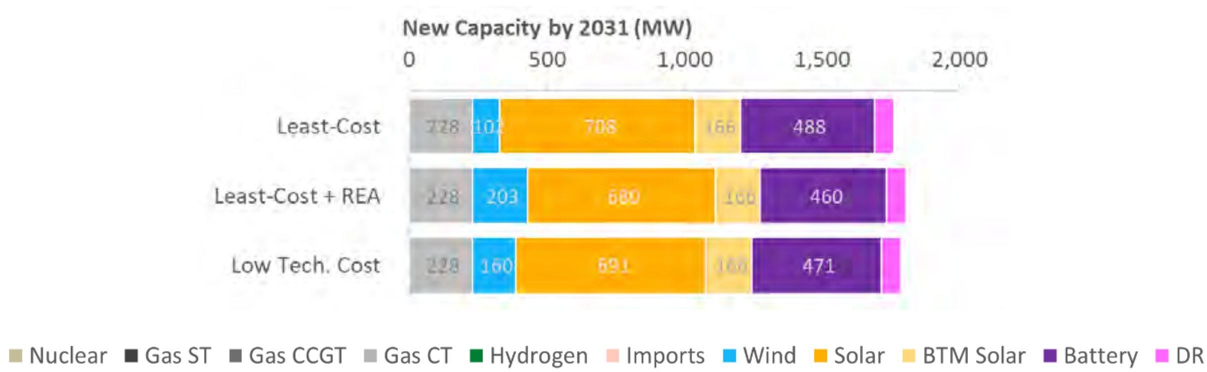


Figure 7-29. Cumulative New Capacity by 2040 for Low Technology Cost Sensitivity

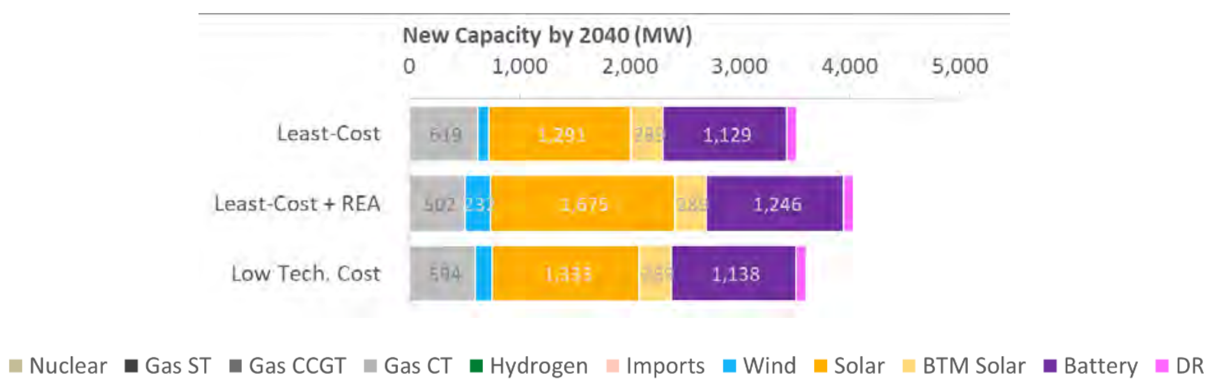


Figure 7-30. Annual Generation in 2031 for Low Technology Cost Sensitivity

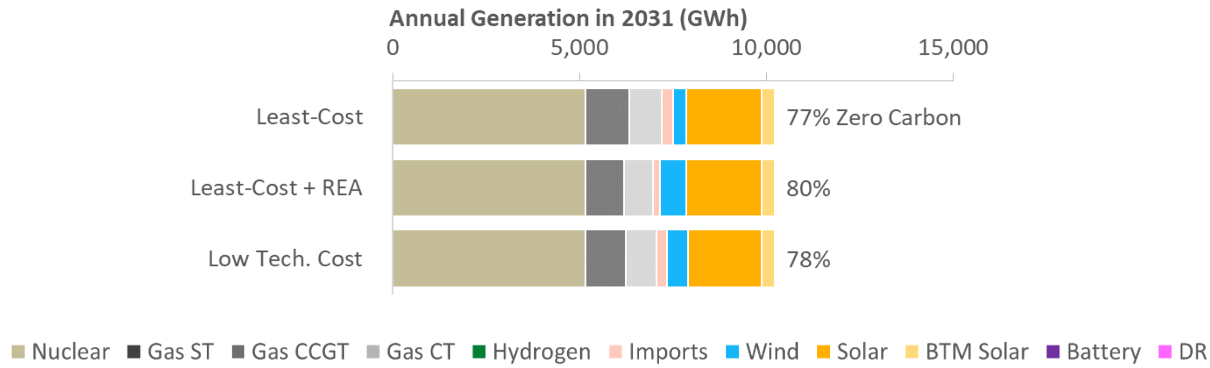
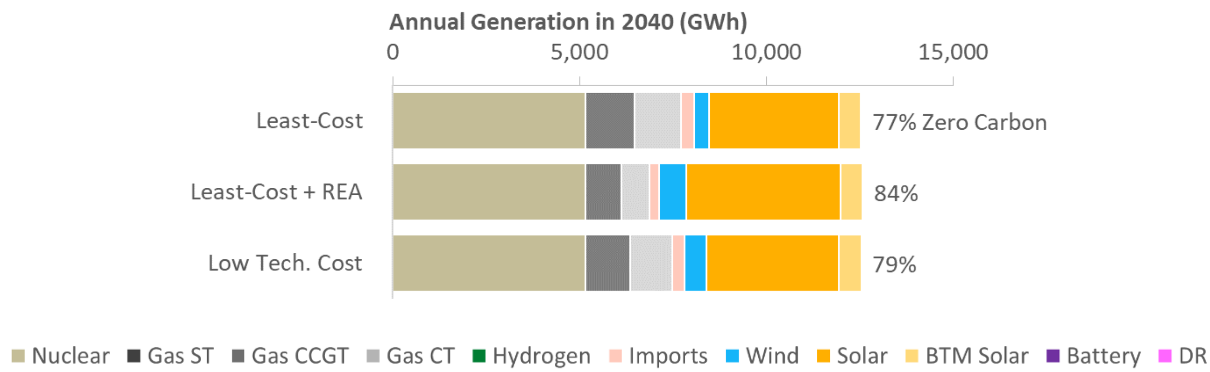


Figure 7-31. Annual Generation in 2040 for Low Technology Cost Sensitivity



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.

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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 $)

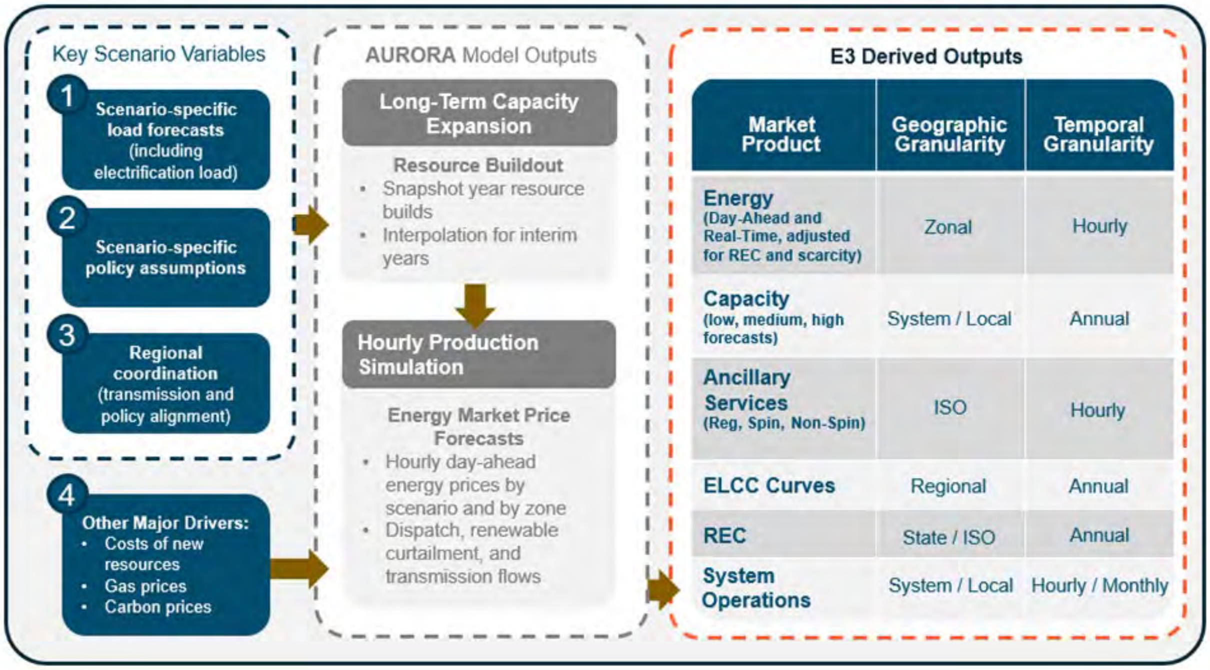
Year	GasInter	NewInter	GasIntra	Uranium	Biomass	Hydrogen
2021	2.84	2.76	2.89	0.71	3.18	27.61
2022	2.48	2.41	2.53	0.71	3.18	26.76
2023	2.52	2.45	2.56	0.71	3.18	25.92
2024	2.58	2.51	2.63	0.71	3.18	25.07
2025	2.67	2.59	2.71	0.71	3.18	24.23
2026	2.74	2.65	2.77	0.71	3.18	23.95
2027	2.85	2.76	2.88	0.72	3.18	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

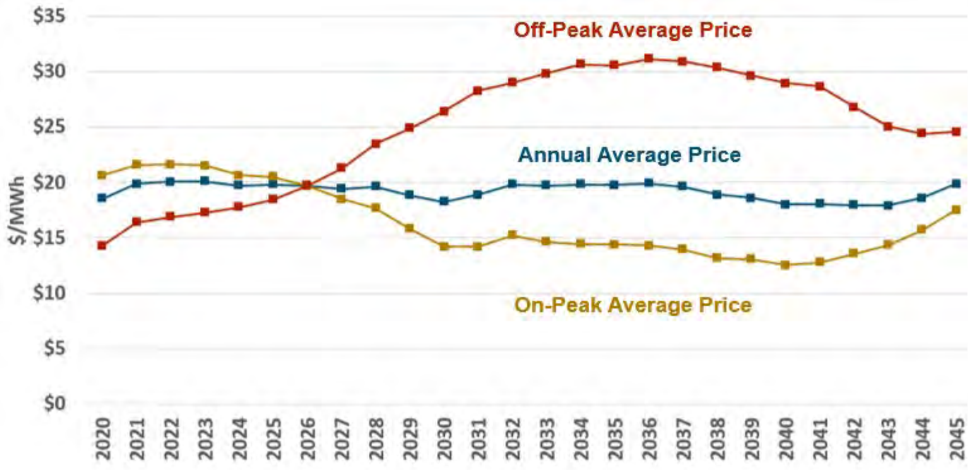
+ **Production Cost Simulation** – simulate day-ahead, zonal energy prices using the Aurora software for each forecast year (2020-2050) and each scenario. Production cost simulation is at the core of E3's 'fundamentals-driven' approach to energy price forecasting because it captures how changes in resources 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 $)



Attachment E-1: Proof of Notice

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

RULE 17.7.3 NMAC FILING

EL PASO ELECTRIC COMPANY
NOTICE OF 2021 INTEGRATED RESOURCE PLAN

2020-2021 PLANNING PROCESS AND
PUBLIC ADVISORY PROCESS MEETINGS

DECLARATION OF CURTIS HUTCHESON OF NOTICE TO CUSTOMERS

I ***Curtis Hutcheson***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed as *Supervisor-Regulatory Case Management*. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

3. My responsibilities include the oversight and preparation of rate and regulatory filings and compliance with the various regulatory requirements of the jurisdictions in which EPE operates.

4. Pursuant to Rule 17.7.3.9H(1) NMAC, the New Mexico Public Regulation Commission ("Commission") requires EPE to provide notice of EPE's 2021 Integrated Resource Plan's 2020-2021 Planning Process and Public Advisory Process Meetings in the utility's billing inserts.

5. EPE directly mailed the required notice to all existing New Mexico customers in a bill insert between June 4, 2020 and July 2, 2020. A copy of the bill insert is attached as Exhibit A to

this Affirmation.

6. EPE also published the notice in the Las Cruces Sun News on May 31, 2020. The affidavit and tear sheet are attached as Exhibit B to this Affirmation.

7. EPE provided notice on June 4, 2020, 30 days prior to the first scheduled meeting on July 10, 2020, to the commission, interveners in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings. The email of the notice and certificate of service is attached as Exhibit C to this Affirmation.

I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***2021 Integrated Resource Plan's 2020-2021 Planning Process and Public Advisory Process Meetings.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on May 13, 2021.

__/s/ Curtis Hutcheson________

CURTIS HUTCHESON

Attachment E-1: Proof of Notice

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

RULE 17.7.3 NMAC FILING

EL PASO ELECTRIC COMPANY

NOTICE OF 2021 INTEGRATED RESOURCE PLAN

2020-2021 PUBLIC ADVISORY PROCESS MEETINGS

Notice is hereby given that:

El Paso Electric Company ("EPE") invites members of the public to participate in the Integrated Resource Plan (“IRP”) public advisory process through a series of public meetings. With public participation, EPE will develop its IRP pursuant to the New Mexico Efficient Use of Energy Act and the New Mexico Public Regulation Commission's ("Commission") IRP Rule, 17.7.3 NMAC. EPE's IRP is developed to identify cost-effective demand-side and supply-side electricity resources to serve EPE's customers over the next 20-year planning period.

The IRP will be submitted to the Commission no later than July 2021. Public participation is an important component of the development and implementation of EPE's integrated resource planning in New Mexico. EPE encourages interested members of the public to attend these public meetings to provide public input and commentary, whether as a residential or business customer, or as a representative of a trade, non-profit, neighborhood, shareholder, civic or other group.

Given the currently effective limitations on public gatherings in New Mexico and Texas, the first scheduled meeting will be held electronically and by phone conference on July 10, 2020, at 2:00 p.m. MDT. The IRP process will be explained, and additional meeting dates and locations will be set at that time. Prior to each meeting, the presentation for that meeting will be posted on EPE's website, www.epeletric.com. If you are interested in attending the meeting or otherwise participating in the process, please contact EPE by emailing NMIRP@epelectric.com or calling at (915) 543- 4354.

Attachment E-1: Proof of Notice

Las Cruces Sun News
PART OF THE USA TODAY NETWORK

Affidavit of Publication

Ad # 0004190968

This is not an invoice

EL PASO ELECTRIC
POBOX 982

EL PASO, TX 79960

I, a legal clerk of the **Las Cruces Sun News**, a newspaper published daily at the county of Dona Ana, state of New Mexico and of general paid circulation in said county; that the same is a duly qualified newspaper under the laws of the State wherein legal notices and advertisements may be published; that the printed notice attached hereto was published in the regular and entire edition of said newspaper and not in supplement thereof on the date as follows, to wit:

05/31/2020

Despondent further states this newspaper is duly qualified to publish legal notice or advertisements within the meaning of Sec. Chapter 167, Laws of 1937.

Kathleen Allen

Legal Clerk

Subscribed and sworn before me this June 4, 2020:

Nancy Heyrman

State of WI, County of Brown
NOTARY PUBLIC

5·15·23

My commission expires

NANCY HEYRMAN
Notary Public
State of Wisconsin

Ad # 0004190968
PO #: 2021 IRP Notice
\# of Affidavits: 1

This is not an invoice

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION
RULE 17.7.3 NMAC FILING
EL PASO ELECTRIC COMPANY
NOTICE OF 2021 INTEGRATED RESOURCE PLAN
2020-2021 PUBLIC ADVISORY PROCESS MEETINGS

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#4190968, Sun-News, May 31, 2020

Exhibit B
Page 2 of 2

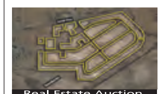
Classifieds

Attachment E-1: Proof of Notice

General

Homes

Business & Service Directory



Legal Notices

Invitation to Bid

A notice is hereby given that Dona Ana County (DAC) will receive Sealed Bids at the Office of the Dona Ana County Purchasing Department, Room 2-147, 845 N. Motel Blvd, Las Cruces, NM 88007, prior to the appointed hour (local time) for the public openings listed below, at which time the bids will be opened and read aloud in Room 2 132. Specifications for said bid are available at 845 N Motel Blvd, Las Cruces, NM Room 2-130. Any bid received after the closing time will be returned unopened.

DAC 20-0048 Invitation to Bid for Pest Control Services for the Fire Administration Department and other Departments as needed will be accepted until June 30, 2020 @ 2:00 PM (local time).

Request for Proposals/Bids are available at: https://donaanacounty.org/bids

Donald E Bullard
Dona Ana County
Chief Procurement Officer
(575) 525-5927
Pub#4215768
Run: May 31, 2020

AGENDA ITEM for the DOÑA ANA COUNTY BOARD OF COUNTY COMMISSIONERS

The Doña Ana County Board of County Commissioners acting as the Board of Appeals will consider the following Agenda Item at its regular meeting on Tuesday, June 23, 2020 at 9:00 a.m., in the County Commission Chambers of the Doña Ana County Government Center, 845 N. Motel Blvd, Las Cruces, NM

Case# AP20-002: The Appellant, Jeremy Green, is appealing a February 27, 2020, Planning and Zoning Commission (P&Z) decision approving Case #Z19-006, for a Zone Change from D1-L (Low Density Residential - Limited) zone to a C1 (Neighborhood Commercial) zoning district for a proposed 9,100 sq. ft. Dollar General store on a property located on the east side of Doña Ana Rd, south of San Ysidro Rd, adjacent to and north of the Elwood Lateral. The parcel was recorded in the Office of the Doña Ana County Clerk on April 16, 1986 with Instrument #8607059 and can be further identified as Parcel Acct. # R0304971. The Appellant is requesting that the Board of County Commissioners (BOCC) reverse the decision of the P&Z based on the mistakes, omissions, and assumptions of the P&Z and County staff.

#4215574,Sun-News,
May 31, 2020

4B-501. Notice to creditors by publication and notice to creditors by written notice (mailing or other delivery).
[For use with Rules 1B-304, 1B-306, and 1B-401 NMRA]

STATE OF NEW MEXICO
IN THE PROBATE COURT
DONA ANA COUNTY

No. 20-0074

IN THE MATTER OF THE ESTATE OF Juliet S Williams, DECEASED

NOTICE TO CREDITORS

NOTICE IS HEREBY GIVEN that the undersigned has been appointed personal representative of the estate of the decedent. All persons having claims against the estate of the decedent are required to present their claims within four (4) months after the date of the first publication of any published notice to creditors or sixty (60) days after the date of mailing or other delivery of this notice, whichever is later, or the claims will be forever barred. Claims must be presented either to the undersigned personal representative at the address below, or filed with the Probate Court of Dona Ana, 845 N. Motel Blvd. 1-201, Las Cruces, NM 88007.

Dated May, 2020
/s/ Edwin James Williams Jr
signature of representative

Edwin James Williams Jr
Printed Name

17093 White Pine Rd
Street address

Beaver dam, VA 23015
City, state, and ZIP code

#4213196, Sun-News, May 31 and Jun. 7, 14, 2020

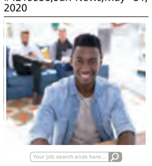
AGENDA ITEM for the DOÑA ANA COUNTY PLANNING AND ZONING COMMISSION

The Doña Ana County Planning and Zoning Commission will consider the following Agenda Item at its regular meeting on **Thursday, June 25, 2020 at 9:00 a.m.**, in the County Commission Chambers of the Doña Ana County Government Center, 845 N. Motel Blvd, Las Cruces, NM.

NEW BUSINESS DISCUSSION AND ACTION ITEMS

CASE # SU20-006: Submitted by Fred G. Mobley, on behalf of Family and Youth Inc., a request to expand the existing Raices del Saber Xinachtli Community School. The P&Z approved the charter school under Case # SU19-007. The expansion will include four (4) new portable buildings and total occupancy of 220 persons (205 Elementary Students and 15 staff members). The property address is 2215 N. Valley Drive and is located within Township 23 South, Range 1 East Section 11. It is described as being within USRS TRACTS 728-D & 9B-23 Re-plat No 1, Book 24, pages 11-12 as recorded in the Office of the Doña Ana County Clerk on August 2, 1996 under Instrument # 9617625. The subject parcel can be further identified by Parcel ID # R0330056.

#4215538,Sun-News,May 31, 2020



LRGPWWA Informal Request for Proposals #FY2020-03

The Lower Rio Grande Public Water Works Authority (LRGPWWA) is seeking Letters of Interest from qualified professional engineering, environmental and surveying firms for professional services for small water and/or wastewater projects less than $60,000 during FY2021through FY2024 (7/1/2020 to 6/30/24) on as "as needed" basis. Services may include and are not limited to engineering design, development or update of environmental or planning documents, construction administration and/or observation, surveying, mapping, permit acquisition, CAD drawings, GIS work, etc. Firms interested in provided these services shall provide a Letter of Interest, as specified below, no later than 3:00 p.m. on June 29, 2020 to:

Lower Rio Grande PWWA
Attention: Karen Nichols, Projects Manager
PO Box 2646, Anthony NM 88021
karen.nichols@LRGauthority.org (submission by email or file-share link is strongly preferred)

Letters of Interest shall contain a brief statement of qualification regarding specialized design and technical competence; capacity and capability of performing work as required; past performance with the LRGPWWA, its founding entities or other small water & wastewater systems; proximity to and familiarity with the LRGPWWA Service Area and utility systems; any special characteristic or capabilities which might enhance the firm's qualifications or suitability; and schedule of fees for various basic engineering, planning, surveying or other services. IMPORTANT: Letters of interest which do not include a schedule of fees will be deemed non-responsive. This requirement is intended to document the staff and services offered by the firm, and does not constitute a binding price commitment. Letters of Interest shall not be bound and shall be limited to five pages not including schedule of fees. Brochures or informational literature about the firm may be enclosed if desired.

The LRGPWWA anticipates that multiple firms will be selected for small project "as needed" during FY2021 through FY2024 and reserves the right to reject any and all proposals and to waive all formalities.

Martin G. Lopez,
General Manager
Kathi Jackson,
Chief Procurement Officer

#4211939, Sun-News,
May 31, 2020

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION
RULE 17.7.3 NMAC FILING
EL PASO ELECTRIC COMPANY
NOTICE OF 2021 INTEGRATED RESOURCE PLAN
2020-2021 PUBLIC ADVISORY PROCESS MEETINGS

Notice is hereby given that:

El Paso Electric Company ("EPE") invites members of the public to participate in the Integrated Resource Plan ("IRP") public advisory process through a series of public meetings. With public participation, EPE will develop its IRP pursuant to the New Mexico Efficient Use of Energy Act and the New Mexico Public Regulation Commission's ("Commission") IRP Rule, 17.7.3 NMAC. EPE's IRP is developed to identify cost--effective demand-side and supply-side electricity resources to serve EPE's customers over the next 20-year planning period.

The IRP will be submitted to the Commission no later than July 2021. Public participation is an important component of the development and implementation of EPE's integrated resource planning in New Mexico. EPE encourages interested members of the public to attend these public meetings to provide public input and commentary, whether as a residential or business customer, or as a representative of a trade, non-profit, neighborhood, shareholder, civic or other group.

Given the currently effective limitations on public gatherings in New Mexico and Texas, the first scheduled meeting will be held electronically and by phone conference on July 10, 2020, at 2:00 p.m. MDT. The IRP process will be explained, and additional meeting dates and locations will be set at that time. Prior to each meeting, the presentation for that meeting will be posted on EPE's website, www.epeletric.com. If you are interested in attending the meeting or otherwise participating in the process, please contact EPE by emailing NMIRP@epelectric.com or calling at (915) 543-4354.

#4190968, Sun-News, May 31, 2020

CES

LEGAL ADVERTISEMENT REQUEST FOR PROPOSAL

Cooperative Educational Services (CES) is accepting proposals in CES' online eProcurement system (https://eprocurement.ces.org) until Friday, June 26, 2020, 4:00 PM local time, for:

RFP# 2021-03 - Educational Facility Evaluation, Capital Outlay Long-Range Planning & Project Management

Release date: Monday, June 1, 2020, non-Mandatory Pre--Proposal eMeeting (Electronic Meeting): Thursday, June 4, 2020 @ 10:00 AM local time. To participate in the Pre-Proposal meeting by "Go To Meeting" or on the phone and for questions regarding this RFP, please contact the CES Procurement Department at 505-344-5470, M-F, except holidays, 8:30 a.m. - 4:30 p.m. or by email at bids@ces.org

Offeror's proposals, including Financial Statements shall be submitted electronically only, through the CES online eProcurement System (https://eprocurement.ces.org).

Hard copy proposals will NOT be accepted. To register your business and submit a proposal, you must have internet access and an email account.

Cooperative Educational Services reserves the expressed right to accept or reject any or all proposals.

/s/ David Chavez,
Executive Director
#4211560, Sun-News, May 31, 2020

NOTICE OF INTENT TO ADOPT

The City Council of The City of Las Cruces, New Mexico, Hereby Gives Notice of Its Intent to Adopt the Following Ordinance(s) at a Regular City Council Meeting to be Held on **June 15, 2020:**

(1) Council Bill No. 20-038; Ordinance No. 2930: An Ordinance Repealing and Replacing Sections 27-12-7-9, 27-12-7-9.2 and Adding a New Section 27-12-7-9.11 of Chapter 27, Traffic of the Las Cruces Municipal Code, 1997, as Amended (LCMC) Related to Utility Terrain Vehicles (UTVs) and Their Registration.

(2) Council Bill No. 20-039; Ordinance No. 2931: An Ordinance Approving a Zone Change from R-4 (Multi-Dwelling High Density – Limited Retail and Office to C-3 (Commercial High Intensity) for a Property Encompassing 5.22 + Acres Located at 2755 Idaho Avenue. Submitted by Kary Bulsterbaum, Representative. (20ZO0500043).

(3) Council Bill No. 20-040; Ordinance No. 2932: An Ordinance Approving a Zone Change from A-2 (Rural Agricultural District) and C-2 (Commercial Medium Intensity) to C-3 (Commercial High Intensity) for a Property Encompassing 7.93 + Acres Located at 3551 Bataan Memorial West. Submitted by City of Las Cruces, Property Owner. (20ZO0500045).

(4) Council Bill No. 20-041; Ordinance No. 2933: An Ordinance Approving a Zone Change from O-1 (Office, Neighborhood – Limited Retail Service) to R-4 (Multi-dwelling High Density – Limited Retail and Office) for Three Properties Located at 1512, 1518, and 1524 S Espina Street. Submitted by Jaime Gardea, Property Owner. (20ZO0500012).

Copies Are Available for Inspection During Working Hours at the Office of the City Clerk. **Witness My Hand and Seal** of the City of Las Cruces on this **the 27th day of May 2020.**

Christine Rivera, CMC

#4215213, Sun-News,
May 31, 2020

Attachment E-1: Proof of Notice

From:	Griego, Patricia
To:	Burns, Nancy; Griego, Patricia; Jeffrey Wechsler; Diana Luna; Kari Olson; Lorraine Talley; John F. McIntyre; Schichtl, James; Hutcheson, Marvin C; Novela, Mariah M; Parsons, Judith M; Pleasant, Linda G; Perea, Araceli G; "astevens.law@gmail.com"; "jvega-brown@las-cruces.org"; "joprovencio@las-cruces.org"; "llarocque@las-cruces.org"; "marcyd@las-cruces.org"; davila@las-cruces.org; "JAG@las-cruces.org"; "hconnelly@las-cruces.org"; "ddollahon@las-cruces.org"; "tomf@donaanacounty.org"; rockybacchus@gmail.com; ecomaxac@lifeisgood2.com; "lellis@nmsu.edu"; "ghaubold@ad.nmsu.edu"; "jdrake@modrall.com"; "nwinter@stelznerlaw.com"; kherrmann@stelznerlaw.com; rgallegos@stelznerlaw.com; "Noble.ccae@gmail.com"; stephanie@dzur-Law.com; Lundin, Robert; gelliot@nmag.gov; Cholla Khoury; "lawoffice@jasonmarks.com"; "Jsmith.watsonlawlc@gmail.com"; mayortrujillo@cityofanthonynm.org; "mlsoules@hotmail.com"; "bthroneatty@newmexico.com"; Goodin, Nelson; fredk@donaanacounty.org; "Rick@votesolar.org"; tasolomon6@gmail.com; "Dahlharris@hotmail.com"; "Jdittmer@utilitech.net"; "Jaherz@sawvel.com"; akharriger@sawvel.com; Borman, Bradford, PRC; Reynolds, John, PRC; Chavez, Milo, PRC; Sidler, Jack, PRC; john.bogatko@state.nm.us; marc.tupler@state.nm.us; gilbertt.fuentes@state.nm.us; Sisneros, Anthony R., PRC; Leyba-Tercero, Elisha, PRC; Fisk, Russell, PRC; Amer, Judith, PRC; Smith, Michael C, PRC; Martinez-Rael, Peggy, PRC; elizabeth.ramirez@state.nm.us; carolyn.glick@state.nm.us; Hurst, Elizabeth, PRC; christopher.ryan@state.nm.us; philipbsimpson@comcast.net; "Kyle.j.smith124.civ@mail.mil"; robert.a.ganton.civ@mail.mil; hgeller@swenergy.org; jbrant@swenergy.org; "ctcolumbia@aol.com"; l.tougas@cleanenergyregresearch.com; dgegax@nmsu.edu; "Ramona.blaber@sierraclub.org"; "sricdon@earthlink.net"; "smichel@westernresources.org"; Beadles, Cydney, PRC; pat.oconnell@westernresources.org; april.elliott@westernresources.org; "dneid@cox.net"; schaefno@gmail.com; david@vw77.com; bslocum@dwmrlaw.com; jmcnally@dwmrlaw.com; mbarker@dwmrlaw.com; mzidovsky@montand.com
Cc:	EPE_Reg_Mgmt
Subject:	Rule 17.7.3 NMAC Filing EPE"s Notice of 2020-2021 Public Advisory Process Meetings for 2021 IRP & COS
Date:	Thursday, June 4, 2020 10:50:41 AM
Attachments:	2021 IRP Notice.pdf COS Notice of IRP Process.pdf

Good morning. Attached is El Paso Electric Company's Notice of its 2020-2021 Public Advisory Process Meetings for the 2021 Integrated Resource Plan and Certificate of Service, that was filed by email with NMPRC Records today.

Patricia "Trish" Griego| **El Paso Electric Company**
Legal Assistant
300 Galisteo St. Suite 206
Santa Fe, New Mexico 87501
T: (505) 982-4713 | C: (505) 470-4048
Patricia.griego@epelectric.com

Attachment E-1: Proof of Notice

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

CERTIFICATE OF SERVICE

RULE 17.7.3 NMAC: NOTICE OF IRP PROCESS

I HEREBY CERTIFY that the foregoing copy of **El Paso Electric Company's ("EPE") Proof of Publication and Declaration of Curtis Hutcheson of Notice to Customers,** was served on the New Mexico Public Regulation Commission, Intervenors in EPE's most recent rate case (NMPRC Case No.20-00104-UT), renewable energy procurement plan case (NMPRC Case No.19-00099-UT), energy efficiency case (NMPRC Case No.18-00116-UT) and IRP Proceedings (Case No. 18-00293-UT) on May 13, 2021 as indicated below to each of the following:

Via Email to:

Nancy B. Burns	nancy.burns@epelectric.com;
Patricia Griego	patricia.griego@epelectric.com;
Jeffrey Wechsler	jwechsler@montand.com;
Diana Luna	dluna@montand.com;
Kari Olson	kolson@montand.com;
Teresa Pacheco	tpacheco@montand.com;
James Schichtl	james.schichtl@epelectric.com;
Curtis Hutcheson	curtis.hutcheson@epelectric.com;
Judith Parsons	judith.parsons@epelectric.com;
Linda Pleasant	linda.pleasant@epelectric.com;
Araceli Perea	Araceli.pera@epelectric.com;
Anastasia Stevens	astevens.law@gmail.com;
Jennifer Vega-Brown	jvega-brown@las-cruces.org;
Tom Figart	tomf@donaanacounty.org;
Rocky Bacchus	rockybacchus@gmail.com;
Allen Downs	ecomaxac@lifeisgood2.com;
Joan Drake	jdrake@modrall.com;
Nann Winter	nwinter@stelznerlaw.com;
Keith Herrmann	kherrmann@stelznerlaw.com;
Stephanie Dzur	stephanie@dzur-law.com;
Gideon Elliott	gelliot@nmag.gov;
Cholla Khoury	ckhoury@nmag.gov;

Attachment E-1: Proof of Notice

Jason Marks	lawoffice@jasonmarks.com;
Mayor Trujillo	mayortrujillo@cityofanthonynm.org;
Merrie Lee Soules	mlsoules@hotmail.com;
Bradford Borman	bradford.borman@state.nm.us;
John Reynolds	john.reynolds@state.nm.us;
Philip B. Simpson	philipbsimpson@comcast.net;
Kyle Smith	kyle.j.smith124.civ@mail.mil;
Steve Michel	smichel@westernresources.org;
Cydney Beadles	cydney.beadles@westernresources.org;
April Elliott	april.elliott@westernresources.org;

DATED this 13th day of May 2021.

/s/ Trish Griego
Trish Griego
Legal Assistant

Attachment E-2: Orignal and Final Meeting Schedule

2020-21 Original Schedule

Meeting	*Date*	*Day*
First Meeting - Present current IRP, forecast, L&R	**7/10/2020**	**Fri**
Second Meeting - Request resources	**8/14/2020**	**Fri**
Third Meeting - Present Expansion Modeling (EIM, SPP, etc.)	**10/7/2020**	**Wed**
Fourth Meeting - Present preliminary final resource protfolio (draft IRP)	**5/14/2021**	**Fri**
Fifth Meeting - Present final resource portfolio (final IRP)	**6/15/2021**	**Tue**
Sixth Meeting - Receive feedback on final IRP	**7/1/2021**	**Thu**
File at NMPRC	**7/15/2021**	**Thu**

2020-21 Final Schedule

Meeting	*Date*	*Day*
First Meeting - Present current IRP, forecast, L&R	**7/10/2020**	**Fri**
Second Meeting - Request resources	**8/14/2020**	**Fri**
Third Meeting - Present Expansion Modeling (EIM, SPP, etc.)	**10/7/2020**	**Wed**
Fourth Meeting - Public Participants Presentation	**11/9/2020**	**Mon**
Fifth Meeting - Present Modeling Update	**2/5/2021**	**Fri**
Sixth Meeting - Present Modeling Status,	**3/19/2021**	**Fri**
Seventh Meeting - Present Load Forecast and Peliminary Modeling Results	**6/1/2021**	**Tue**
Eighth Meeting - Presented Jurisdictional Analysis and Comments Draft IRP	**7/1/2021**	**Thu**
Ninth Meeting - Receive Feedback on Final IRP	**9/2/2021**	**Thu**
File at NMPRC	**9/16/2021**	**Mon**

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

CERTIFICATE OF SERVICE

RULE 17.7.3 NMAC

I HEREBY CERTIFY that **El Paso Electric Company's Integrated Resource Plan for the Period 2021-2040**, was emailed on September 16, 2021 to each of the following:

Nancy Burns	nancy.burns@epelectric.com;
Jordan Kessler	jordan.kessler@epelectric.com;
Patricia Griego	patricia.griego@epelectric.com;
Jeffrey Wechsler	jwechsler@montand.com;
Kari Olson	kolson@montand.com;
Teresa Pacheco	tpacheco@montand.com;
Diana Luna	dluna@montand.com;
Yolanda Sandoval	ysandoval@montand.com;
James Schichtl	james.schichtl@epelectric.com;
Curtis Hutcheson	curtis.hutcheson@epelectric.com;
Omar Gallegos	omar.gallegos@epelectric.com;
Manuel Gomez	manuel.gomez@epelectric.com;
Victor Martinez	victor.martinez@epelectric.com;
Rico Gonzales	rico.gonzales@epelectric.com;
Anastasia Stevens	astevens.law@gmail.com; jvega-
Jennifer Vega-Brown	brown@las-cruces.org;
Tom Figart	tomf@donaanacounty.org;
Fred Kennon	fredk@donaanacounty.org;
Rocky Bacchus	rockybacchus@gmail.com;
Allen Downs	biz@lifeisgood2.com;
Joan Drake	jdrake@modrall.com;
Nann Winter	nwinter@stelznerlaw.com
Keith Herrmann	kherrmann@stelznerlaw.com;
Stephanie Dzur	stephanie@dzur-law.com;
Gideon Elliot	gelliot@nmag.gov;
Cholla Khoury	ckhoury@nmag.gov;
Jennifer Van Wiel	jvanwiel@nmag.gov;
Jason Marks	lawoffice@jasonmarks.com;
Mayor Trujillo	mayortrujillo@cityofanthonynm.org;
Merrie Lee Soules	mlsoules@hotmail.com;
Stephen Fischmann	stephen.fischmann@state.nm.us;
Joseph Maestas	joseph.maestas@state.nm.us;
Theresa Becenti-Aguilar	t.becenti@state.nm.us;
Jefferson Byrd	jeff.byrd@state.nm.us;
Cynthia Hall	cynthia.hall@state.nm.us;
Bradford Borman	bradford.borman@state.nm.us;
John Reynolds	john.reynolds@state.nm.us;
Jack Sidler	jack.sidler@state.nm.us;
Georgette Ramie	georgette.ramie@state.nm.us;
Elisha Leyba-Tercero	elisha.leyba-tercero@state.nm.us;
Milo Chavez	milo.chavez@state.nm.us;
John Bogatko	john.bogatko@state.nm.us;

Marc Tupler	marc.tupler@state.nm.us;
Gabriella Dasheno	gabriella.dasheno@state.nm.us;
David Black	david.black@state.nm.us;
Michael Smith	michaelc.smith@state.nm.us;
Russell Fisk	russell.fisk@state.nm.us;
Elizabeth Ramirez	elizabeth.ramirez@state.nm.us;
Peggy Martinez-Rael	peggy.martinez-rael@state.nm.us;
Philip B. Simpson	philipbsimpson@comcast.net;
Kyle Smith	kyle.j.smith124.civ@mail.mil;
Andrea Crane	ctcolumbia@aol.com;
Steve Michel	smichel@westernresources.org;
Cydney Beadles	cydney.beadles@westernresources.org;
April Elliott	april.elliott@westernresources.org;
Lisa Hickey	lisahickey@newlawgroup.com;
Don Kurtz	donkurtz7@gmail.com;
Anna Perkins	anna.perkins@ccrenew.com;
Nicko Keene	keene@ccrenew.com;
Pat O'Connell	pat.oconnell@westernresources.org;
Robert Byland	turso3@me.com;
Charles Turner	cturner11060@gmail.com;
Carol Winkler	cwinkler8@gmail.com;
Walton Low	waltonlow@gmail.com;
Cassie McClure	cassiemcclure@gmail.com;
Lorenzo Perea	lperea@solarsmartliving.com;
Oswaldo De Santiago	oswaldo.desantiago@gmail.com;
Alton Luper	aluper@zianet.com;
Carrie Bellamy	cbellamy@nationalgridrenewables.com;
Brian Johnson	brian@nmreta.net;
Paul Robson	paul.robson@highviewpower.com;
Doug Patterson	doug@blackforestpartners.com;
Beth Bardwell	betbardwell@gmail.com;
Ryan Brown	ryanbrownsf@gmail.com;
Joshua Simmons	j.blaine.s.ee@gmail.com;
James Kruszynski	james.p.kruszynski.ctr@mail.mil;
Melissa DeValles	melissa.devalles@maltainc.com;
Eli LaSalle	eli.lasalle@state.nm.us;
Emily McCrorie	emily.mccrorie@ccrenew.com;

DATED this 16th day of September 2021.

*/s/Trish Griego*______
Trish Griego
Legal Assistant