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July 16, 2015

VIA HAND DELIVERY

Ms. Melanie Sandoval
Records Bureau
New Mexico Public Regulation Commission
1120 Paseo de Peralta
Santa Fe, NM 87501

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

Enclosed for filing please find the original of El Paso Electric Company's ("EPE") Integrated Resource Plan ("IRP") for the period 2015-2034, and includes EPE's four year Action Plan. 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 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 web site at www.epelectric.com.
- Copies are being delivered to the Chairwoman and Commissioners, General Counsel of the NMPRC and NMPRC Staff members who participated in the IRP Public Advisory Group.
- Copies are being served electronically to the persons listed on EPE's pending Rate Case No. 15-00127-UT.
- Additionally, EPE has notified all active participants in EPE's Public Advisory Group that the IRP is available on the website.

Attached to this letter are an original and copy of the IRP. Please conform and return the one extra copy to our messenger. If you have any questions, please contact me Randy Childress at (505) 982-4147. Thank you.

Very truly yours,

Randall Childress

Enclosures

cc:

Chairwoman Karen Montoya
Commissioner Sandy Jones
Commissioner Valerie Espinoza
Commissioner Patrick Lyons
Commissioner Lynda Lovejoy
Michael Smith, NMPRC General Counsel
Elisha Leyba-Tercero, NMPRC Staff
Dwight Lamberson, NMPRC Staff
Bruno Carrrara, NMPRC Staff
Jack Sidler, NMPRC Staff
John Reynolds, NMPRC Staff
Sandra Skogen, NMPRC Staff
Cydney Beadles, NMPRC Staff

INTEGRATED RESOURCE PLAN

OF

EL PASO ELECTRIC COMPANY

FOR THE PERIOD 2015-2034

July 16, 2015

SAFE HARBOR STATEMENT

Certain matters discussed in this Integrated Resource Plan ("IRP") other than statements of historical information are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond El Paso Electric Company's ("EPE" or the "Company") control, and many of which could have a significant impact on the Company's operations, results of operations, and financial condition, and could cause actual results to differ materially from those anticipated. For further discussion of these and other important factors, please refer to the Company's Annual Report on Form 10-K and Quarterly Reports on Form 10-Q filed with the Securities and Exchange Commission. These reports are available online at www.epelectric.com or www.sec.gov.

The information in this IRP is based on the most up-to-date information reasonably available to EPE at the time of preparation. The Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events, except to the extent the events or circumstances constitute material changes in this IRP that are required to be reported to the New Mexico Public Regulation Commission ("NMPRC" or "Commission") pursuant to its IRP Rule, 17.7.3 New Mexico Administrative Code.

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ATTACHMENTS

I. EXECUTIVE SUMMARY

EPE presents its 2015 Integrated Resource Plan ("IRP") pursuant to the requirements of the Commission's IRP Rule, 17.7.3 NMAC. This document discusses EPE's integrated resource planning process and develops an integrated resource portfolio to safely, reliably and cost-effectively meet the energy needs of EPE's customers for the next twenty years. EPE's 2015 IRP builds upon EPE's 2009 and 2012 IRPs previously approved by the Commission.

On April 20, 2015 EPE filed a Notice of Material Change to its 2012 IRP that provided notice of EPE's opportunity to construct, own and operate several small solar facilities on land provided by the military. EPE has filed for certificate of convenience and necessity ("CCN") approval of a 20 MW Ft. Bliss solar facility and a 5 MW Holloman Air Base solar facility. Because EPE's 2015 Load and Resource Document does not show a new capacity need until 2022, the proposed solar facilities are not included in EPE's 2015 base case, which represents EPE's most cost effective resource portfolio.

EPE plans its system needs as a whole and incorporates into its planning process the requirements of New Mexico's Renewable Energy Act ("REA"), NMSA 1978 § 62-1-16 et seq. and Efficient Use of Energy Act ("EUEA") NMSA 1978 § 62-1-17 et seq. EPE's 20-year resource portfolio is environmentally responsible and includes a mix of energy efficiency and demand-side management resources and renewable energy and traditional supply-side generating resources.

In preparing its IRP, EPE conducted a 14-month public participation process with an active and involved New Mexico working group. These meetings were open to the public and attended by a variety of groups and interested EPE customers. The goal of the public advisory process has been to develop, in cooperation with the public working group and other interested parties, a safe, reliable and cost effective resource portfolio that minimizes environmental impacts.

Based on input received during the public advisory process, EPE modeled and analyzed seven scenarios, incorporating numerous qualitative factors, and performed various risk analyses to develop its 20-year resource portfolio. The scenarios incorporated differing assumptions for system load growth, natural gas price and carbon tax. EPE's least-cost resource additions over the next ten years that result from its IRP Study Process are summarized in the TABLE 1 below. With the exception of the previously approved Montana Power Station ("Montana") Units 3 and 4, the identified resource additions are dependent ongoing analyses through EPE's planning processes, including future IRP processes, and will be subject to regulatory approval. Accordingly, the identified resource additions may differ based on future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards.

TABLE 1. 10-Year EPE Least-Cost Resource Additions

YEAR	RESOURCE	SIZE (MW)	JURISDICTION
2016	Montana Unit 3 Montana Unit 4	88 88	NM, TX NM, TX
2022	Gas-Fired Combined Cycle Unit	281	NM, TX
2024	Gas Fired Combined Cycle Unit Solar PV	281 10	NM, TX NM, TX
2025	Gas-Fired Combustion Turbine Solar PV	88 20	NM, TX NM, TX

EPE's 2015 IRP provides a mix of peak, intermediate and base load generation, and includes a mix of fossil fuel and renewable energy. While the timing of resource additions differs based on operational sensitivities, similar resources are added under a range of scenarios demonstrating that EPE's resource portfolio is robust. EPE's IRP, together with the related Four-Year Action Plan, is intended to be periodically reviewed and updated in response to changes in load, impact of energy efficiency measures, fuel cost projections, and implementation of carbon tax levels or other environmental considerations.

EPE's Action Plan for 2016 through 2019 is as follows:

1. EPE will complete the regulatory process to terminate its participation and sell its ownership interest in the Four Corners Power Plant in July 2016.
2. EPE will complete the regulatory process for approval of its 2015 Annual Renewable Energy Plan Application filed with the Commission (15-00117-UT); and will file annual renewable energy plan application on May 1 in 2016, 2017, 2018 and 2019 pursuant to Rule 17.9.572 NMAC and the REA.
3. EPE will file annual applications for Commission approval of proposed energy efficiency measures or programs and load management measures or programs on July 1, beginning 2016 pursuant to Rule 17.7.2 NMAC and the EUEA.
4. EPE will issue a request for proposal ("RFP") process for a pilot demand response program to evaluate a demand-side management program.
5. EPE will issue an All-Source RFPs in 2016 or 2017 to address the resource need identified in 2022. The exact date for the RFP will be determined based on a continued evaluation of future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards as mentioned before.

II. SUMMARY OF EPE'S 2012 IRP ACTION PLAN

EPE’s 2012 IRP Action Plan included the addition of 4 LMS100 generating units by 2017; completion of a negotiation and regulatory process to purchase power from a 50MW solar project; completion of a regulatory process to procure biomass renewable resources to meet the New Mexico Renewable Portfolio Standard (“RPS”) and Rule 17.9.572 NMAC requirements; and the completion of a regulatory process in the Texas jurisdiction to add 2.6MW of solar facilities. EPE's 2012 Action Plan was accepted and was implemented with some modifications to the resources and timing of the proposed resource additions.

EPE sought and obtained regulatory approvals to own, construct and operate Montana Units 1 through 4. Montana Units 1 and 2 have been built and are operating. Montana Units 3 and 4 are under construction and are scheduled to be operational by summer 2016 and 2017, respectively. EPE did enter a contract and obtained regulatory approval to purchase solar energy from the 50 MW Macho Springs solar facility. EPE has been purchasing energy from this facility since 2013. EPE did not obtain regulatory approval to procure biomass renewable resources because of the cost and did not receive regulatory approval in Texas for the addition of several solar projects.

III. INTEGRATED RESOURCE PLANNING OVERVIEW

EPE's 2015 IRP responds to the requirements of the EUEA and the Commission's IRP Rule, 17.7.3 NMAC. The objective of the IRP process is to identify the most cost effective portfolio of resources to supply the energy needs of EPE's customers. In developing a cost effective resource portfolio, the IRP must "evaluate renewable energy, energy efficiency, load management, distributed generation and conventional supply-side resources on a consistent and comparable basis and take into consideration risk and uncertainty of fuel supply, price volatility and costs of anticipated environmental regulations." NMSA 1978, § 62-17-10. EPE prefers resources that minimize environmental impacts, where the costs and service quality for alternative resources are equivalent. Also, to the extent EPE must meet statutory obligations regarding energy efficiency and renewable energy mandates, these goals and requirements are incorporated in EPE's planning process. For example, the EUEA establishes energy efficiency targets and energy efficiency programs are approved by the Commission. In addition, the REA establishes a RPS for EPE's New Mexico jurisdiction, based on a percentage of EPE's annual New Mexico retail energy sales, and the NMPRC has additional diversity requirements. Utilities are not required to add additional REA resources when costs exceed a reasonable cost threshold (“RCT”). EPE’s RPS portfolio is currently above the RCT, has and EPE has approved variances and waivers from further REA procurements through 2016. EPE is in compliance with the REA.

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

1) Description of existing electric supply-side and demand-side resources;
2) Current load forecast as described in this rule;
3) Load and resources table;
4) Identification of resource options;
5) Description of the resource and fuel diversity;
6) Identification of critical facilities susceptible to supply-source or other failures;
7) Determination of the most cost effective resource portfolio and alternative portfolios;

8) Description of public advisory process;

9) Action plan; and

10) Other information that the utility finds may aid the commission in reviewing the utility's planning processes.

17.7.3.9.B NMAC. Because public input is critical to the development and implementation of integrated resource planning in New Mexico, development of the IRP also incorporates a public advisory process. NMSA 1978, § 62-17-10; 17.7.3.9.H NMAC.

Once completed and accepted by the Commission, the IRP is both a planning tool and an action tool. The IRP develops a 20-year resource portfolio which is updated every three years.

The IRP also identifies an Action Plan that details the specific actions EPE will take to implement the IRP during the next four-year period. The Action Plan is updated in the event there are any material events or changes that would impact the anticipated resource acquisitions.

IV. EPE'S PUBLIC ADVISORY PROCESS

EPE recognizes the importance of public involvement and input in the effective planning on a long-term basis for the resource needs of all of its customers, and employed a public advisory process throughout the course of its IRP development. EPE began its public advisory meetings in May 2014, approximately 14 months prior to the filing date of this IRP. The purpose of EPE's public advisory process has been to receive public input, and to solicit public comment concerning EPE's resource planning and related resource acquisition issues.

Resource planning and coordination of public involvement and input is critical for a multi-jurisdictional utility such as EPE, which has regulatory obligations that differ by jurisdictional authority and customer preferences that may also differ by jurisdictional service areas. EPE has retail operations in Texas and New Mexico, and its electric system includes generating stations and transmission facilities located in Texas, New Mexico and Arizona. As described below, EPE's New Mexico jurisdictional retail operations represent approximately 24 percent of its total retail customers. Although EPE has no IRP requirements in its Texas jurisdiction, because the electric system is planned for as a whole, EPE evaluates the needs of all operating segments and retail customers in the planning process.

A. EPE'S PUBLIC OUTREACH AND MEETINGS

EPE’s public advisory included a series of public meetings and other customer outreach activities. EPE initiated the public advisory process by providing notice 30 days prior to the first scheduled meeting to: the Commission, interveners in its most recent general rate case (NMPRC Case No. 09-00171-UT), participants in its most recent renewable energy procurement case at the time (NMPRC Case No. 13-00223-UT), and participants in its most recent energy efficiency case (NMPRC Case No. 13-00176-UT). The notice and certificates of service were filed with the Commission's Records Bureau. EPE published notice in the Las Cruces Sun-News, a newspaper of general circulation in every New Mexico County in which EPE serves. EPE also included notice of the public advisory group meetings in EPE’s Connections newsletter, included in all New Mexico customers’ bills.

Throughout the 14-month period for public input, EPE solicited participation and input from customers and other interested parties. EPE posted notices of each upcoming meeting on its website, along with related materials, and also maintained an electronic mailing list of meeting participants and other interested parties.

EPE's initial meeting, "Kick-off Meeting," was in Las Cruces on May 22, 2014. During the initial introductory meeting with the public advisory group, EPE outlined proposed procedures and topics and provided an overview of EPE's system and resources needs. Thereafter, EPE scheduled meetings in Las Cruces on a monthly basis. At each meeting EPE chaired the meeting and provided participants the opportunity to ask questions about previous meeting topics and discussions; developed and circulated presentations; accommodated presentations by public participants; provided a new topic for discussion; and EPE provided an additional question and answer period. EPE also allowed participants to present material and topics they found were relevant to the IRP. EPE provided telephonic and webinar access for each meeting.

EPE's public advisory group outreach resulted in a diverse group of stakeholder participants. TABLE 2 presents the New Mexico stakeholder representation in EPE's IRP process.

TABLE 2. New Mexico Stakeholder Representation

Stakeholder Area	Participants & Invitees
Regulatory	NMPRC Utility Division Staff
Government	City of Las Cruces (“CLC”), Dona Ana County (“DAC”), New Mexico Attorney General, State Representatives and Senators, New Mexico Energy, Minerals, and Natural Resources Department
Business and Industry	New Mexico State University ("NMSU"), U.S. Army, Balanced Power Engineering Inc. ("BPEI"), Verde Realty, White Sands Missile Range ("WSMR"), Positive Energy, Sunspot Solar Energy, Energy Strategies
Non-profit Advocacy Organizations	Coalition for Clean Affordable Energy (“CCAE”), Western Resource Advocates ("WRA"), Sierra Club, Southwest Energy Alliance
Citizens/customers	Hui-Chu Su Johnson, David Johnson, Rocky Bacchus, Dan Townsend, David Hull, Merrie Lee Soules, Allen Downs
Peer Utilities	Public Service of New Mexico ("PNM"), New Mexico Gas Company

EPE had consistent participation from both a core group of customers and other interested parties. As shown on TABLE 2 above, stakeholders in EPE's advisory process who actively participated or were regularly invited to each meeting included City of Las Cruces, Dona Ana County, NMSU, Department of Defense and representatives of EPE's military customers, New Mexico Attorney General, State Representatives and Senators, Public Service Company of New Mexico, and the Commission's Utility Division Staff. Some of the individual customers who participated were also active participants in EPE's prior public process for its 2009 and 2012 IRPs. On average, EPE had 10 participants per meeting, either in person or through the webinar.

Through the public advisory process, EPE was able to provide information to, and receive and consider input from, the public regarding the development of its IRP. Topics discussed as part of the public participation process included, but were not limited to, EPE's load forecast; discussion of existing supply-side and demand-side resources; EPE's assessment of its need for additional resources; the identification of resource options; and modeling and risk assumptions and the cost and general attributes of potential additional resources; and EPE's initial assessment of the most cost-effective portfolio of resources for the IRP. In addition, EPE held an Open Public Participation meeting in which the participants were encouraged to make their own presentations to the group. TABLE 3 provides the New Mexico advisory group meetings by date and subject matter discussed.

TABLE 3. Advisory Group Meetings

Date	Subject Matter
5/22/2014	Kick-off and Introduction Explanation of IRP Process and Goals EPE System Overview
6/19/2014	Long-term Demand and Energy Forecasting Resource Planning Process and Overview
7/17/2014	Conventional Capacity and Generation Option Considerations
8/21/2014	Open Public Participation
9/18/2014	Renewable Energy Options Renewable & Conventional Power Plant Siting and Environmental Considerations
10/16/2014	Transmission & Distribution Systems Overview and Projects
11/13/2014	Energy Efficiency Programs and Options
12/11/2014	Rate Considerations and Potential Impacts on Resource Planning Decisions

2/5/2015	Resource Planning Base Case Assumptions Initial Cost Estimates for Resource Planning Options
4/9/2015	Presentation of New Load Forecast
5/7/2015	Presentation of Resulting 20-year Expansion Plan
6/8/2015	Presentation to NMPRC Staff

Although prepared materials were provided prior to and at each open public meeting, which formed the basis of the subject matter discussion, meetings were conducted in an informal manner, encouraging participation by the attendees EPE answered most questions at the meeting where asked; and otherwise, answers were provided at the beginning of the subsequent meeting. All meetings were conducted in the same fashion consisting of:

- welcome, reminder of the purpose of IRP, identification of the scheduled subject matter, and an appeal for feedback and input
- date of next meeting
- follow-up to unanswered questions and a general invitation for further discussion of the previous meeting(s)
- introduction of subject matter presenter
- presentation and discussion of presentation material and/or subject matter

In order to make the IRP process as accessible to the public as possible, notice of all public meetings, meeting presentations, and other relevant documents were posted on EPE's web site. In addition to the 11 public meetings held in Las Cruces, EPE held a meeting in Santa Fe with Commission Staff to present EPE's conclusions and recommendations and incorporate input.

B. PUBLIC ADVISORY GROUP INPUT AND RECOMMENDATIONS

The most active participation in the public advisory process came from a few very engaged EPE customers and representatives. Public participants were encouraged to engage in various discussion items related to each presentation, as well as discussion items completely unrelated to the presentation but related to resource options in the IRP process. Those customers who actively participated in the process vigorously discussed the topics that were presented at public meetings. Participants demonstrated a general knowledge of the electric system and, an appreciation to some degree of the complexity of resource planning. The participant's level of understanding facilitated detailed discussions of planning alternatives, such as distributed solar generation, demand side management programs, and rate options to encourage conservation and efficiency..

EPE received and considered all input and recommendations made during the public advisory process. Particular attention was paid to those proposals that were consistent with sound resource planning principles and accepted good engineering practices. For example, based on the input from one participant, EPE used the lower end of the pricing for wind and solar projects modeled by the Company as discussed later in this report. However, based on input from a NMPRC Staff member, EPE also ran a sensitivity analysis at the high end of pricing because he expressed concern that solar prices in the base case where too low.

One participant expressed interest in EPE implementing a pilot demand response program with his own company. While EPE did not pursue that specific proposal, EPE requested in its recently filed rate case, Case No. 15-00127-UT, approval to recover the cost of a RFP process to initiate a pilot Demand Response program. As addressed in more detail in this report and in the rate case, the proposed program would be open to residential and small commercial customers. EPE is proposing to issue an RFP to solicit proposals from vendors or contractors interested in participating in the program.

Another participant recommended that EPE delay retirement of Rio Grande Unit 6 ("Rio 6") in order to prevent base rate increases. However, EPE's 2012 IRP demonstrated that Unit 6 would be retired at the end of 2014, and that EPE would construct several small gas units as part of its, most cost-effective, base case scenario. Consistent with the 2012 IRP, EPE filed two CCN applications in New Mexico for Montana Units 1 and 2 and Montana Units 3 and 4, which also addressed that Rio 6 would be retired at the end of 2014.The CCNs were approved by the Commission. Based on those approvals, EPE moved forward with the construction of the Montana units and subsequently placed Rio 6 in inactive reserve status. Montana Units 1 and 2 came on-line March 19 and 20, 2015, respectively. Rio 6 last operated on March 24, 2015. In addition, EPE performed studies that demonstrated the additional capital costs required to continue to operate the unit were not favorable. The same participant also asked EPE to evaluate thorium-based nuclear reactors as a resource. EPE evaluated these resources and found they are considered experimental resources. Accordingly, EPE did not consider them as an alternative for this IRP.

At the request of certain public advisory participants, EPE agreed to provide all participants the opportunity to provide their own written comments on their input and recommendations during the IRP public advisory process. The written comments of those participants are attached to the IRP as Attachment F, and EPE does not endorse any of statements contained in those comments.

V. DESCRIPTION OF EPE'S SERVICE AREA

EPE's IRP process is responsive to the operating characteristics and challenges of its multi-state service area. EPE's service territory covers approximately 10,000 square miles extending from Hatch, New Mexico to Las Cruces to El Paso and then further east to Van Horn, Texas. EPE offers retail electric service in both Texas and New Mexico to approximately 400,000 customers, with approximately 24 percent of customers located in New Mexico.

EPE provides electricity to approximately 94,500 customers in New Mexico (88 percent are within the residential customer class). EPE's New Mexico service area encompasses Las Cruces, and nearby municipalities located in the counties of Dona Ana, Luna, Otero, and Sierra, New Mexico. EPE also serves institutional and public sector customers such as New Mexico State University, the Las Cruces Public School District, and city, county and other municipal entities. EPE also serves two major military installations in New Mexico, White Sands Missile Range and Holloman Air Force Base.

EPE's New Mexico residential customer class includes approximately 83,000 service meters as of December 2014. In 2014, EPE's New Mexico residential customer classes used approximately 643,000 megawatt-hours ("MWh") of energy; residential usage per customer in 2014 was approximately 650 kilowatt-hours ("kWh") per month. Primary energy use goes to lighting, cooling and heating. EPE's New Mexico commercial, industrial and public sector customer classes used approximately 998,000 MWh of energy during 2014.

EPE serves its customers with a variety of resources, including EPE-owned generating facilities that are located both in EPE's control area ("local") and outside EPE's control area ("remote"). FIGURE 1 is a map depicting the location of EPE's generating stations.

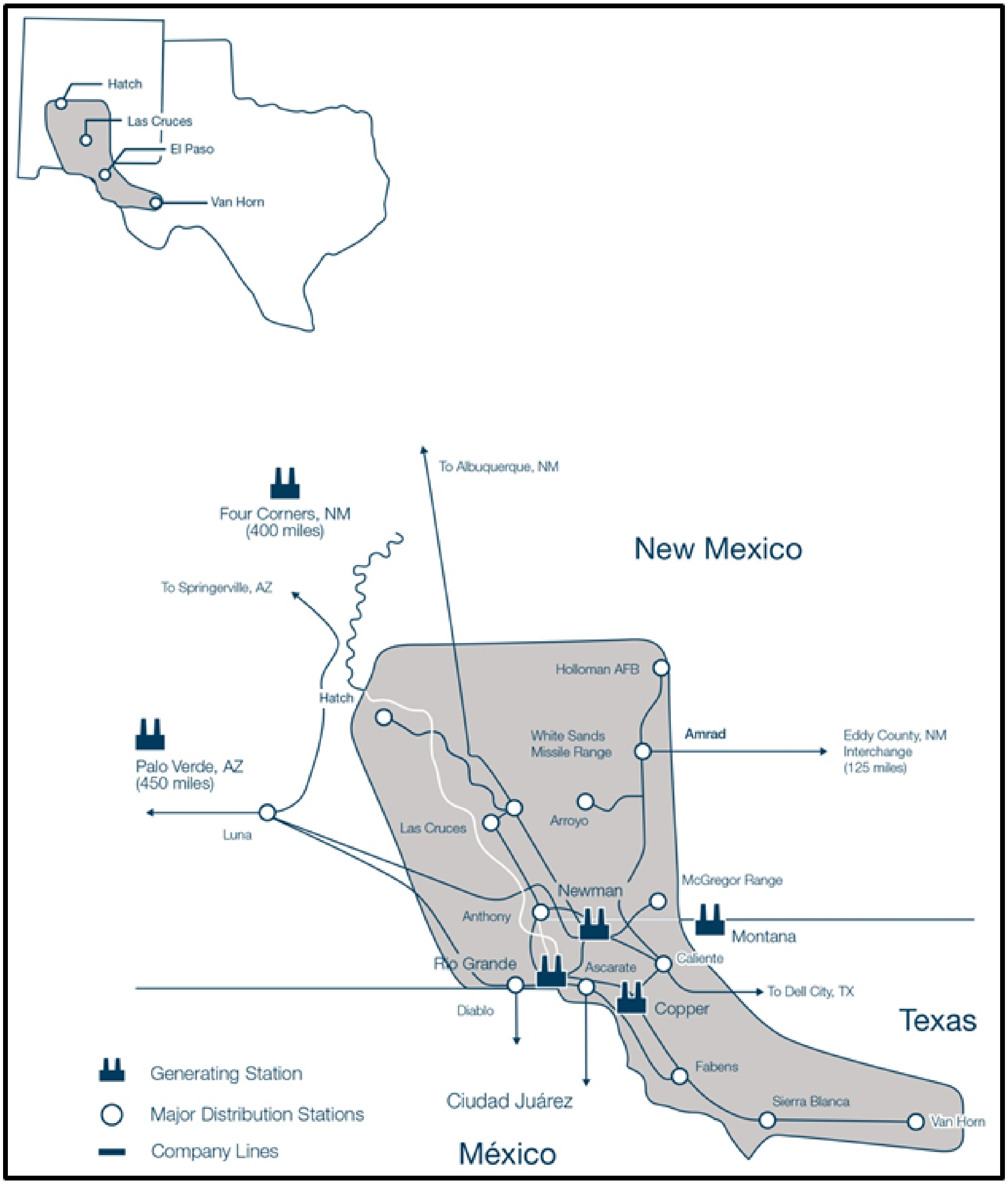


FIGURE 1. Map of EPE's Generating Station

EPE is an interconnected member of the Western Electricity Coordinating Council ("WECC") and is located in the far southeast corner of this organization. The WECC spans a geographic area that, starting with El Paso, reaches north to include two Canadian provinces and stretches west to include all or part of 14 western states as well as northern Baja California, Mexico. EPE is not interconnected to the Electric Reliability Council of Texas ("ERCOT"). EPE is connected to the Southwest Power Pool ("SPP") through an asynchronous High Voltage Direct Current ("HVDC") tie. In total, EPE owns, in whole or in part, approximately 950 miles of multiple 345 kV transmission lines, most of which are located within New Mexico. FIGURE 2 depicts EPE's major transmission facilities and interconnection points.

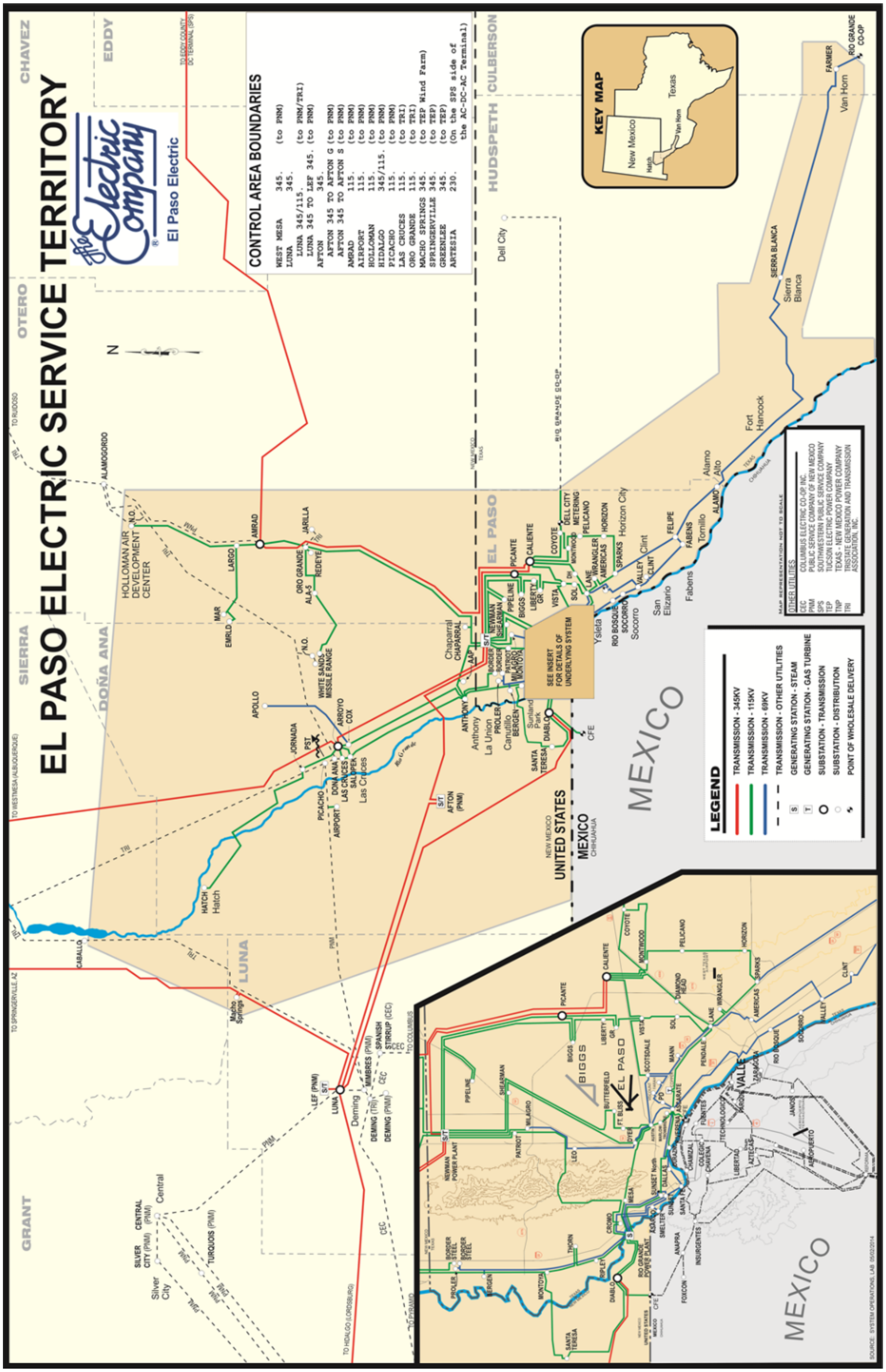


FIGURE 2. EPE's Electric Service Territory

VI. DESCRIPTION OF EXISTING RESOURCES

The IRP Rule requires that EPE provide a detailed description of its existing supply-side and demand-side resources used to serve its jurisdictional retail load at the time the IRP is filed, including:

1) Name and location(s) of utility-owned generation facilities;
2) Rated capacity of utility-owned generation facilities;
3) Fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the planning period;
4) Cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;
5) Existing generation facilities' expected retirement dates;
6) Amount of capacity obtained or to be obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;
7) Estimated in-service dates for utility-owned generation facilities for which a CCN has been granted but which are not in-service;
8) Amount of capacity and, if applicable, energy, provided annually to the utility pursuant to wheeling agreements and the duration of such wheeling agreements; and
9) Description of existing demand-side resources, including (1) demand-side resources deployed at the time the IRP is filed; and (2) demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed;

A. SUPPLY-SIDE RESOURCES

EPE satisfies the bulk of its customers' electrical demands with power generated from its generating stations fueled by natural gas, coal, and uranium. In addition, EPE purchases varying amounts of firm and non-firm energy through the wholesale markets to meet the needs of its customers. Included in these purchases are Purchased Power Agreements ("PPAs") for renewable energy.

1. EPE's Generating Facilities

EPE owns and operates a fleet of local and remote generating units. The Rio Grande Power Plant (“Rio Grande”), Newman Power Plant (“Newman”), Montana Power Station (“Montana”), and Copper Power Plant (“Copper”) are all located in EPE's service area within or near the City of El Paso, Texas. These generating stations are considered EPE's local generation. In addition, EPE owns five small solar photovoltaic ("PV") systems, one located at the Rio Grande Generating Station and another at the Newman Generating Station, the third located near Wrangler Substation in east El Paso, the fourth located at the El Paso Community College - Valle Verde Campus in El Paso's Lower Valley and the fifth system located on the rooftop of EPE's headquarters in downtown El Paso. These volunteer renewable energy projects have no costs allocated to New Mexico.

The Palo Verde Nuclear Generating Station ("PVNGS"), located near Phoenix, Arizona, and the Four Corners Power Plant ("FCPP"), located near Farmington, New Mexico, are considered EPE's remote generation. EPE owns 15.8 percent of the PVNGS' Units 1, 2 and 3; and owns seven percent of FCPP' Units 4 and 5. EPE will not be participating in or receiving power from FCPP after July 6, 2016. . EPE’s prior IRPs planned for the end of the 50-year terms of FCPP participation in July 2016. EPE has filed a regulatory proceeding for approval of the sale of EPE’s ownership to

Arizona Public Service Company.

EPE's existing generating stations and fuel types are listed in TABLE 4 below, together with in-service and currently planned retirement dates. As can be seen, the majority of EPE's generating facilities have been in service for a significant number of years. Additional data required by the IRP Rule is provided in ATTACHMENT A.

TABLE 4. EPE Owned Existing Generation Stations and Fuel Types

Generating Station	Location	Nominal Capacity (MW)	Primary Fuel Type	Secondary Fuel Type	In-Service Date	Projected Retirement Date
PVNGS Unit 1 Unit 2 Unit 3	Phoenix, AZ	633	Uranium	N/A	February1986 September1986 January 1988	June 2045 April 2046 November 2047
FCPP Unit 4 Unit 5	Farmington, NM	108	Coal	N/A	June 1969 July 1970	July 2016 July 2016
Montana Unit 1 Unit 2	El Paso, TX	176	Natural Gas	Fuel Oil	March 2015 March 2015	December 2055 December 2055
Rio Grande Unit 7 Unit 8 Unit 9	Sunland Park, NM	276	Natural Gas	N/A	June 1958 July 1972 May 2013	December 2020 December 2027 December 2058
Newman Unit 1 Unit 2 Unit 3 Unit 4 Unit 5	El Paso, TX	752	Natural Gas	Fuel Oil Units 1-3	May 1960 June 1963 March 1966 June 1975 May 2009 CTs April 2011 CC	December 2022 December 2023 December 2024 December 2025 December 2050
Copper Unit 1	El Paso, TX	64	Natural Gas	N/A	July 1980	December 2030

Newman Solar PV System 1	El Paso, TX	<1	N/A	N/A	December 2009	December 2029
Rio Grande Solar PV System 1	Sunland Park, NM	<1	N/A	N/A	December 2009	December 2029
Small Solar Systems	El Paso, TX	<1	N/A	N/A	4Q 2011	December 2032

NOTE: The unit retirement dates included above reflect EPE's current plan and are incorporated in the resulting STRATEGIST Base Case Resource Plan.

EPE has received approval in Case No. 13-00297-UT for construction of Montana Units 3 and 4. Montana Units 3 and 4 are expected to come online in May and December of 2016, respectively.

TABLE 5 summarizes the percentage contribution of nuclear fuel, natural gas, coal, purchased power and renewable purchased power to EPE's existing energy mix. Energy generated by the wind turbines and Company-owned solar generation accounted for less than 1 percent of the 2014 total kWh energy mix.

TABLE 5. Existing Percentage Contribution to EPE Energy Mix

POWER SOURCE	2014
Nuclear Fuel	47%
Natural Gas	35%
Coal	5%
Purchased Power	11%
Renewable Purchased Power	2%
Company-Owned Renewable	<1%
Total	100%

EPE's nuclear and coal units provide base load capacity at relatively low fuel costs. Approximately 52 percent of the Company's 2014 energy mix is provided by generation from PVNGS and FCPP.

PVNGS Unit 3 is decertified and deregulated for New Mexico jurisdictional purposes, but if used to serve New Mexico retail customers' load will be priced at an approved a proxy market price.

In May 2013 EPE completed construction of Rio Grande Unit 9 and in March 2015, EPE completed construction of Montana Units 1 and 2. Rio Grande Unit 9 and Montana Units 1 and 2 are natural gas aero-derivative units used primarily for system peaking/intermediate, but can also be used for load following. Rio Grande Unit 9 and Montana Units 1 and 2 provide a total capacity of up to 263 MW.

EPE's local generation serves three primary purposes. First, generation from EPE's local fleet is necessary to meet customer power needs during periods of high demand and to "follow" load as customer demand changes. Second, local generation provides load-serving reliability in the event that transmission constraints affect EPE's ability to import lower cost remote generation. Third, EPE's local generating units provide voltage support (i.e., reliability) throughout EPE's system in conjunction with the import of low-cost remote generation.

TABLE A-01, under ATTACHMENT A, contains a TABLE which lists annual capacity factors, fuel costs, heat rates, fixed and variable operating and maintenance ("O&M") costs projections for utility-owned generation facilities over the planning period. TABLE A-02 contains projected purchased power costs and TABLE A-03 contains present emission rates for effluents such as Nitrogen-Oxides ("NO_X"), Carbon Dioxide ("CO_2"), Carbon Monoxide ("CO") mercury ("Hg"), Sulfur Dioxide ("SO_2") and water consumption rates for each of EPE's local and remote existing generating units.

Two small solar projects to be located on military land are pending Commission approval. One is a

20 MW Ft. Bill facility pending in Case No. 15-00099-UT. The second is a 5MW Holloman Air Fore Base facility pending in Case No. 15-00185-UT. EPE has sought expedited approval of both facilities to be in service in 2016 prior to the termination of the current 30 percent federal investment tax credit applicable to these renewable energy resources. Because CCNs have not been approved and there is not an immediate capacity need for these resources, they are not included in the IRP base case resource portfolio.

2. EPE's Purchased Power Resources

In addition to relying on its own generating facilities, EPE also relies on resources acquired from wholesale suppliers or other sources. EPE has the following current long-term purchase power agreements in place to serve its customers:

- A 20-year PPA to purchase 20 MW of energy from a solar thermal facility developed by NRG, located in Santa Teresa, New Mexico. The contract is with NRG Solar Roadrunner, LLC. This facility came on-line on August 29, 2011. This contract provides solar renewable energy to EPE's customers and was approved for EPE's New Mexico RPS requirement.
- A 20-year PPA, expiring 2028, with Southwest Environmental Center ("SWEC") for energy and RECs from its 6 kW PV facility in Las Cruces, New Mexico. EPE uses the RECs for approved New Mexico RPS requirements.
- A 25-year PPA with Hatch Solar Energy Center 1, LLC for energy and RECs from a 5 MW concentrated solar PV facility developed by NextEra and located in Hatch, New Mexico which came on-line on July 8, 2011. EPE uses the RECs for approved New Mexico RPS requirements.

- A 25-year PPA with SunE EPE1, LLC for energy and RECs from a 10 MW solar PV facility located in Chaparral, New Mexico which came on-line on June 25, 2012. EPE uses the RECs for approved New Mexico RPS requirements.
- A 25-year PPA with SunE EPE2, LLC for energy and RECs from a 12 MW solar PV facility located in Las Cruces, New Mexico which came on-line on May 2, 2012. EPE uses the RECs for approved New Mexico RPS requirements.
- A 20-year PPA with Macho Springs Solar, LLC ("Macho Springs") for energy and RECs from a 50 MW solar PV facility located in Luna County, New Mexico which came on-line May 23, 2014.Although approved as a system resource, EPE uses the RECs associated with its New Mexico allocation of energy for New Mexico RPS requirements.
- A 30-year PPA with PSEG Solar for energy and RECS from a 10 MW solar PV facility located in El Paso, Texas which came on-line on December 30, 2014. PSEG is a Texas only jurisdiction resource.

EPE also has interconnected with its system a biomass energy Qualifying Facility ("QF"), Camino Real Landfill Gas to Energy Facility (1 MW), located in Sunland Park, New Mexico (at the Camino Real Landfill). Additionally, EPE offers QF net metering and REC programs for customer-owned solar PV and wind generation. The resulting customer-generated energy is used first to supply that customer's own needs and if excess energy is produced, it is delivered to EPE's system. The RECs obtained through these Commission-approved programs are used to meet New Mexico RPS requirements.

B. DEMAND-SIDE RESOURCES

EPE incorporates demand-side resources into its planning process. EPE has offered energy efficiency programs in its Texas service territory since 1999. EPE's Texas jurisdictional programs, which require minimum demand reductions, were developed as a result of retail electric restructuring legislation passed by the Texas Legislature in 1999. In New Mexico, the EUEA and the Commission's Energy Efficiency Rule, 17.7.2 NMAC, require utilities to include cost effective energy efficiency and load management programs in their resource portfolios. The EUEA requires EPE to attain a minimum energy savings goal of five percent of its 2005 New Mexico jurisdictional retail sales in 2014, and eight percent of the 2005 sales in 2020. EPE has received Commission approval to offer energy efficiency and load management programs for its New Mexico retail customers in NMPRC Case No. 07-00411-UT, Case No. 09-00390-UT, Case No. 11-00047-UT, and Case No. 13-00176-UT. TABLE 6 below provides EPE's New Mexico portfolio of programs and their Estimated Useful Life.

TABLE 6. EPE's Portfolio of Programs

New Mexico Energy Efficiency Programs 2015	
PROGRAM	**ESTIMATED USEFUL LIFE**
Residential Programs	
LivingWise®	12
Home Efficiency	17.84
Residential CFL & LED	6.73
High Efficiency Cooling	15.00
Appliance Recycling	5
ENERGY STAR® New Homes	23.00
EnergySaver (Low Income)	15.17
Commercial Programs	
Schools and Business Assistance	14.8
Small Business Comprehensive	11.54

EPE implemented its New Mexico CFL Lighting Program and its LivingWise® education program in late 2008. In addition, it formally implemented the remainder of its initial New Mexico programs in January 2009. EPE currently offers the following Commission-approved residential programs: LivingWise® Program, Home Efficiency Program, Residential CFL & LED Program, High Efficiency Cooling Program, Appliance Recycling Program, EnergySaver Program, and ENERGY STAR® New Homes Program. EPE also offers two commercial programs referred to as the Schools and Business Assistance Program and the Small Business Comprehensive Program. In 2014, EPE achieved 110 precent of the cumulative statutory goal of 65,815,596 kWh.

TABLE 7. Verified and Five-Year Projected Participation, Impacts and Budget Portfolio

Year	Annual Participants	Annual MW Demand Savings (at Meter)	Annual MWh Energy Savings (at Meter)	Annual Rebate/ Incentive Costs	*Annual Admin Costs	Total Annual Program Costs
2013♦	39,515	2.793	12,833	$2,308,781	$3,203,947	$3,259,172
2014♦	43,911	4.812	20,692	$3,606,015	$1,355,381	$4,961,396
2015	47,964	4.514	19,326	$3,702,423	$1,833,123	$5,535,546
2016	51,640	4.347	17,922	$3,639,321	$2,112,115	$5,751,436
2017	51,640	4.347	17,922	$3,639,321	$2,112,115	$5,751,436
2018	51,640	4.347	17,922	$3,639,321	$2,112,115	$5,751,436
2019	51,640	4.347	17,922	$3,639,321	$2,112,115	$5,751,436

* Includes Third Party Costs, Promotion Costs, Program Development Costs, and EM&V Costs
♦ Verified by Commission approved statewide EM&V contractor

TABLE 7 provides the actual verified savings for 2013 and 2014 and the five-year projections (2015-2019) for EPE's Energy Efficiency Programs. The 2015-2016 projections are based on the as-filed numbers in NMPRC Case No. 13-00176-UT. The 2017-2019 projections are based on the 2016 numbers filed in that docket. The gross MW and MWh projections don't include a peak demand coincidence factor that is used for forecasting purposes.

C. RATES AND TARIFFS

EPE's New Mexico base rates are designed to recover 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. The base rates also include a fuel and purchased power cost component, with any over or under-collection of actual fuel expenses passed through a

Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") on a monthly basis, in accordance with NMPRC Rule 550 requirements. EPE's approved tariff schedules offer a variety of options to customers, including time-of-use ("TOU") alternatives that are intended to encourage customers to shift energy use to off-peak periods.

EPE's New Mexico Rate Structures Promoting Energy Efficiency and Conservation

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

Modifications to Block Rates – EPE has eliminated all declining block rates. Further, the current Residential Service Rate contains an inclining block structure with a higher price for additional usage above 600 kWh per month during the months of May through October, which combined with a seasonal rate structure helps encourage greater energy efficiency during the summer months.

TOU Rates – Tariff schedules with a TOU rate option are the Residential Service, General Service, Irrigation Service and Military Research & Development Rates. The standard Large Power Service and State University Service rates are TOU rates. TOU rates contain price differentials between kWh during on-peak and off-peak hours to send more accurate price signals by more accurately targeting consumption during specific peak hours. TOU price differentials were designed to influence significant 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 Options – EPE offers an Instantaneous Interruptible Rate and Noticed Interruptible Rate option for large commercial, industrial and institutional customers.

EPE's current rates were implemented pursuant to the Final Order in NMPRC Case No. 09-00171-UT. The price signals contained in the current rate structures are intended to encourage energy efficiency, energy conservation and load shifting by customers. The price signals specifically target the afternoon hours of the summer months, when EPE's system peaks. These higher prices during on-peak periods are intended to encourage 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 should decrease EPE's summer peak, which will help reduce or delay new resource additions.

EPE has filed its Application for Revision of Retail Electric Rate (Case No. 15-00127-UT), and has proposed changes to existing rates and rate structures to further conservation and energy efficiency and to incentivize customers to shift usage and reduce contributions to EPE peak demand. The proposed are noted below.

EPE's Current Non-Lighting New Mexico Rates

Residential Service Rate – Rate consists of a fixed monthly customer charge and a seasonal, inclining block summer energy charge for usage over 600 kWh. The summer months are May through October.

Residential Service TOU Rate – Rate consists of a fixed monthly customer charge and an On-Peak/Off-Peak price differentiated energy charge. The rate discourages consumption from 12:00 pm to 8:00 pm on all weekdays, for the summer months of May through October.

Small Commercial Service, Alternative Monthly Rate (Non-Demand) – Rate consists of a fixed monthly customer charge and a seasonal energy charge. The summer months are May through October. This rate is applicable to customers with less than 7,000 kWh or 15 kW during any billing month.

Small Commercial Service Rate (Demand < 50 kW) and General Service Rate (Demand Between 50 – 799 kW) – Rates consist of a fixed monthly customer charge, a demand charge and a seasonal energy charge. The summer months are May through October.

General Service TOU Rate – Rate consists of a fixed monthly customer charge and an On-Peak/Off-Peak price differentiated energy charge. The rate discourages consumption from 12:00 pm to 6:00 pm on all weekdays, for the summer months of June through September. EPE has proposed to modify the existing rate structure to seasonalize the demand charge, with a higher charge applying in the peak summer months.

Irrigation Service Rate – Rate consists of a fixed monthly customer charge and a seasonal energy charge. The summer months are May through October.

Irrigation Service TOU Rate – Rate consists of a fixed monthly customer charge and seasonal energy charge, with an optional TOU On-Peak/Off-Peak price differentiated energy charge. The rate discourages consumption from 1:00 pm to 5:00 pm on all weekdays, for the summer months of June through September. EPE is proposing that the TOU rate now be mandatory for all new Irrigation service customers.

City and County Service Rate – Rate consists of a fixed monthly customer charge, a demand charge and a seasonal energy charge. The summer months are May through October.

This rate is closed to new customers, and EPE has proposed its elimination in the pending rate case. All existing customers would be moved to the applicable commercial rate with TOU options.

Water, Sewage, Storm Sewage Pumping or Sewage Disposal Service Rate – Rate consists of a fixed monthly customer charge and a seasonal energy charge. The summer months are June through September. EPE is proposing a new TOU option for customers served on this rate schedule.

Large Power Service Rate (Demand > 799) – Rate consists of a customer charge, a demand charge and an On-Peak/Off-Peak price differentiated energy charge. The rate discourages consumption from 12:00 pm to 6:00 pm on all weekdays, for the summer months of June through September. EPE is proposing to seasonalize the existing demand charge, with a higher charge applying in the peak summer months.

Military Research and Development Power Rate – Rate consists of a fixed monthly customer charge, a demand charge and a flat non-seasonal energy charge and an optional On-Peak/Off-Peak price differentiated energy charge. EPE has proposed to replace the existing rate structure with one that mimics the proposed Large Power Service rates, which combines a monthly customer charge, TOU energy and seasonal demand charges.

Seasonal Agriculture Processing Service Rate – Rate consists of a fixed monthly customer charge and a seasonal energy charge. The summer months are June through September.

State University Service Rate – Rate consists of a fixed monthly customer charge and an On-Peak/Off-Peak price differentiated energy charge. The rate discourages consumption from 12:00 pm to 6:00 pm on all weekdays, for the summer months of June through September. EPE has proposed to replace the existing rate structure with one that mimics the proposed Large Power Service rates, which combines a monthly customer charge, TOU energy and seasonal demand charges.

Instantaneous Interruptible Service Rate (Demand > 1,000 kW) – Rate consists of a demand charge and a flat non-seasonal energy charge in conjunction with Large Power Service Rate. Requires a 3-year contract and must be able to curtail at least 500 kW. Customers must interrupt immediately upon notification, and are subject to interruption up to 400 hours per year. This rate provides a capacity resource to EPE and reduces peak capacity requirement. The tariff structure has proved unpopular and EPE is proposing to eliminate this rate option for lack of interest.

Noticed Interruptible Service Rate (Demand > 1,000 kW) – Rate consists of a demand charge and a flat non-seasonal energy charge in conjunction with Large Power Service Rate. Requires a 3-year contract and must be able to curtail at least 500 kW. Customers receive a 30 minute interruption notice, and are subject to interruption up to 400 hours per year. This rate provides a capacity resource to EPE and reduces peak capacity requirement. This rate is closed to new customers.

Voluntary Renewable Energy Rate – Rate allows customers to purchase 100 kWh blocks of renewable energy.

Small System, Medium System and Large System REC Purchase Tariffs – Program provides incentives for installation of photovoltaic or wind generation QFs. Energy is net metered. The QF reduces the amount of energy supplied by EPE to the customer. EPE obtains required RECs to help meet its RPS and diversity requirements.

EPE's Proposed Demand Response Program

In EPE’s current rate case, Case No. 15-00127-UT, EPE is proposing cost deferral for later recovery of an RFP process to initiate a pilot program to gauge the acceptance and efficacy of demand response utilizing programmable or "smart" thermostats to target air conditioning load. Demand Response ("DR") is a proposed voluntary program that engages utility customers to reduce their electricity use (load) during peak hours or under certain conditions. Peak electricity demand typically occurs on hot summer days when households turn on their air conditioning (A/C). Fundamentally, the main goal of the demand response program is to reduce A/C usage on hot summer days, which in turn, can substantially reduce demand for electricity during peak hours, providing aggregate benefits for the electric grid and households themselves.

EPE’s residential and small commercial customers will be eligible to participate in the pilot DR program. During the term of the pilot, EPE expects to offer up to 3,000 customers the opportunity to participate in the DR program subject, to the ultimate cost and authorization by the Commission.

EPE proposes to develop a program that is fully automated and which does not depend upon customer action. To accomplish this goal, EPE intends to implement a DR program which leverages smart thermostat capabilities. The exact conditions of the program will be a function of the offerings of selected third-party vendors.

EPE expects that load curtailment would be accomplished through a combination of continuous monitoring and adjustment of thermostats during the cooling season as well as more dramatic adjustments for short intervals as targeted curtailments. EPE proposes to contract with one or more vendors to market, operate, and monitor the program. EPE will also separately meter and analyze demand response by participants to measure load reductions and validate data reports provided by the third-party vendors. If the data supports energy efficiency cost effectiveness requirements, EPE could propose such a program as part of an energy efficiency measure or program.

VII. TRANSMISSION RESOURCES AND CAPABILITY RATINGS

EPE owns and operates extensive transmission resources to serve its load from its local generation, remote generation in Arizona and New Mexico, (PVNGS and FCPP) and from other interconnected resources throughout WECC. EPE's high voltage ("HV") transmission system used in the delivery of power to its customers consists of 69 kV, 115 kV, 345 kV, and 500 kV transmission lines that are located within the EPE service territory, interconnected to the western grid, or located near EPE's remote generation. EPE's 345 kV system is the integral part of the transmission system used to import and export power to and from the El Paso area and is comprised of three key components:

- Several 345 kV transmission lines that are interconnected within EPE's electrical grid.
- Three major 345 kV transmission lines known as Path 47 used to import/export power between WECC and EPE; and,
- A single 345 kV transmission line that interconnects EPE's local transmission system to SPS, an Xcel Energy Company, system through a 200 MW HVDC terminal.

More details on EPE's transmission system are explained below.

EPE's major 345 kV transmission interconnections with other utilities are at the (1) West Mesa Switching Station near Albuquerque, New Mexico with PNM; (2) Springerville Generating Station and Greenlee Substation (both in Arizona) with Tucson Electric Power Company ("TEP"); and (3) Eddy County HVDC Terminal near Artesia, New Mexico with SPS. EPE also has a partial ownership interest in three 500 kV transmission lines in Arizona, from the PVNGS switchyard to the 500 kV Kyrene and the 500 kV Westwing substations in the Phoenix area.

EPE's local HV transmission system consists of 115 kV and 69 kV lines in and around El Paso, Texas and Las Cruces, New Mexico. For the most part, each major substation in the EPE system is connected by at least two 115 kV 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.

To access and deliver PVNGS and FCPP power, EPE utilizes a combination of an exchange agreement with TEP, a Power Purchase and Sale Agreement between EPE and Phelps Dodge Energy Services, LLP (now Freeport-McMoRan), transmission wheeling purchased from TEP, Salt River Project ("SRP") and PNM, and the 345 kV transmission systems in southern New Mexico. Once the power is on EPE's 345 kV system, it is delivered to EPE's local high voltage transmission system through EPE's existing 345/115 kV auto-transformers. Once on the local 115 kV transmission system, the power is distributed to EPE local customers through substations that step the voltage down to the distribution voltage level and out across the EPE distribution system.

As mentioned previously, after July 2016, EPE will no longer be participating in the FCPP. There will be no impact on EPE’s import capability since the FCPP and EPE’s firm capacity rights over PNM’s Path 48 are independent of each other. EPE needs to maintain 124MW of firm capacity rights over PNM’s Path 48 to maintain its maximum firm Southern New Mexico Import Capability (SNMIC). These transmission rights over Path 48 are then utilized by EPE to import power through EPE’s interconnection with PNM at West Mesa. EPE assures its ability to import firm capacity at

West Mesa by acquiring firm transmission rights from PNM from Four Corners to West Mesa on Path 48.

EPE's local generation is directly connected to the local HV transmission system at the Newman Generating Station in northeast El Paso; the Rio Grande Generating Station in Sunland Park, New Mexico; and the Copper Generating Plant 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. FIGURE 3 below diagrams EPE's HV transmission line segments.

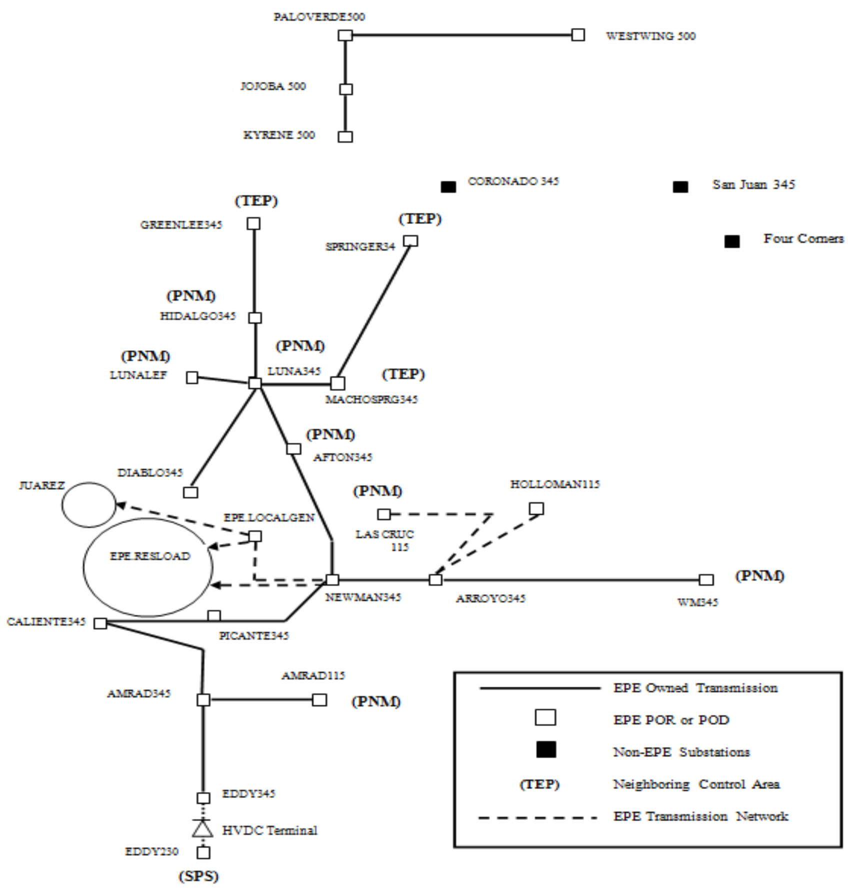


FIGURE 3. Segments Which Comprise the EPE High Voltage Transmission System

A description of the EPE electrical system of 115 kV and above, including existing and under-construction transmission facilities in Texas and New Mexico is provided in Section A below.

A. EXISTING AND NEW EPE TRANSMISSION FACILITIES

EPE's transmission facilities include transmission lines (internal and external to EPE), substation transformers, autotransformers and a Phase Shifting Transformer ("PST") at Arroyo Substation. The Arroyo PST is currently out of service and EPE expects to replace it by the end of 2015. EPE owns and operates 226 miles of 69 kV transmission lines, 591 miles of existing 115 kV transmission lines and 945 miles of 345 kV transmission lines. In addition, EPE jointly owns 165 miles of 500 kV transmission lines in Arizona.

TABLES 8 through 12 below provide transmission facility data, including lengths, and MVA capacities. This information presents internal transfer capability limitations (ratings) on EPE's transmission network that may affect future siting of supply-side resources. TABLE 8 lists transmission facilities under construction.

TABLE 8. Existing EPE Transmission Lines 115 kV and Above

EL PASO ELECTRIC COMPANY								
Existing 115 kV and Above Internal Lines				RATING		LENGTH	STATE LOCATION	
From	To	kV	Circuit	MVA Normal	MVA Emerg	Miles	From	To
AMRAD	ARTESIA	345	1	220	220	125.4	NM	NM
CALIENTE	AMRAD	345	1	785	785	56.0	TX	NM
CALIENTE	PICANTE	345	1	789	789	7.3	TX	TX
HIDALGO	GREENLEE	345	1	812	812	60.0	NM	AZ
LUNA	AFTON	345	1	939	939	57.3	NM	NM
LUNA	DIABLO	345	1	939	939	84.2	NM	NM

LUNA	HIDALGO	345	1	705	705	50.5	NM	NM
MACHO_SPRNGS	LUNA	345	1	1040	1390	24.9	NM	NM
MACHO SPRINGS	SPRINGERVILLE	345	1	727	727	201.4	NM	AZ
NEWMAN	ARROYO	345	1	782	782	30.3	TX	NM
NEWMAN	AFTON	345	1	1028	1028	29.9	TX	NM
PICANTE	NEWMAN	345	1	787	787	16.2	TX	TX
WESTMESA	ARROYO	345	1	681	681	201.8	NM	NM
AIRPOR_T	AIRPOR	115	1	153	153	2.7	NM	NM
ALA_5	ORO_GRAN	115	1	69	69	9.8	NM	NM
AMRAD	LARGO	115	1	113	113	7.7	NM	NM
ANTHONY	ARROYO	115	1	155	207	24.4	NM	NM
ANTHONY	BORDER	115	1	207	207	5.2	NM	TX
ANTHONY	SALOPEK	115	1	155	207	17.3	NM	NM
ANTHONY	NEWMAN	115	1	199	199	12.3	NM	TX
ANTHONY	TRANSMTN	115	1	155	207	10.2	NM	TX
ASCARATE	TROWBRIG	115	1	127	171	0.5	TX	TX
ASCARATE	COPPER	115	1	173	233	1.4	TX	TX
AUSTIN_N	MARLOW	115	1	126	169	1.2	TX	TX
BIGGS	IND_COMP	115	1	173	233	2.4	TX	TX
BUTERFLD	FT._BLIS	115	1	127	169	1.9	TX	TX
CALIENTE	DIAMOND_HEAD	115	1	157	219	6.0	TX	TX
CALIENTE	MPS	115	1	59	81	8.7	TX	TX
CALIENTE	MPS	115	2	162	353	2.5	TX	TX
CALIENTE	MPS	115	3	162	353	2.5	TX	TX
CALIENTE	VISTA__#	115	1	207	208	6.6	TX	TX
CHAPARAL	ORO_GRAN	115	1	155	155	35.4	NM	NM
COPPER	PENDALE	115	1	118	159	5.0	TX	TX
COYOTE	RGC_DC	115	1	19	19	75.3	TX	TX
CROMO	RIO_GRAN	115	1	127	169	0.9	TX	TX
DIABLO	RIO_GRAN	115	1	287	391	2.9	NM	TX
DIABLO	RIO_GRAN	115	2	287	391	2.9	NM	NM
DIAMOND_HEAD	LANE___#	115	1	157	219	2.6	TX	TX
DURAZNO	ASCARATE	115	1	127	169	3.3	TX	NM
DYER	SHEARMAN	115	1	127	169	9.6	TX	TX
DYER	AUSTIN_N	115	1	173	233	2.1	TX	TX
FT._BLIS	AUSTIN_N	115	1	127	169	1.8	TX	TX
GR	VISTA__#	115	1	142	195	3.0	TX	TX
HATCH	JORNADA	115	1	39	39	33.4	NM	NM
HOLLOMAN	LARGO	115	1	113	113	14.9	NM	NM
JORNADA	ARROYO	115	1	74	74	4.9	NM	NM

JORNADA	AIRPOR	115	1	173	233	16.5	NM	NM
LANE___#	WRANGLER	115	1	155	207	1.0	TX	TX
LAS_CRUC	ARROYO	115	1	155	207	4.1	NM	NM
LAS_CRUC	SALOPEK	115	1	155	207	5.0	NM	NM
LIBERTY_	GR	115	1	173	233	2.6	TX	TX
MAR	LARGO	115	1	23	23	11.4	NM	NM
MARLOW	TROWBRIG	115	1	113	138	1.1	TX	TX
MESA___#	AUSTIN_N	115	1	155	207	6.1	TX	TX
MESA___#	RIO_GRAN	115	1	142	204	2.2	TX	NM
MILAGRO	NEWMAN	115	1	173	233	6.3	TX	TX
MONTWOOD	CALIENTE	115	1	173	233	5.0	TX	TX
MONTWOOD	COYOTE	115	1	173	233	7.8	TX	TX
MPS	COYOTE	115	1	162	353	2.9	TX	TX
MPS	MONTWOOD	115	1	162	353	6.0	TX	TX
NEWMAN	CHAPARAL	115	1	127	169	2.9	TX	NM
NEWMAN	BUTERFLD	115	1	127	169	16.7	TX	TX
NEWMAN	SHEARMAN	115	1	127	169	7.3	TX	TX
NEWMAN	PIPELINE	115	1	173	233	9.8	TX	TX
NEWMAN	PICANTE	115	1	173	233	13.6	TX	TX
ORO_GRAN	AMRAD	115	1	155	155	7.9	NM	NM
PATRIOT	NEWMAN	115	1	127	169	2.2	TX	TX
PATRIOT	CROMO	115	1	127	169	17.7	TX	TX
PELICANO	HORIZON	115	1	142	195	6.7	TX	TX
PELICANO	MONTWOOD	115	1	173	233	3.8	TX	TX
PENDALE	LANE___#	115	1	118	159	1.5	TX	TX
PICANTE	GR	115	1	173	233	6.0	TX	TX
PICANTE	BIGGS	115	1	173	233	2.3	TX	TX
PIPELINE	BIGGS	115	1	127	169	13.6	TX	TX
RIO_GRAN	RIPLEY	115	1	155	207	3.0	NM	TX
RIPLEY	THORN	115	1	127	169	1.9	TX	TX
SALOPEK	ARROYO	115	1	127	169	10.7	NM	NM
SANTA_T	MONTOYA	115	1	173	233	7.4	NM	TX
SANTA_T	DIABLO	115	1	155	207	8.9	NM	NM
SCOTSDALE	VISTA__#	115	1	127	169	5.2	TX	TX
SOL	LANE___#	115	1	127	169	2.1	TX	TX
SOL	VISTA__#	115	1	127	169	2.0	TX	TX
SPARKS	HORIZON	115	1	173	233	3.8	TX	TX
SUNSET_N	DURAZNO	115	1	127	169	4.6	TX	TX
SUNSET_N	RIO_GRAN	115	1	235	319	5.1	TX	NM
THORN	MONTOYA	115	1	127	169	3.0	TX	TX
TRANSMTN	MONTOYA	115	1	155	207	5.2	TX	TX

WHITE_SA	ALA_5	115	1	69	69	13.0	NM	NM
WRANGLER	SPARKS	115	1	85	116	4.0	TX	TX

- "Internal" refers to lines within EPE's native system including lines connecting EPE to neighboring utilities, however, not including line segments partially owned by EPE external to EPE's control area.
- The ratings are generally based on conductor thermal capacities but may be derated due to sag limitations or other factors.
- The lines colored in yellow above are part of path 47 which includes the Belen to Bernardo 115 kV line owned by TriState.
- RGC_DC is Rio Grande Electric Cooperative, Dell City.
- ALA_5 is Army Launching Area 5.

TABLE 9. Existing 115 kV EPE Substation Transformers

EL PASO ELECTRIC COMPANY				
Existing 115 kV Load & Step-up Substation Transformers		RATING Normal MVA	Emergency MVA	State
AIRPORT	115/23.9	34	39	NM
AMRAD	115/24.9	8	9	NM
ANTHONY	115/23.9	34	39	NM
ANTHONY	115/23.9	34	39	NM
ARROYO	115/23.9	67	77	NM
AUSTIN NORTH	115/13.8	50	58	TX
AUSTIN NORTH	115/13.8	50	58	TX
BUTTERFIELD	115/13.8	30	32	TX
BUTTERFIELD	115/13.8	30	35	TX
CALIENTE	115/13.8	34	39	TX
CHAPARAL	115/13.8	34	39	NM
CHAPARAL	115/13.8	34	39	NM
COPPER	115/13.8	30	32	TX
COPPER_G	13.8/115	75	86	TX
COYOTE	115/13.8	30	35	TX
CROMO	115/13.8	30	35	TX
CROMO	115/13.8	30	35	TX
DIAMOND HEAD	115/13.8	34	39	TX
DURAZNO	115/13.8	34	39	TX
FT. BLISS	115/13.2	105	111	TX
GLOBAL REACH	115/13.8	30	34	TX

HATCH	115/24.9	30	32	NM
HORIZON	115/13.8	34	39	TX
JORNADA	115/23.9	67	77	NM
LANE	115/13.8	50	57	TX
LAS_CRUCES # 1	115/23.9	67	77	NM
LAS_CRUCES # 2	115/23.9	67	77	NM
MAR	115/4.2	10	11	NM
MESA # 1	115/13.8	30	32	TX
MESA # 2	115/13.8	30	32	TX
MILAGRO	115/13.8	34	39	TX
MILAGRO	115/13.8	34	39	TX
MILAGRO	115/13.8	34	39	TX
MONTOYA	115/24.9	34	39	TX
MONTOYA	115/23.9	50	56	TX
MONTOYA	115/23.9	50	56	TX
MONTWOOD	115/23.9	34	39	TX
MONTWOOD	115/23.9	34	39	TX
MPS	13.8/115	168	168	TX
MPS	13.8/115	168	168	TX
NEWMANG1	13.8/115	112	125	TX
NEWMANG2	13.8/115	112	125	TX
NEWMANG3	13.8/115	112	125	TX
NEWMN4G1	13.8/115	90	112	TX
NEWMN4G2	13.8/115	90	112	TX
NEWMN4S1	13.8/115	125	125	TX
NEWMN5G1	13.8/115	117	130	TX
NEWMN5G2	13.8/115	117	130	TX
NEWMN5S1	13.8/115	150	175	TX
PATRIOT	115/13.8	34	38	TX
PELICANO	115/23.9	34	39	TX
PENDALE	115/13.8	34	39	TX
PICACHO	115/24.9	50	56	NM
RIO GRAN_G9	13.8/115	132	152	NM
RIO GRAN_G8	17.5/115	168	193	NM
RIPLEY	115/13.8	67	77	TX
SALOPEK # 1	115/24.9	25	28	NM
SALOPEK # 2	115/24.9	25	28	NM
SALOPEK # 3	115/24.9	25	28	NM
SANTA TERESA 1	115/23.9	30	35	NM
SANTA TERESA 2	115/23.9	30	35	NM
SHEARMAN	115/13.8	30	32	TX

SOL # 1	115/13.8	30	32	TX
SOL # 2	115/13.8	30	32	TX
SPARKS	115/13.8	67	77	TX
SUNSET NORTH	115/13.8	30	33	TX
SUNSET NORTH	115/13.8	30	33	TX
THORN # 1	115/13.8	34	39	TX
THORN # 2	115/13.8	34	39	TX
TRANSMTN	115/23.9	67	77	TX
VISTA # 1	115/13.8	30	32	TX
VISTA # 2	115/13.8	30	32	TX
WHITE SANDS	115/13.8	30	32	NM
WRANGLER	115/13.8	50	58	TX

TABLE 10. EPE 345/115 kV Autotransformers

EL PASO ELECTRIC COMPANY				
Existing Auto Transformers 115 kV and Above	kV	RATING Normal MVA	Emergency MVA	State
AMRAD	345/115	290	333	NM
ARROYO #1	345/115	224	258	NM
ARROYO #2	345/115	224	258	NM
CALIENTE #1	345/115	224	258	TX
CALIENTE #2	345/115	224	258	TX
DIABLO #1	345/115	224	258	NM
DIABLO #2	345/115	224	258	NM
DIABLO #3	345/115	224	258	NM
NEWMAN	345/115	230	265	TX
PICANTE	345/115	224	258	TX

Note:

TABLE 11. EPE External Line Segments

EPE External Transmission Segments (Arizona)		EPE share of	EPE share of	TTC of PV East	
Point of Receipt	Point of Delivery	TTC (MW)	ATC (MW)	Path (MW)	Path Description
Palo Verde 500 kV Westwing 500 kV	Westwing 500 kV (1) Palo Verde 500 kV (2)	1034 * 1034 **	TTC-439 TTC-440-CST	7510 7510	Two line segment in which EE has an 18.7% ownership interest
Palo Verde 500 kV Jojoba 500 kV	Jojoba 500 kV (3) Palo Verde 500 kV (4)	555 555	TTC-203-CST TTC-CST	7510 7510	One line segment in which EE has an 18.7% ownership interest
Jojoba 500 kV Kyrene 500 kV	Kyrene 500 kV (3) Jojoba 500 kV (4)	1034 * 1034 **	TTC-203-CST TTC-CST	7510 7510	One line segment in which EE has an 18.7% ownership interest

Note: EPE's share of TTC on the Palo Verde East Path is 1034 MW

(1) EPE has retained 439 MW (AREF Set Aside) ATC for native load uses

(2) EPE has retained 400 MW (AREF Set Aside) ATC for use by TEP

(3) EPE has retained 203 MW (AREF Set Aside) ATC for native load uses

(4) At the present time, there are no Committed Uses on this segment

* TTC for PV East System

** TTC for PV East System in east to west direction

CST - Common Segment Transactions

TABLE 12. Under-Construction EPE Transmission Facilities

EL PASO ELECTRIC COMPANY			
Under Construction / Status *	Transmission Facility	Capability Ratings Norm MVA / Emer MVA	State
Pending Right-of-Way	Austin - Dyer 69 kV	93.9 / 131.3	TX
Under Construction	Lane - Copper 115 kV Line Reconductor	156.6 / 218.8	TX
Under Construction	Montoya Substation 115 kV Capacitor Bank	-	TX
Under Construction	Fabens Substation 69 kV Capacitor Bank	-	TX
Under Construction	Farmer Substation 69 kV Capacitor Bank	-	TX
Under Construction	Rio Bosque Substation 69 kV Capacitor Bank	-	TX

* Refers to the project status during the development of this filing.

EPE engages in various transmission projects to maintain, upgrade and expand EPE's transmission system in order to ensure the reliability of the system and to provide for future load growth. EPE produces a 10-year Transmission Expansion Plan ("Plan") every other year in accordance with Attachment K of EPE's Open Access Transmission Tariff ("OATT"). A summary of the Plan is posted on EPE's web site. TABLE 12 lists EPE transmission facilities currently under construction during the development of this New Mexico IRP filing.

B. TRANSMISSION OPERATION AND PLANNING STANDARDS

Although EPE is physically interconnected to the SPP through its HVDC tie, EPE's primary interconnection is to the WECC. EPE's ability to import its remote generation resources is limited by the transmission capacity of its WECC interconnection, termed WECC Path 47 or the Southern New Mexico Transmission System ("SNMTS"). EPE has transmission rights of 133 MW over the HVDC tie, up to 645 MW over Path 47, and 1,034 MW on EPE's external transmission lines interconnecting PVNGS.

Transmission service adheres to a standard set of priorities to avoid confusion. These priorities are:

- Firm service has priority over non-firm service;
- Pre-confirmed firm service has priority over non pre-confirmed firm service;
- Non-firm transfers, both reserved and scheduled, may be recalled for firm transfer requests.

In order to determine the amount of firm or non-firm energy that can be transferred over a transmission network, the maximum capabilities of the transmission lines, both individually and as combined for a given transmission path, must be established. The Total Transfer Capability ("TTC") of a transmission network is the maximum amount of power that can be transferred from one point on the system to another point on the system in a reliable manner while meeting all of 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 in the transmission network for commercial activity over and above already committed uses and established capacity and reliability margins. It is defined as TTC less existing transmission commitments (including retail customer service), less a capacity benefit margin, less a transmission reliability margin.

EPE and other utilities make these determinations on a real-time basis. TTC and ATC values are posted on the wesTTrans webOASIS for the EPE transmission system with all transmission lines in-service, and will change 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 in below.

Additional transmission data pertaining to EPE's transmission facility capability and planning standards required by the IRP Rule 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"). The ATC document explains EPE transmission facility capabilities and how EPE operates its New Mexico and Texas transmission system as a whole. This report also identifies and defines the transmission

planning and/or coordination groups that EPE partakes in while operating and planning its transmission system.

FERC Form No. 715, *"Annual Transmission Planning and Evaluation Report."* FERC Form No. 715 contains transmission planning reliability and operating criteria submitted by EPE System Planning to the Federal Energy Regulatory Commission ("FERC") used to develop and evaluate the transmission capabilities of the SNMTS as well as for maintaining EPE's internal (whole) transmission system reliability.

"*New Mexico Transmission System Operating Procedures*" ("NMTSOP"). The NMTSOP sets forth operating procedures followed by EPE, PNM, and Tri-State Generation and Transmission Association, Inc. ("Tri-State"). These procedures provide a basis for operation of the present SNMTS and the present Northern New Mexico Transmission System ("NNMTS") synchronously connected to the Western Interconnection under normal and emergency conditions.

1. SNMIC Determination

Total and available transmission capabilities for the primary 345 kV paths which connect the EPE control area to external control areas operated by PNM and TEP are based on the SNMIC. The individual lines into the EPE control area -- the WestMesa 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 path rating is defined by dynamic nomograms and, as a result, the ratings of the individual lines (paths) that make up Path 47 must be adjusted. For example, if the sum of the individual transmission path TTCs total

1,000 MW, but the Path 47 TTC is 500 MW, the individual transmission path TTCs must be reduced accordingly.

The SNMIC is determined through nomogram equations that incorporate the state and configuration of the system at any instant of time and by the use of dynamic adjustments that reflect changes in that system state. These dynamic adjustments reflect system variables such as: the status and output of EPE's and other local generating units, power factors for the underlying system, status of 345 kV reactors in the SNMTS, and the amount and direction of power flows over EPE's other 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, EPE is obligated to decrease its portion of SNMIC. For example, the maximum amount of firm import capability of 940 MW is modified under the above mentioned NMTSOP with the loss of the Arroyo PST to a value of 800 MW, with EPE's allocation reducing to 505 MW.

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.

2. TTC/ATC for EPE External Transmission Line Segments

EPE partially owns transmission line segments in the Arizona transmission system in connection with its PVNGS ownership and uses these line segments for the delivery of its owned Palo Verde generation entitlement. These transmission lines are designated as the Palo Verde East Path (composed of three line segments, the Palo Verde to Westwing line segment, the Palo Verde to Jojoba line segment and the Jojoba to Kyrene line segment) and are operated by Salt River Project. 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. A full explanation on how TTC and ATC on these paths are determined can be found in the ATC document in Attachment B.01.

C. TRANSMISSION PLANNING OR 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 Planning Committees under the Transmission Expansion Planning Policy Committee ("TEPPC"). These groups include the System Review Work Group ("SRWG"), the Technical Advisory Subcommittee ("TAS"), Variable Generation Subcommittee ("VGS"), the GE Users Group, and the subregional group WestConnect and its Southwest Area Transmission ("SWAT") Planning Committee.

Under the SWAT Planning Committee, EPE is a participating member of various sub-regional work groups including the New Mexico Work Group, the Arizona/New Mexico Work Group, the Southern Arizona Transmission Study Work Group and the Short Circuit Working Group. Through the WestConnect and SWAT planning groups, EPE and other members coordinate the planning process for the transmission system in the SWAT and WestConnect footprints. The SWAT footprint includes Arizona, New Mexico, Nevada, West Texas, and parts of California. The WestConnect footprint shadows the SWAT footprint and also includes Colorado, part of Wyoming, part of California, and part of Nebraska. Information on SWAT, WestConnect, and other WECC planning committees is available on the WECC website at http://www.wecc.biz and the WestConnect website at http://www.westconnect.com.

A description of the inter-relationship between the EPE planning process and the planning processes of WestConnect and SWAT is posted on EPE's website. Attachment B.02 of the ATC document also contains a geographic map of the EPE service territory including WECC maps of principal transmission lines and planned facilities through 2022 and possible transmission beyond the date as of January 1, 2012.

VIII. ENVIRONMENTAL CONSIDERATIONS

EPE evaluates potential impacts to environmental resources during planning efforts and when considering new development and maintenance and operations activities. In general the environmental considerations for siting renewable generation facilities, traditional 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.

The National Environmental Policy Act ("NEPA") mandates that all federal agencies consider the environmental impact of a proposed action and provides guidance as to how those impacts should be assessed. NEPA is applicable to any actions that are directly carried out by a federal agency or have a nexus to a federal action. In EPE's case, NEPA is frequently triggered by connected actions, for example the acquisition of transmission line right-of-way from a federal land management agency, or the need for an air permit from the Environmental Protection Agency for a new generation facility. In these cases a formal regulatory review process in engaged. Although not all EPE projects trigger NEPA, EPE uses the procedures which it prescribes as guidance for internal environmental review.

EPE environmental review is initiated upon demonstration of a purpose and need for a project. As described throughout this document, different alternatives, be they generation technologies, proposed locations, or routings that meet the project needs are identified for consideration. At that point, the existing environmental conditions of the proposed project areas are reviewed and a list of environmental resources that may be impacted by the proposal is assembled. Depending on the scope of the project, relevant regulatory agencies and /or potentially affected third parties may be consulted for their input at this stage of the environmental review. For each resource that may be impacted, the direct, indirect and cumulative effects of the proposed project are evaluated.

Impacts to air quality are evaluated against Clean Air Act regulations to determine suitability of a proposed technology and feasibility of permitting. For any project with potential emissions, ranging from the purchase of an emergency generator to installation of a new conventional generation unit, a New Source Review applicability test is conducted. During this review the 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. 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.

Biological resources include wildlife, avian, vegetation and habitat resources. 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 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.

EPE's service territory is rich with cultural resources. 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 or not there are cultural resources within a project's area of potential effect and whether or not those resources would be adversely affected. These determinations are made in consultation with the State Historic Preservation Officer and any appropriate 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 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.

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 are generally 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.

Air quality, water quality, and biological and cultural resources are the most frequently evaluated environmental parameters for EPE projects. However, there are numerous other resources that fall under the environmental umbrella. Although no less important, the following resources are also 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. 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.

IX. LOAD FORECAST

EPE's 2015 Load Forecast is developed from a number of 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, saturation of refrigerated air conditioning, and potential changes in customers.

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. 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, personal income, and weather are typical drivers of electricity sales; more customers and increased income to purchase appliances will typically result in higher electricity demand. The primary data source for these estimates is IHS Economics, which provides the underlying assumptions of the economic and demographic data that were used in developing EPE's forecasted energy and demand.

The 2015 Forecast employs monthly and annual methodologies to develop its models. 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 load sector in Texas and the large commercial & industrial and street lighting load sectors in New Mexico for a total of nine separate forecasts. Each of the nine models is estimated using Ordinary Least Squares as a function of weather, economic, and demographic variables. Residential energy sales are estimated using a use per customer (“UPC”) methodology. The estimated UPC is then multiplied by the customer forecast to arrive at a total kWh forecast for this customer class. The energy forecasts for small commercial & industrial, large commercial & industrial, street lighting, and government are estimated using total kWh. The final models are selected based on various key measures such as R2, t-statistics, the Durbin-Watson test, the F-statistic, and professional judgment.

Similarly, the 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. These two classes have a small number of customers, whose energy consumption and demand vary significantly among individual customers. The number of large commercial & industrial customers is set at current levels, unless it is known for certain that specific customers are planning to enter or leave the service territory at a future date. For these reasons, EPE chooses to maintain a customer count for these classes constant with 2014 year ending levels.

In instances where adequate data is not available to support statistical analyses, EPE relies on non-econometric sales estimates based upon professional judgment, recent experience, and information from large industrial customers. These are referred to as "out-of-model adjustments." EPE utilizes out-of-model adjustments that are based on known or expected changes in load not directly accounted for in the econometric models. Examples of these adjustments in the 2015 Load Forecast include distributed solar generation, changes in load at military installations, energy efficiency, and the retrofitting of street lighting in Texas with LED bulbs.

The econometric sales forecasts are also adjusted to reflect energy efficiency and distributed solar generation effects not represented in the historical database. The 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 take into account customer-owned solar generation in the residential, small commercial & industrial, and government customer classes. The estimates for energy efficiency energy savings and distributed generation energy impacts are accounted for in the annual retail sales energy forecasts in developing the expected Native System Energy value. In addition to the out-of-model adjustments, the contractual Rio Grande Electric Co-Operative ("RGEC") load is also incorporated into the forecast. The RGEC load is not considered a retail load for purposes of modeling the EPE system; it is a wholesale/native load customer.

EPE combines annual retail sales with sales to RGEC, company use, energy efficiency, and distributed generation and then calculates 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 Demand over time. 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 Demand is also adjusted for energy efficiency and distributed solar generation measures that impact system demand. The demand from both interruptible customers and wheeling losses-to-others are then accounted for to obtain the Total System Peak Demand. The 2015 Forecast can be found in ATTACHMENT B. A typical summer day hourly profile is shown below in FIGURE 4.

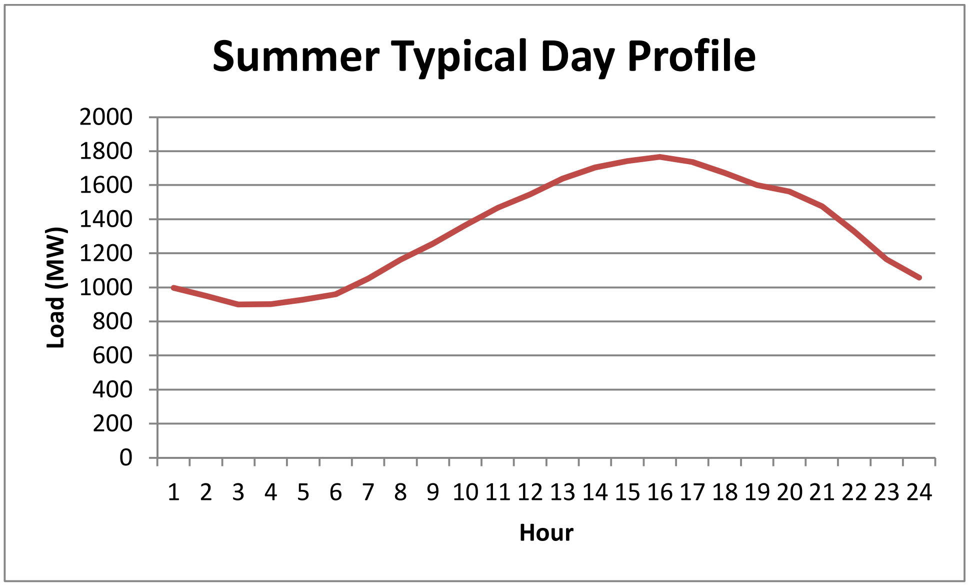


FIGURE 4. EPE Summer Typical Day Profile

X. RESERVE MARGIN CRITERION

EPE has no specific formal reserve margin criteria it is required to follow as a member of WECC. To determine a reasonable reserve margin criterion, EPE conducted a survey comparing the average Planning Reserve Margin for utility companies in the Southwest and WECC. Given EPE's geographic location and based on the results from the survey, EPE established its Planning Reserve Margin based on 15 percent of its total system demand. This criterion is consistent with reserve margin percentages for other utilities, which average 14.1 percent.

XI. SYSTEM LOADS AND RESOURCES ANALYSIS

A 10-year Load and Resources ("L&R") document, TABLE 13, illustrates EPE's current capacity resources, approved planned capacity additions, planned unit retirements and associated annual load forecast. EPE's long-term future resource needs are governed not only by load growth, but by the retirements of older existing generating units. The L&R document identifies planned new additions over the next ten years and is updated annually. The L&R document shows two LMS100 units being added in 2016 and 2017. These two units are Montana Power Station Units 3 and 4 which were part of the winning bid resulting from a RFP initiated in June 2011 to address a need for peaking capacity beginning in 2014. EPE received CCN approval in both Texas and New Mexico for the Montana Power Station. It also reflects the addition of the Rio Grande Unit 9 in 2013, the purchase of solar energy from Macho Springs beginning in 2014 and the addition of the Montana Units 1 and 2 in 2015. Based on this L&R, EPE needs new resources beginning in 2021 which this IRP will address.

TABLE 13. EPE's Load and Resources Document

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	275	275	275	275	275	229	229	229	229	229
1.2 NEWMAN	782	782	782	782	782	782	699	553	405	308
1.3 FOUR CORNERS	108	-	-	-	-	-	-	-	-	-
1.4 COPPER	64	64	64	64	64	64	64	64	64	64
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633
1.6 RENEWABLES	1	1	1	1	1	1	1	1	1	1
1.7 NEW BUILD (local)	264	352	352	352	352	352	352	352	352	352
1.0 TOTAL GENERATION RESOURCES (1)	**2,127**	**2,107**	**2,107**	**2,107**	**2,107**	**2,061**	**1,978**	**1,832**	**1,684**	**1,587**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27
2.2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7
2.5 RESOURCE PURCHASE	-	-	-	-		70	-	85	-	-
2.0 TOTAL RESOURCE PURCHASES (2)	**74**	**73**	**73**	**72**	**72**	**142**	**71**	**156**	**70**	**70**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,201**	**2,180**	**2,180**	**2,179**	**2,179**	**2,203**	**2,049**	**1,988**	**1,754**	**1,657**
4.0 SYSTEM DEMAND										
4.1 NATIVE SYSTEM DEMAND	**1,852**	**1,896**	**1,933**	**1,969**	**1,998**	**2,039**	**2,076**	**2,113**	**2,144**	**2,187**
4.2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)
4.3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)
4.4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4.5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.5)) (3)	**1,768**	**1,803**	**1,832**	**1,860**	**1,881**	**1,914**	**1,942**	**1,971**	**1,994**	**2,029**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**433**	**377**	**348**	**319**	**298**	**289**	**107**	**17**	**(240)**	**(372)**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	**265**	**270**	**275**	**279**	**282**	**287**	**291**	**296**	**299**	**304**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**168**	**107**	**73**	**40**	**16**	**2**	**(184)**	**(279)**	**(539)**	**(676)**

Generation Additions
LMS100 (88MW) in 2016
LMS100 (88 MW) in 2017

Unit Retirements
Four Corners 4 & 5 (108MW total) - July 2016
Rio Grande 7 (46MW) - December 2020
Newman 4 CC phased-out (ST - 83MW) - December 2021
Newman 4 CC phased-out (CT1 - 72MW) - December 2022
Newman 4 CC phased-out (CT2 - 72MW) - December 2023
Newman 1 (74MW) - December 2022
Newman 2 (76MW) - December 2023
Newman 3 (97MW) - December 2024
Copper (62MW) - December 2025
Rio Grande 8 (142MW) - December 2027

Purchases
SunEdison, NRG, Macho, Juwi and Hatch purchases reflect 70% availability at peak hour.

Resource Purchase reflects firm transmission available as a result of exchange agreement with McMoRan (Phelps Dodge) , from SPS and from PNM from Four Corners after Four Corners retires.

1. Generation unit retirements are per Burns & McDonnell study results.
2. Purchases based on existing and estimated future purchases including renewable purchases to meet RPS requirements.
   Resource Purchase reflects additional transmission capacity available through contract with McMoRan (Phelps Dodge), from SPS and from PNM from Four Corners after Four Corners retires.
3. System Demand based on Long-term and Budget Year Forecast issued April 1, 2015.
   Includes state-required energy efficiency targets for conservation, energy efficiency and load management.
   Interruptible load reflects current and contracts and includes new contract with Western Refinery. Excludes Ft. Bliss Net Zero initiatives.
4. Long-term resource needs will be evaluated based on system needs and are subject to change.

FUTURE RESOURCE OPTIONS

EPE identified several resource options for evaluation in its 20 year STRATEGIST model. EPE considered feasible supply-side and demand-side options described below. In evaluating future resource options, EPE considered capital costs, fixed and variable costs, maintenance costs, fuel costs, and heat rates. To obtain current pricing and operating parameters for various technologies, EPE used a combination of the Lazard Levelized Cost of Electricity ("LCOE") Analysis Version 8, data from proposals obtained from past Request for Proposals ("RFP") and quotes from manufactures. Lazard LCOE Analysis Version 8 is included in ATTACHMENT C. Also, EPE referenced Lazard as well as its own calculation to estimate the levelized cost of energy for each future resource option. The levelized cost of energy is not an input into EPE's planning software Strategist. The levelized cost of energy represents the per megawatt hour cost of operating and owning a generating project over its project life in real dollars. The levelized cost of energy is a good measure to show how competitive a resource option is against other options regardless of the type of technology.

EPE analyzed conventional supply-side technologies such as gas-fired combustion turbines, 2x1 and 1x1 combined-cycle units and renewable energy resources such as wind, solar, battery storage and biomass. Nuclear and Coal were not considered as options. Lastly, EPE considered demand-side alternatives such as direct load control ("DLC") programs.

A summary of the various technologies is provided below:

A. LANDFILL BIOMASS RESOURCE OPTION

Municipal solid waste from landfills generates methane gas when it undergoes bacterial decay. LFG seeps up through the landfill and goes into the atmosphere unless it is collected. LFG extraction systems have been operating for nearly 20 years. Landfill Gas differs from the interstate pipeline gas (about 100 percent methane) in that LFG contains 50 percent water and carbon dioxide as well as trace contaminants. These trace contaminants mostly include hydrogen sulfide and other toxic hydrocarbon species, along with some inorganic compounds. Compared to natural gas, LFG composition can negatively impact the performance of combustion technologies. The Btu content is also lower than natural gas and the water vapor content is usually much higher.

Electricity can be generated by burning LFG in internal combustion engines, small combustion turbines, boilers, and micro turbines. Approximately 63 percent (on a MW basis) of electric generating LFG facilities generate electricity with reciprocating engines. Other emergent technologies that can use LFG are Stirling engines, Organic Rankine cycle engines and fuel cells. FIGURE 5 shows a simple schematic of a LFG collection system and power plant.

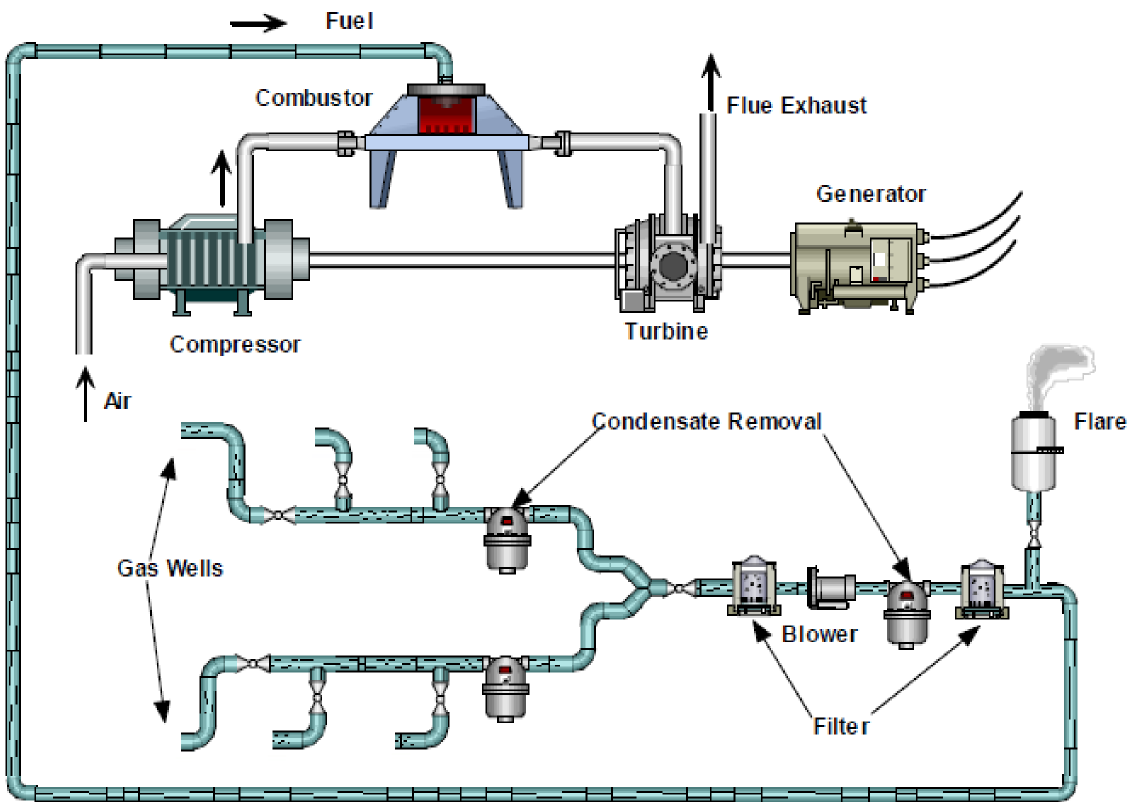


FIGURE 5. LFG Collection System and Power Plant

Currently in Dona Ana, the Camino Real Landfill is an LFG site that has been in operation for several years, with a current capacity of 1.5 MW and designed capacity of up to 3 MW. EPE purchases the output from this QF operation in accordance with FERC and NMPRC regulations. According to the Environmental Protection Agency ("EPA"), there are other potential LFG sites in the EPE service territory, which EPE plans to investigate if future projects appear feasible.

According to Lazard's Levelized Cost of Energy Analysis - Version 8.0, the construction time for a LFG power plant is three years and a plant life of 20 years. LFG plants are dispatchable and operate with capacity factors of 85 percent.

TABLE 14. Landfill Gas Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Heat Rate
	$/kW	$/MWh	$/kW-yr	$/MWh	Btu/kWh
2014	4,000	116.00	95	15	14,500

TABLE 15. Landfill Gas Emission Rates

NOx	CO	PM
(lbs/MWh)	(lbs/MWh)	(lbs/MWh)
1.42	0.20	0.06

TABLE 16. Landfill Gas Fuel Costs

Year	Fuel Costs
	$/MMBtu
2015	2.20
2016	2.20
2017	2.21
2018	2.22
2019	2.22
2020	2.23
2021	2.24
2022	2.24
2023	2.25
2024	2.26
2025	2.26
2026	2.27
2027	2.28
2028	2.28
2029	2.29
2030	2.30
2031	2.30
2032	2.31
2033	2.32
2034	2.33

B. SOLAR PHOTOVOLTAIC RESOURCE OPTION

A photovoltaic (“PV”) or solar cell is made of thin layers of silicon or other semiconductor materials so that when sunlight hits the cell the electrons flow through the material and produce electricity. Modules can be characterized as flat plates or concentrator systems. Approximately ten modules make up a flat plate PV array, which can be mounted at a fixed angle facing the sun or mounted on a tracking device for concentrator systems. For large utility applications hundreds of PV arrays are connected together. The electricity produced by a PV cell is direct current ("DC") and an inverter is used to convert the electricity to alternating current ("AC"). From the PV array to the bus bar electricity, losses are typically 20 percent of the initial amount produced, due to operational conditions. The efficiency of a solar cell is defined as the amount of absorbed light that is converted to electrical energy. Currently available commercial modules for wafer-based crystalline silicon technology are in the 20 to 30 percent range. Thin film technologies have slightly lower efficiencies but are less costly to manufacture. FIGURE 6 shows a simple diagram of how a solar cell produces electricity in a power plant. FIGURE 7 shows a simple schematic of a solar photovoltaic power plant.

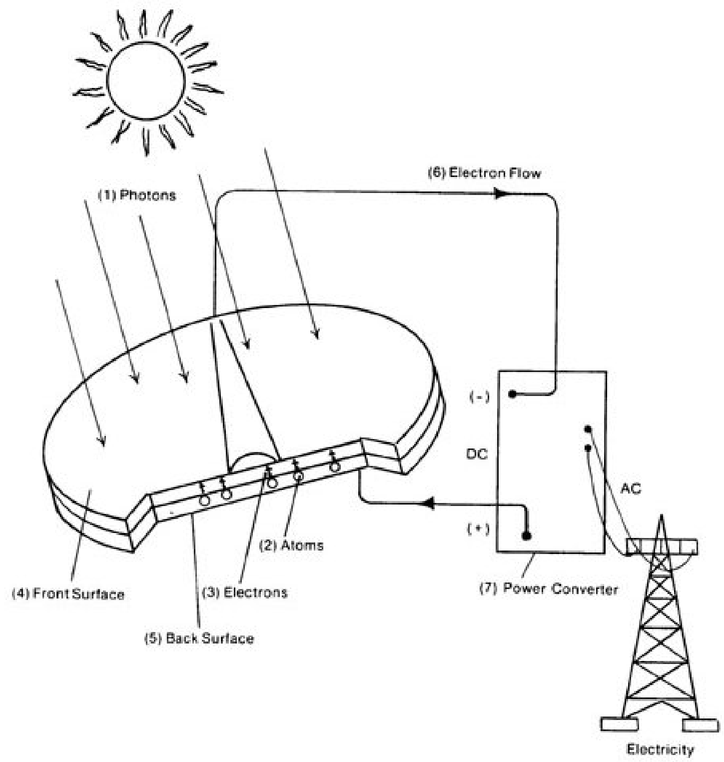


FIGURE 6. Solar Cell Power Plant Diagram

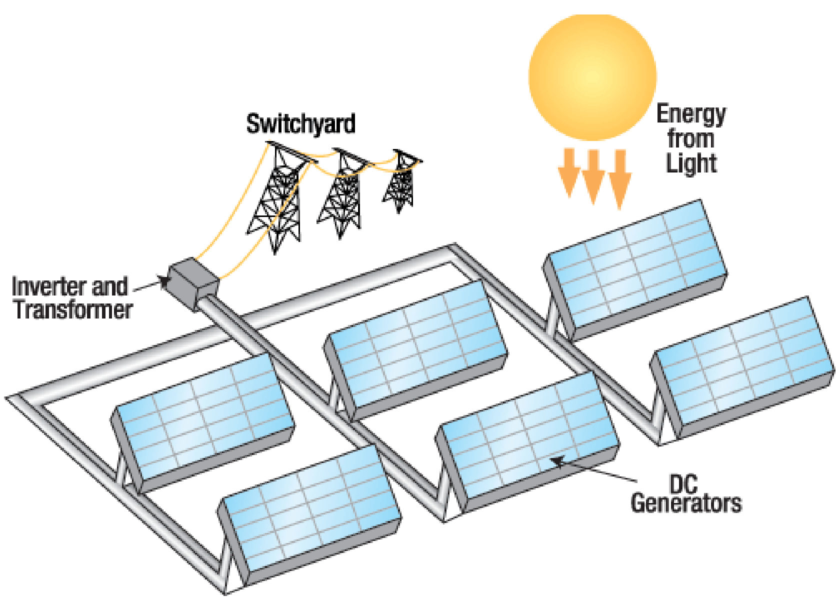


FIGURE 7. Solar Photovoltaic Power Plant Diagram

EPE currently offers Commission-approved, size-based programs to purchase RECs from customer-owned solar PV and wind generating QF systems. In 2009, EPE started the development of small solar pilot projects to gain experience with different technologies of panels including mono-crystalline, poly-crystalline, and Concentrated Photovoltaic (“CPV”). In the summer of 2009, EPE signed the first Purchase Power Agreement (“PPA”) for solar energy with NextEra (5 MWac). Since then, five facilities have been added to EPE’s portfolio: NRG (20 MWac), SunEdison 1 and 2 (22 MWac), Macho Springs (50 MWac) and PSEG (10 MWac) as described earlier in Section VI.

Moving forward, EPE’s goal is to build company-owned utility-scale facilities. EPE is working on the approval of four new projects as described earlier. These projects will total a capacity of 30 MWac.

EPE has evaluated commercial sized projects for modeling purposes. EPE evaluated a solar PV resource using all-in energy prices, taking into consideration annual energy production as well as project siting. According to Lazard's Levelized Cost of Energy Analysis - Version 8.0, the construction time for a solar PV thin-film power plant is one year, a plant life of 20 years and a capacity factor of 21 to 30 percent. Solar PV power plants are non-dispatchable and its pattern of generation is dependent upon external factors (weather conditions). Capacity factors vary depending on location. Initially EPE modeled Solar PV projects using the upper limit of Lazard’s of $1,750/kW in the base case. EPE received feedback from participant for EPE to use a lower capital cost ($/kW). Therefore, EPE used Lazard’s lower end capital cost estimate of $1,250. When EPE met with Commission Staff, it was suggested that EPE analyze a higher capital cost estimate for solar PV projects. EPE conducted a sensitivity in which Solar PV was modeled with a capital cost of $1,750/kW. This sensitivity is discussed in the results section.

TABLE 17. Solar Photovoltaic Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs
	$/kW	$/MWh	$/kW-yr	$/MWh
2014	1,750	72	20	-

C. NATURAL GAS COMBINED-CYCLE OPTION

Simple-cycle combustion turbine and combined cycle power plants are a mature generation technology representing about one-third of the electricity produced in the U.S. Combined Cycle units have become larger in capacity as the technology has advanced, due to capital cost economies-of-scale and improvements in efficiency.

The combined-cycle system was created to improve the efficiency of the combustion turbine. The combined-cycle consists of a combustion turbine, a heat recovery steam generator, and a steam turbine. One advantage of the conventional combined-cycle plant is that if repairs are needed on the steam turbine, they can be done without shutting down the entire system. Combustion turbines can still operate without the steam turbine, with decreased power output. Compared to other generation technologies, combined cycle units configured as either a 2x1 or 1x1 have lower total capital costs on a dollar per kilowatt ($/kW) bases, lower heat rate and a much higher efficiency. Combined cycle now have the ability to load follow and shut down all while maintaining emissions compliant. These capabilities are beneficial to EPE with the continued addition of renewable energy and when load drops in the evening to minimize excess energy.

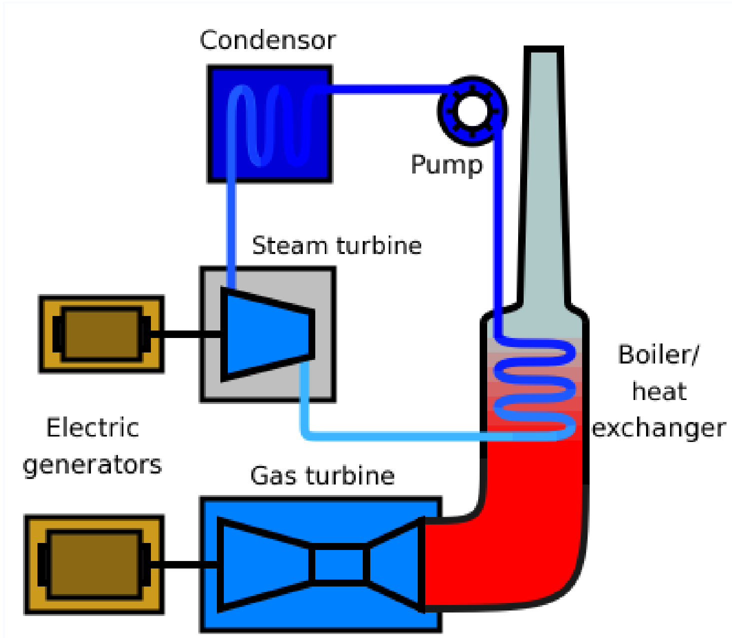


FIGURE 8. Working Principle of a Combined-Cycle Power Plant

According to Lazard's Levelized Cost of Energy Analysis Version 8.0, the construction time for a CTCC power plant is approximately three years and a plant life of 20 years. The capacity factor will depend on the specific utility's resource mix, load profile and dispatch parameters. FIGURE 8 shows a simple diagram showing how a combined-cycle plant functions. EPE's cost, price and unit characteristics' assumptions are contained in TABLES 18 to 20.

TABLE 18a. 2x1 Combined-Cycle Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Heat Rate
	$/kW	$/MWh	$/kW-yr	$/MWh	Btu/kWh
2014	1,072	97	6	1	8,000

TABLE 18b. 1x1 Combined-Cycle Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Heat Rate
	$/kW	$/MWh	$/kW-yr	$/MWh	Btu/kWh
2014	971	82	6	1	6,800

TABLE 19. Combined-Cycle Emission Rates

NO_X	CO_2
lbs/MWh	lbs/MWh
0.23	1,084.60

TABLE 20. Combined-Cycle Fuel - Natural Gas Costs

Year	Fuel Costs
	$/MMBtu
2015	3.17
2016	3.50
2017	3.84
2018	4.52
2019	4.62
2020	4.70
2021	4.79
2022	4.87
2023	4.97
2024	5.11
2025	5.37
2026	5.47
2027	5.61
2028	5.71
2029	5.84
2030	5.94
2031	6.20
2032	6.41
2033	6.60
2034	6.81

D. NATURAL GAS AERO-DERIVATIVE TURBINE

Conventional CTs have had wide-spread use since the 1940s. CTs use air as the working fluid. Air is drawn into the unit, compressed, and mixed with a fuel, usually natural gas or oil. The mixture is ignited and allowed to expand through a set of turbine blades. These blades are connected to a shaft which turns a generator, thus producing electricity. FIGURE 9 shows a diagram of the working principle of a combustion turbine unit.

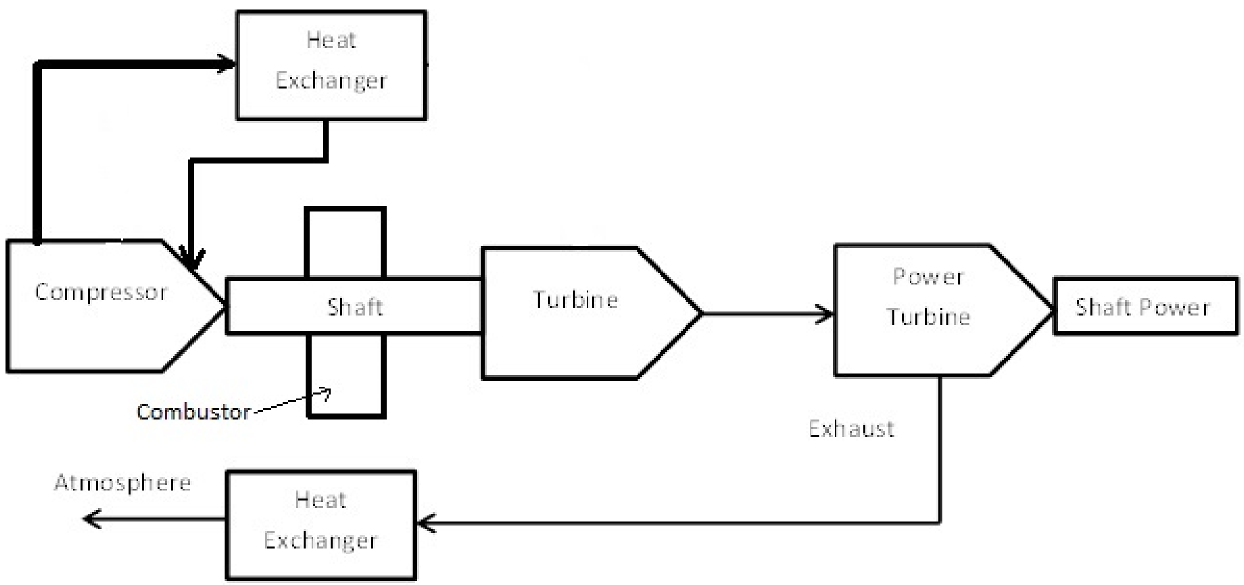


FIGURE 9. Working Principle of a Combustion Turbine Unit

EPE is analyzing combustion turbines with the intention of replacing existing generation and for peaking/intermediate and load following. The combustion turbine is a dispatchable unit that EPE will evaluate in order to replace other dispatchable retiring units. EPE modeled the LMS100 due to its high efficiency, ability ramp to up and down quickly, ability to cycle the unit, and its relatively low capital costs. According to Lazard's Levelized Cost of Energy Analysis - Version 8.0, the construction time for a conventional combustion turbine power plant is approximately two years, a plant life of 20 years. The capacity factor will depend on the specific utility's resource mix, load profile and dispatch parameters. EPE modeled the LMS100 due to its high efficiency and relatively low capital costs. EPE's cost, price and unit characteristics' assumptions are shown in TABLES 21 to 23.

TABLE 21. LMS100 Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Heat Rate
	$/kW	$/MWh	$/kW-yr	$/MWh	Btu/kWh
2014	1,065	111	4	3	9,500

TABLE 22. LMS100 Emission Rates

NOx	CO_2	CO
lbs/MWh	lbs/MWh	lbs/MWh
0.10	1,050.13	0.04

TABLE 23. LMS100 Fuel – Natural Gas Costs

Year	Fuel Costs
	$/MMBtu
2015	3.17
2016	3.50
2017	3.84
2018	4.52
2019	4.62
2020	4.70
2021	4.79
2022	4.87
2023	4.97
2024	5.11
2025	5.37
2026	5.47
2027	5.61
2028	5.71
2029	5.84
2030	5.94

2031	6.20
2032	6.41
2033	6.60
2034	6.81

E. BATTERY STORAGE

Battery storage is used to store electricity on a large scale within an electrical power grid. Battery storage has no water or air emissions and does not require any water. Battery storage also does not require a fuel source such as natural gas and therefore the energy cost per MWh can be tied to lower marginal costs generation such as nuclear, coal or even negative price wind generation. Current battery technology allows for operational flexibility such as dispatching to follow increase or decrease in load while remaining fully synchronized with the grid. Battery storage is also a resource for regulation service, improving ACE/frequency/system quality. FIGURE 10 shows a diagram of how a generic battery storage system operates. According to Lazard's Levelized Cost of Energy Analysis - Version 8.0, the construction time for a battery storage unit is 3 months, a plant life of 20 years and a capacity factor of 25 percent. The units factors used in Strategist for a battery storage unit is shown below in TABLE 24.

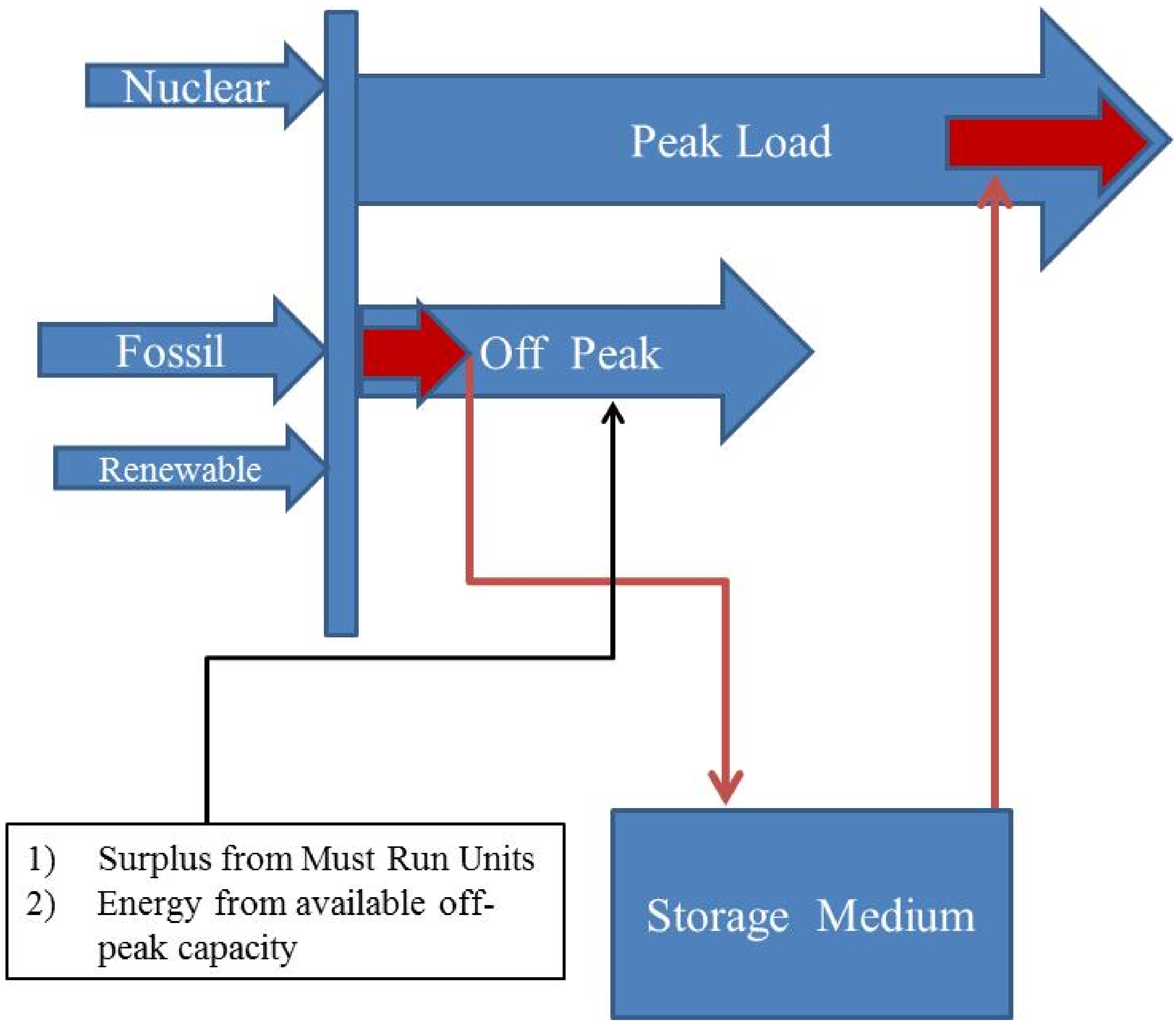


FIGURE 10. Battery Storage Diagram

TABLE 24. Battery Storage Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs
	$/kW	$/MWh	$/kW-yr	$/MWh
2014	750	324	22	-

F. LOAD MANAGEMENT RESOURCE OPTION

Load management is an effective operating tool under two different system operating conditions. One is when power demand slowly increases and the load has to be brought up to a preset threshold. Another situation is when load has to be brought down from some high value to a preset threshold as quickly as possible. The common approach is to disconnect customers in the order assigned by the company and keep them disconnected as long as needed. When disconnect times are long the company may opt for load rotation, that is reconnecting disconnected customers after some elapsed time while disconnecting others. The principle of load management systems is to automate these procedures and to run them as quickly and efficiently as allowed by local circumstances. Load management resource technology has three components: a network operations center, which is a centralized communication infrastructure from which the load control system conducts its remote monitoring, dispatch, data collection, and reporting; a site server, which is an advanced metering and communications node located at each end-user site; and a web-based energy information system.

EPE's modeling assumptions were derived from proposals EPE received from previous RFPs and is shown in TABLE 25. Data from these proposals were averaged to preclude any data from a specific proposal from being shared.

TABLE 25. Load Management Unit Factors

Year	Capital Costs	Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs	Demand Response per Customer
	$/kW	$/MWh	$/kW-yr	$/MWh	kW
2014	320	443	-	-	250

G. WIND RESOURCE OPTION

Wind energy has become an important source of renewable energy. Currently, the most common configuration for wind turbines is a three-blade, upwind, horizontal-axis design. Figure 11 gives a front and side view of a typical wind turbine. Wind turbines function within a wind speed window, which is defined by the "cut-in" and "cut-out" wind speeds. Power output increases with wind speed up to the speed for which it is rated. The turbine produces its rated output at speeds between the rated wind speed and the cut-out speed. The nameplate capacity of a wind turbine can be approximated by the size of the generators being used.

Wind turbine power plants are non-dispatchable and its pattern of generation is dependent upon external factors. Lazard's Levelized Cost of Energy states wind turbines operate with capacity factor of 30 to 52 percent. Capacity factors can vary drastically depending on location. Operating wind farms have capacity factors ranging from 24 percent to 36 percent, a lead time of 12 months and a plant life of 20 years. EPE's modeling assumptions were derived from Lazard's Levelized Cost of Energy Analysis and from proposal's EPE received from previous RFPs and is shown in TABLE 26. Data from these proposals were averaged to preclude any data from a specific proposal from being shared. Also, due to the vary output from wind energy EPE tacked on wind regulation costs shown in TABLE 27.

TABLE 26. Wind Unit Factors

Year	Capital Costs	**Levelized Cost of Energy	Fixed Operating and Maintenance Costs	Variable Operating and Maintenance Costs
	$/kW	$/MWh	$/kW-yr	$/MWh
2014	1,400	81	22	-

TABLE 27. Wind Regulation Costs

Year	Annual Cost
	$
2015	1,212,665
2016	1,248,944
2017	1,333,403
2018	1,507,610
2019	1,552,585
2020	1,580,091
2021	1,609,238
2022	1,638,902
2023	1,669,973
2024	1,749,795
2025	1,969,045
2026	2,007,525
2027	2,084,142
2028	2,122,872
2029	2,189,243
2030	2,215,475
2031	2,433,722
2032	2,582,026
2033	2,716,874
2034	2,863,877

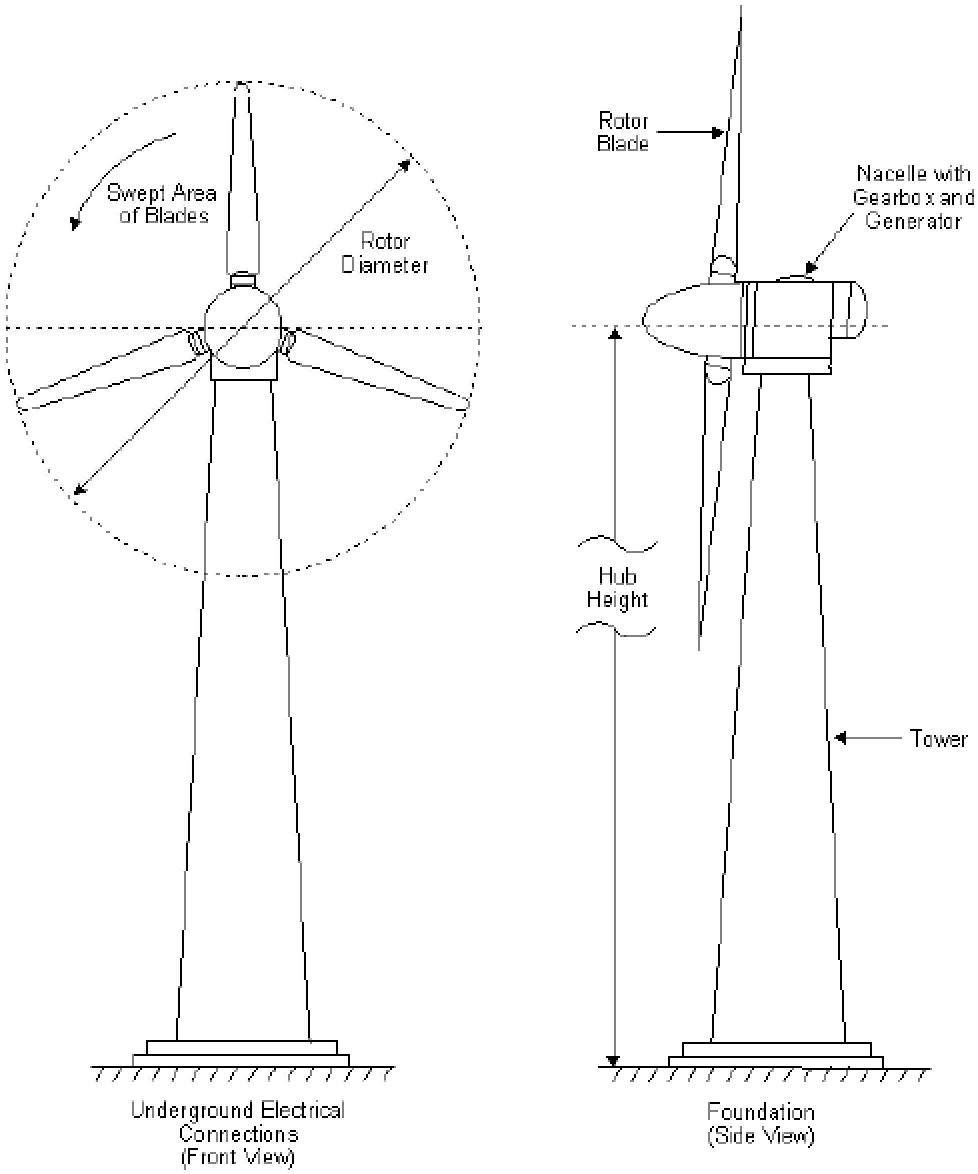


FIGURE 11. Wind Turbine Front and Side View

XII. EPE'S MOST COST EFFECTIVE PORTFOLIO AND ALTERNATIVES

EPE utilizes an optimization program, STRATEGIST, to model resource options. STRATEGIST incorporates aspects of utility planning and operations including forecasted load modeling, marketing and conservation programs, production cost calculations, dispatch of energy resources, optimization of future decisions, and non-production related cost recovery (e.g., construction expenditures, AFUDC, and property taxes) via a number of internal modules. To identify the most cost-effective resource portfolio, EPE evaluated the identified, feasible supply and demand-side resource options on a consistent and comparable basis. EPE has taken into consideration identifiable risks and uncertainties (including but not limited to financial, competitive, reliability, operational, fuel supply, price volatility and anticipated environmental regulation). EPE has also evaluated the cost of each resource through its projected life with a life-cycle or similar analysis.

EPE considered a variety of resource options in order to develop the most cost-effective or "least cost" expansion plan while considering both customer input and regulatory mandates. EPE analyzed a number of alternatives for economic and operational feasibility. In addition, EPE accounted for transmission and reserve margin constraints in the analyses to capture the effects of these parameters on EPE's system reliability. As such, EPE's long-term expansion planning process includes supply-side generation technologies, including renewable resources, and demand-side alternatives to meet EPE's future growth. Supply-side and demand-side alternatives were analyzed on a cost-effective and reliability basis. Determining the best expansion plan and combination of alternatives required analyses incorporating technology, economics and system compatibility. While the analysis of every option is not possible, EPE evaluated major supply-side and demand-side alternatives based on individual technology, economics, and fuel parameters to determine which technologies met EPE's native system needs.

A. IRP STUDY PROCESS

The IRP Study process began with a high level screening of several technologies. Each technology's advantages and disadvantages were considered using certain criteria to determine which alternatives to evaluate further in STRATEGIST. EPE conducted a preliminary screening and economic assessment, aided primarily by Lazard's Levelized Cost of Energy Analysis Version 8.0 and other sources. The factors considered included capital costs, fuel and O&M costs, construction times, reliability, heat rates, environmental impact, present and impact on EPE’s reserve margin.

EPE relied on Lazard's Levelized Cost of Energy Analysis Version 8.0 for cost and operating parameters for various technologies. In general, Lazard's Levelized Cost of Energy Analysis enables EPE to evaluate and compare the competitive price of electricity for various power generation (fossil, renewable, small-scale generation, and nuclear) to identify costs (such as capital, fixed and variable O&M, and environmental/emission) associated with these alternatives which were then used in whole or part and/or in combination with data from other sources in STRATEGIST for modeling purposes. The technologies EPE considered were biomass, natural gas CTs (aeroderivatives – LMS100), natural gas CCs (framed machines – 2x1 and 1x1), solar PV (thin-film), wind, DSM and battery storage.

B. DEVELOPMENT OF SCENARIOS FOR STRATEGIST EVALUATION

1. Base Case

A base case was developed in which EPE’s system was updated with all current data such as load forecast, fuel prices and unit operating parameters. The alternative generation units were also modeled in the base case. Strategist simulates thousands of resource expansion plans that are ranked based on each plan's total Present Value ("P.V.") Utility Cost. TABLE 28 shows the base case expansion plan results. Results from EPE's Base Case Resource Plan consist of 13 unit additions to be built over the next twenty years. The entire STRATEGIST results for this plan can be found in ATTACHMENT D.

TABLE 28. Base Case Expansion Plan Results

	Base Case	
	Unit	**Installed Capacity (MW)**
2022	1x1 CC	281
2023		
2024	1x1 CC	281
	10 PV	10
2025	20 PV	20
	LMS100	88
2026	LMS100	88
	10 PV	10
2027	20 PV	20
	WIND	22
2028	1x1 CC	281
2029		
2030		
2031	10 PV	10
2032	LMS100	88
2033		
2034	LMS100	88
	Present Value Utility Cost (k$)	**Total Installed Capacity (MW)**
	4,463,904	**1,287**

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

**Wind resource is 100 MW gross (22MW at peak)

C. SENSITIVITY ANALYSIS OF SCENARIOS

EPE analyzed various sensitivities to capture the cost impact and impact to the resultant expansion plan if it varied its projected load, forecasted natural gas prices and included carbon tax at different price thresholds. Therefore, EPE modeled and analyzed high and low sensitivities on load, natural gas prices and carbon tax. Results from the STRATEGIST sensitivities are presented in ATTACHMENT D, which include the present value utility costs for each plan.

1. Higher Solar Capital Cost Sensitivity

Based on feedback from EPE's meeting with NMPRC staff, EPE ran a sensitivity in which the capital cost for solar projects was increased. Previously, EPE selected a capital cost of $1,250/kW based on the lower range from Lazard's Levelized Cost of Energy Analysis. In this sensitivity, the capital cost for the solar projects were modified to reflect the capital cost on the higher end of Lazard's Levelized Cost of Energy Analysis of $1,750/kW. TABLE 29 below shows the results of this sensitivity. The results of the sensitivity show no change in the units selected for the expansion plan when compared to the base case.

TABLE 29. Solar-Higher Capital Cost Sensitivity Expansion Plan Results

	Higher Solar Cost Case	
	Unit	Installed Capacity (MW)
2022	1x1 CC	281
2023		
2024	1x1 CC	281
	10 PV	10
2025	20 PV	20
	LMS100	88
2026	LMS100	88
	10 PV	10
2027	20 PV	20
	WIND	22
2028	1x1 CC	281
2029		
2030		
2031	10 PV	10
2032	LMS100	88
2033		
2034	LMS100	88
	Present Value Utility Cost (k$)	**Total Installed Capacity (MW)**
	4,474,195	**1,287**

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

**Wind resource is 100 MW gross (22MW at peak)

2. Load Sensitivities

For EPE's high and low load sensitivities, EPE analyzed its 2015 Energy and Demand Forecast to reflect economic recovery and a more robust economy (increases in customers and businesses) by an increase of 15 percent. EPE then analyzed a lower bound of its Load Forecast to represent a decline of the economy (e.g., closure of businesses, loss of customers and military troops projected to be transferred to the El Paso area) by decreasing its load by 15 percent. TABLE 30 shows the load sensitivity results. The results of the sensitivity changed compared to the Base Case Resource

Plan. In the 15 percent decrease case, less generation was needed upfront therefore the first generation addition was pushed back until 2024. In the 15 percent increase case, additional generation was needed upfront so a 20MW solar PV unit was added in 2023.

The results of these sensitivities changed the expansion plan when compared to the base case. In the -15% Load sensitivity the amount of capacity need to meet EPE's load was reduced in conjunction with the decrease in load. The sensitivity shows EPE's first generation addition should be in 2024. In the +15% Load sensitivity shows EPE's should include more natural gas generation instead of renewable energy projects.

TABLE 30. High Load versus Low Load Sensitivities

	-15% Load		+15% Load	
	Unit	Installed Capacity (MW)	Unit	Installed Capacity (MW)
2022			1x1 CC	281
2023			20 PV	20
2024	20 PV	20	1x1 CC	281
	1x1 CC	281		
2025	20 PV	20	LMS100 (2)	176
2026	LMS100	88	LMS100	88
	10 PV	10		
2027	WIND	22		
	10 PV	10		
2028	1x1 CC	281	1x1 CC	281
2029				
2030			10 PV	10
2031			20 PV	20
2032	10 PV	10	20 PV	20
2033	LMS100	88	LMS100	88
2034				
	Present Value Utility Cost (k$)	**Total Installed Capacity (MW)**	**Present Value Utility Cost (k$)**	**Total Installed Capacity (MW)**
	4,240,565	**830**	**4,486,028**	**1,265**

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

**Wind resource is 100 MW gross (22MW at peak)

3. Natural Gas Price Sensitivities

On the high and low natural gas price sensitivities, EPE analyzed a 15 percent price increase and a 15 percent decrease, respectively. Since the heat rate of the 1x1 CC is low, the effect of an increase in fuel prices is minimal. The results of the fuel sensitivity did not alter from the Base Case Resource Plan are shown below in TABLE 31. The results of the sensitivity show no change in the units selected for the expansion plan when compared to the base case.

TABLE 31. High Natural Gas versus Low Natural Gas Sensitivities

	-15% Fuel		+15% Fuel	
	Unit	Installed Capacity (MW)	Unit	Installed Capacity (MW)
2022	1x1 CC	281	1x1 CC	281
2023				
2024	1x1 CC	281	1x1 CC	281
	10 PV	10	10 PV	10
2025	20 PV	20	20 PV	20
	LMS100	88	LMS100	88
2026	LMS100	88	LMS100	88
	10 PV	10	10 PV	10
2027	20 PV	20	20 PV	20
	WIND	22	WIND	22
2028	1x1 CC	281	1x1 CC	281
2029				
2030				
2031	10 PV	10	10 PV	10
2032	LMS100	88	LMS100	88
2033				
2034	LMS100	88	LMS100	88
	Present Value Utility Cost (k$)	**Total Installed Capacity (MW)**	**Present Value Utility Cost (k$)**	**Total Installed Capacity (MW)**
	4,145,093	**1,287**	**4,499,168**	**1,287**

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

**Wind resource is 100 MW gross (22MW at peak)

4. Carbon Tax Sensitivities

EPE used the carbon tax price thresholds of \$8 and \$20 as reasonable representations of potential pricing. EPE used the \$0 carbon tax price as part of its Base Case, with the \$8 and \$20 sensitivities representing the lower and upper bounds of the carbon tax. Since EPE's resource plan doesn't consist of any coal units, the effect of a carbon tax is minimized. As shown in TABLE 32 below, there were no major changes to the resource plan.

TABLE 32. Carbon Tax Price Sensitivities

	\$8 CO2		\$20 CO2	
	Unit	Installed Capacity (MW)	Unit	Installed Capacity (MW)
2022	1x1 CC	281	1x1 CC	281
2023				
2024	1x1 CC	281	1x1 CC	281
	10 PV	10	10 PV	10
2025	20 PV	20	20 PV	20
	LMS100	88	LMS100	88
2026	LMS100	88	LMS100	88
	10 PV	10	10 PV	10
2027	20 PV	20	20 PV	20
	WIND	22	WIND	22
2028	1x1 CC	281	1x1 CC	281
2029				
2030				
2031	10 PV	10	10 PV	10
2032	LMS100	88	LMS100	88
2033				
2034	LMS100	88	LMS100	88
	Present Value Utility Cost (k\$)	**Total Installed Capacity (MW)**	**Present Value Utility Cost (k\$)**	**Total Installed Capacity (MW)**
	4,640,444	**1,287**	**4,906,233**	**1,287**

1x1 CC – One by One Combined Cycle
2x1 CC – Two by One Combined Cycle
LMS100 – Gas Turbine
10PV – Solar Photovoltaic (10 MW)
20PV – Solar Photovoltaic (20 MW)
Wind – Wind (22 MW)

**Wind resource is 100 MW gross (22MW at peak)

XIII. EPE'S RECOMMENDED RESOURCE PLAN

Although the IRP process, along with the aid of EPE's STRATEGIST optimization model, help EPE identify cost effective resources that could serve EPE's customers over the next 20 years, EPE conducted a final review/assessment on the resulting resource plans to make sure it is reasonable and that it incorporates/captures all potential options available to EPE to meet its customers' needs. As a result, EPE recommends its Base Case resource plan. Please refer to ATTACHMENT G for EPE's Official 20-Year L&R Document which incorporates this resource plan.

XIV. FOUR-YEAR ACTION PLAN

The IRP Rule requires that EPE detail the specific actions it will take to implement the IRP spanning the four-year period for 2013 through 2016. The actions EPE has taken with respect to its 2009 IRP's four-year plan are addressed above in Section II of this document. In the previous section, EPE has identified its most cost effective resource plan based on current economic assumptions and load and energy forecasts. EPE will continue to monitor these factors and adjust its resource additions in the future as needed.

EPE's IRP generally identifies the recommended resource additions by resource type. As part of EPE's 2015 IRP's Four-Year Action Plan, EPE intends to identify the most economical resource needed during the time period, through competitive-bid RFP processes. Over the next four years, EPE will do the following:

1. EPE will complete the regulatory process to terminate its participation and sell its ownership interest in the Four Corners Power Plan in July 2016.

2. EPE will complete the regulatory process for approval of its 2015 Annual Renewable Energy Plan Application filed with the Commission (15-00117-UT); and will file annual renewable energy plan application on May 1 in 2016, 2017, 2018 and 2019 pursuant to Rule 17.9.572 NMAC and the REA.
3. EPE will file annual applications for Commission approval of proposed energy efficiency measures or programs and load management measures or programs on July 1, beginning 2016 pursuant to Rule 17.7.2 NMAC and the EUEA.
4. EPE will issue a RFP process for a pilot demand response program to evaluate a demand-side management program.
5. EPE will issue an All-Source RFPs in 2016 or 2017 to address the resource need identified in 2022. The exact date for the RFP will be determined based on a continued evaluation of future changes to forecasted loads, economic conditions, technological advances, and environmental and regulatory standards as mentioned before.

XV. CONCLUSION

EPE's IRP complies with the procedures and objectives set forth in the IRP Rule. EPE's IRP is designed to meet EPE's future capacity needs as well as comply with its energy efficiency and renewable energy requirements and anticipated environmental laws and regulations. EPE obtained valuable input through the public advisory process, and the IRP identifies the most cost effective portfolio of resources to supply the energy needs of EPE's customers.

EPE's L&R also shows that EPE would be capacity deficient starting in year 2021. The Base Case resource plan shown in TABLE 28 represents EPE's most cost effective resource plan. It provides a mix of peak, intermediate/base load generation. It also provides a resource portfolio with fuel and technology diversity. The sensitivities show that while the timing may be different, similar resources are added indicating the recommended resource plan is robust and can be modified over time as needed, based on changes in load, higher levels of energy efficiency measures, changes in fuel costs, changes in carbon tax levels, and changes in other economic and environmental factors.

ATTACHMENT A – Existing Units Operating Characteristics

TABLE A-01a

Unit Copper	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	0.12	35.52	16.00	336.69
2016	0.05	14.10	14.11	336.27
2017	0.09	27.85	13.65	348.52
2018	0.07	26.56	13.70	355.36
2019	0.01	4.81	15.37	355.40
2020	0.02	9.16	15.27	364.66
2021	0.07	29.97	14.97	378.88
2022	0.01	5.93	14.10	383.65
2023	0.05	20.41	14.90	397.54
2024	0.12	54.91	15.12	418.63
2025	0.03	14.16	14.87	414.72

TABLE A-01b

Unit Four Corners 4	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	80.44	7,622.35	10.02	5,063.98
2016	40.51	4,401.49	10.02	3,771.36

Unit Four Corners 5	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	60.69	5,738.02	10.02	7,734.93
2016	43.88	4,770.27	10.02	3,285.79

TABLE A-01c

Unit Newman 1	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	0.32	78.76	11.57	1,329.11
2016	0.07	20.60	11.28	1,420.46
2017	0.06	18.80	11.08	1,339.22
2018	0.08	29.42	11.05	1,445.48
2019	0.03	10.79	11.43	1,473.28
2020	0.05	19.41	11.39	1,507.06
2021	0.15	55.79	11.31	1,542.92
2022	0.02	8.45	11.23	1,588.62

Unit Newman 2	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	0.87	204.40	10.85	1,309.31
2016	0.17	45.51	10.88	1,390.91
2017	0.13	37.49	10.73	1,310.99
2018	0.13	45.04	10.76	1,414.63
2019	0.09	31.88	10.85	1,442.02
2020	0.10	37.78	10.83	1,474.97
2021	0.33	122.38	10.81	1,512.70
2022	0.05	18.32	10.81	1,554.25
2023	0.11	43.85	10.82	1,595.18

Unit Newman 3	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	27.31	8,381.27	11.06	2,055.21
2016	20.53	7,298.42	11.18	2,082.78
2017	25.68	9,912.67	11.12	2,066.39
2018	17.30	8,098.13	11.33	2,077.72
2019	24.47	11,456.90	11.20	2,234.73
2020	24.67	11,775.52	11.19	2,289.16
2021	20.96	10,128.04	11.15	2,277.03
2022	23.40	11,615.15	11.27	2,389.67
2023	25.06	12,567.25	11.16	2,479.58
2024	25.70	13,117.61	11.12	2,563.01

Unit Newman 4	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	45.65	31,136.94	10.53	3,850.88
2016	41.62	32,260.84	10.42	6,727.38
2017	57.57	45,597.68	9.79	4,607.84
2018	57.88	54,773.93	9.86	4,399.89
2019	41.04	42,374.30	10.55	9,782.41
2020	45.68	47,290.63	10.38	6,450.49
2021	54.59	55,529.23	10.03	4,629.15
2022	34.22	29,421.27	13.22	7,589.21
2023	33.62	24,281.36	21.65	4,543.16

Unit Newman 5	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	29.28	20,966.95	8.33	6,490.91
2016	37.91	29,740.48	8.26	4,874.44
2017	39.76	34,254.47	8.26	6,871.59
2018	39.17	39,720.07	8.27	11,634.52
2019	60.87	62,686.88	8.27	4,741.65
2020	61.78	64,907.20	8.26	6,239.10
2021	52.22	55,720.49	8.26	7,519.42
2022	54.33	59,528.63	8.34	4,888.03

2023	51.81	58,365.39	8.40	5,739.06
2024	41.96	48,773.01	8.40	11,269.49
2025	48.10	58,715.90	8.43	5,692.05
2026	44.77	55,680.72	8.42	5,652.64
2027	44.99	57,142.73	8.40	5,730.37
2028	47.01	61,275.41	8.43	5,879.48
2029	46.43	61,849.79	8.43	5,932.84
2030	42.66	57,727.13	8.43	5,870.57
2031	46.90	66,237.21	8.44	6,100.24
2032	47.01	68,757.06	8.44	6,187.64
2033	49.09	73,668.21	8.43	6,343.03
2034	47.63	73,795.26	8.43	6,368.03

TABLE A-01d

Unit Rio Grande 7	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	1.17	162.98	10.57	1,765.47
2016	0.60	91.45	10.48	1,799.78
2017	0.31	51.56	10.44	1,837.54
2018	0.36	70.61	10.43	1,884.86
2019	0.35	71.16	10.43	1,922.26
2020	0.42	86.51	10.43	1,966.59

Unit Rio Grande 8	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	19.30	8,820.92	11.14	3,913.78
2016	19.50	9,765.88	11.12	4,009.67
2017	15.87	8,660.35	11.02	3,982.46
2018	25.96	16,736.11	11.02	4,413.47
\2019	33.55	22,161.50	11.10	4,752.86
2020	28.43	19,116.55	11.04	4,691.17
2021	34.66	23,599.82	11.02	5,342.49
2022	32.50	22,832.46	11.19	5,427.28
2023	27.11	19,495.04	11.15	5,376.08
2024	33.05	24,325.45	11.15	5,753.01
2025	23.82	18,781.54	11.31	5,514.23
2026	31.08	24,810.93	11.31	5,904.32
2027	32.92	26,553.22	11.15	6,096.46

Unit Rio Grande 9	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	8.27	1,924.89	9.34	1,807.25
2016	12.76	3,316.96	9.49	1,962.05
2017	14.53	4,092.11	9.38	2,050.49
2018	19.17	6,572.67	9.67	2,223.90
2019	10.26	3,495.69	9.32	2,032.75
2020	11.11	3,856.70	9.32	2,102.47

2021	13.74	4,840.83	9.28	2,558.33
2022	6.14	2,215.39	9.37	2,414.52
2023	6.03	2,209.52	9.30	2,473.83
2024	7.17	2,722.55	9.32	2,580.23
2025	3.29	1,306.04	9.31	2,508.63
2026	3.86	1,560.46	9.31	2,577.05
2027	8.34	3,459.35	9.32	2,775.26
2028	1.65	699.90	9.37	2,607.26
2029	2.36	1,021.15	9.34	2,683.60
2030	4.49	1,985.08	9.36	2,811.68
2031	2.18	1,000.63	9.30	2,785.94
2032	2.37	1,122.55	9.29	2,848.51
2033	4.20	2,051.65	9.32	2,972.77
2034	3.07	1,538.26	9.28	2,989.65

TABLE A-01e

Unit Palo Verde 1	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	92.37	16,612.48	10.21	29,878.38
2016	85.70	14,341.17	10.21	29,858.04
2017	87.59	14,803.77	10.21	31,065.67
2018	95.47	17,544.92	10.21	31,150.26
2019	84.57	16,057.24	10.21	31,065.15
2020	86.37	16,959.28	10.21	31,217.41
2021	95.73	18,275.44	10.21	31,302.40
2022	87.10	17,170.23	10.21	31,628.15
2023	88.52	18,039.29	10.21	31,541.74
2024	96.58	20,171.92	10.21	31,696.08
2025	89.35	18,980.32	10.21	31,782.64
2026	89.86	19,406.69	10.21	32,113.36
2027	90.92	20,060.75	10.21	32,025.62
2028	88.61	19,983.29	10.21	32,182.05
2029	90.45	20,660.10	10.21	32,358.58
2030	91.66	21,374.70	10.21	32,516.29
2031	89.07	21,166.88	10.21	32,516.29
2032	90.74	21,980.62	10.21	32,675.32
2033	92.11	22,717.21	10.21	32,764.84
2034	89.26	22,431.28	10.21	33,015.29

Unit Palo Verde 2	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	90.46	16,226.88	10.19	29,878.38
2016	98.52	16,441.85	10.19	29,858.04
2017	90.45	15,283.66	10.19	31,065.67
2018	90.61	16,599.43	10.19	31,150.26
2019	98.60	18,668.08	10.19	31,065.15
2020	90.41	17,750.02	10.19	31,217.41
2021	90.59	17,237.38	10.19	31,302.40
2022	98.60	19,390.20	10.19	31,628.15

2023	90.45	18,427.41	10.19	31,541.74
2024	90.62	18,868.95	10.19	31,696.08
2025	98.60	20,884.91	10.19	31,782.64
2026	89.59	19,359.53	10.19	32,113.36
2027	91.16	20,026.35	10.19	32,025.62
2028	98.60	22,158.58	10.19	32,182.05
2029	89.59	20,472.05	10.19	32,358.58
2030	91.16	21,164.73	10.19	32,516.29
2031	98.60	23,356.48	10.19	32,516.29
2032	89.59	21,711.61	10.19	32,675.32
2033	91.16	22,383.21	10.19	32,764.84
2034	98.60	24,698.74	10.19	33,015.29

Unit Palo Verde 3	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	89.65	16,135.88	10.21	29,878.38
2016	89.51	14,948.44	10.21	29,858.04
2017	98.39	16,643.06	10.21	31,065.67
2018	90.26	16,592.35	10.21	31,150.26
2019	90.34	17,105.71	10.21	31,065.15
2020	98.41	19,326.69	10.21	31,217.41
2021	90.42	17,255.20	10.21	31,302.40
2022	90.45	17,795.90	10.21	31,628.15
2023	98.56	20,100.34	10.21	31,541.74
2024	90.40	18,892.26	10.21	31,696.08
2025	90.54	19,191.76	10.21	31,782.64
2026	98.59	21,314.27	10.21	32,113.36
2027	89.53	19,746.24	10.21	32,025.62
2028	84.74	19,076.84	10.21	32,182.05
2029	98.60	22,542.25	10.21	32,358.58
2030	89.59	20,883.53	10.21	32,516.29
2031	84.86	20,127.40	10.21	32,516.29
2032	98.60	23,900.68	10.21	32,675.32
2033	89.59	22,085.82	10.21	32,764.84
2034	85.29	21,389.69	10.21	33,015.29

TABLE A-01f

Unit Montana 1	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	2.62	632.89	9.82	283.84
2016	6.09	1,616.30	9.84	479.90
2017	7.02	2,038.06	9.81	506.94
2018	10.54	3,580.12	9.90	599.57
2019	4.75	1,653.73	9.73	453.85
2020	5.16	1,827.48	9.73	467.68
2021	8.13	2,941.51	9.73	554.69
2022	2.34	867.09	9.79	392.51
2023	3.53	1,323.90	9.72	428.78
2024	3.87	1,506.49	9.77	441.77

2025	1.80	733.10	9.76	380.16
2026	2.16	890.73	9.75	392.16
2027	4.49	1,905.05	9.77	467.61
2028	0.20	85.47	9.80	331.41
2029	1.24	547.49	9.77	365.96
2030	0.50	225.66	9.80	341.90
2031	1.23	577.66	9.75	367.41
2032	1.36	659.80	9.74	372.88
2033	2.25	1,125.22	9.77	405.62
2034	1.84	944.28	9.72	392.25

Unit Montana 2	**Capacity Factor**	**Fuel Costs**	**Heat Rate**	**Fixed and Variable O&M**
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2015	1.21	292.27	9.82	248.52
2016	2.65	709.97	9.88	392.76
2017	3.12	915.90	9.86	406.38
2018	4.85	1,661.33	9.86	452.89
2019	2.73	950.26	9.73	399.04
2020	2.99	1,060.89	9.72	407.86
2021	4.67	1,687.26	9.73	456.85
2022	1.16	429.25	9.79	358.44
2023	2.03	762.42	9.74	384.70
2024	2.02	787.68	9.77	386.01
2025	0.93	381.24	9.78	353.64
2026	1.16	479.48	9.77	361.11
2027	2.28	972.45	9.79	397.70
2028	0.10	41.94	9.78	328.16
2029	0.65	288.65	9.77	346.60
2030	0.25	111.56	9.79	333.37
2031	0.65	307.94	9.77	347.58
2032	0.74	358.77	9.76	351.00
2033	1.18	587.94	9.77	367.14
2034	1.06	543.33	9.74	363.64

Unit Montana 3	**Capacity Factor**	**Fuel Costs**	**Heat Rate**	**Fixed and Variable O&M**
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2016	0.90	239.46	9.81	240.58
2017	1.34	393.08	9.83	360.02
2018	2.24	773.21	9.88	384.44
2019	1.52	530.24	9.76	366.21
2020	1.70	603.27	9.75	372.02
2021	2.60	940.84	9.76	398.30
2022	0.56	209.94	9.81	341.34
2023	1.11	420.00	9.76	357.80
2024	0.75	291.42	9.73	347.69
2025	0.46	187.76	9.81	339.07
2026	0.59	246.15	9.79	343.49
2027	1.11	473.45	9.82	360.29
2028	0.05	22.12	9.73	326.68
2029	0.34	149.16	9.78	336.15

2030	0.12	55.78	9.78	329.20
2031	0.33	157.78	9.79	336.56
2032	0.38	187.02	9.78	338.54
2033	0.62	308.87	9.77	347.15
2034	0.58	299.82	9.76	346.29

Unit Montana 4	Capacity Factor	Fuel Costs	Heat Rate	Fixed and Variable O&M
Year	**%**	**$000**	**MMBtu/MWh**	**$000**
2017	0.55	160.36	9.83	232.45
2018	1.00	344.42	9.83	351.60
2019	0.78	273.33	9.80	346.16
2020	0.89	319.79	9.79	349.83
2021	1.36	493.65	9.78	363.40
2022	0.26	97.04	9.84	332.54
2023	0.57	214.40	9.80	341.69
2024	0.60	237.47	9.84	343.28
2025	0.21	85.98	9.84	331.43
2026	0.28	117.81	9.82	333.83
2027	0.49	209.88	9.86	340.59
2028	0.03	13.74	9.64	326.06
2029	0.17	74.41	9.79	330.57
2030	0.06	29.12	9.74	327.21
2031	0.17	78.38	9.79	330.75
2032	0.19	93.91	9.79	331.80
2033	0.32	160.00	9.78	336.47
2034	0.30	157.17	9.78	336.14

TABLE A-02 Purchased Power Costs

	Purchased Power
Year	**$/MWh**
2017	25.96
2018	29.50
2019	32.98
2020	39.44
2021	40.15
2022	40.89
2023	41.67
2024	42.36
2025	43.24
2026	44.06
2027	44.89
2028	45.74
2029	46.61
2030	47.49
2031	48.39
2032	49.30
2033	50.23
2034	51.18

TABLE A-03 Emission Rates and Water Consumption

2014 Emission Rates and Water Consumption: Based on Rolling Average						
Unit	**NOx[1] (lbs/kWh)**	**CO_2[3] (lbs/kWh)**	**CO[1] (lbs/kWh)**	**Hg (lbs/kWh)**	**SO_2[2] (lbs/kWh)**	**Water Consumption[4] (gal/year)**
Rio Grande 6	0.00221	1.38	0.00030	*	0.00001	203,079,222
Rio Grande 7	0.00149	1.27	0.00008	*	0.00001	124,658,004
Rio Grande 8	0.00201	1.27	0.00012	*	0.00001	458,118,166
Rio Grande 9	0.00009	1.08	0.00005	*	0.00001	33,753,988
Newman 1	0.00240	1.33	0.00032	*	0.00001	180,157,958
Newman 2	0.00171	1.29	0.00080	*	0.00001	164,120,158
Newman 3	0.00190	1.22	0.00028	*	0.00001	248,023,177
Newman 4**	0.00080	1.14	0.00024	*	0.000003	544,103,483
Newman 5***	0.00003	0.94	0.00003	*	0.000003	429,602,029
Copper 1	0.00423	2.01	0.00165	*	0.000003	3,819,242
Four Corners 4	0.00492	1.90	0.00028	0.0000059	0.001329	2,601,431,458
Four Corners 5	0.00529	2.06	0.00028	0.0000063	0.001596	2,601,431,458
Palo Verde 1	0	0	0	0	0	7,865,655,377
Palo Verde 2	0	0	0	0	0	7,981,299,897
Palo Verde 3	0	0	0	0	0	8,793,043,616

*No oil burned in 2014; therefore, no Hg emissions were created.

** Newman GT-1 and GT-2

*** Newman SC and CC 6A and 6B

1- Rio Grande, Newman, & Copper NOx & CO emission data from continuous emissions monitoring system.

2- Rio Grande, Newman, & Copper SO_2 emission data calculated from natural gas fuel sulfur content.

3- Rio Grande & Newman CO_2 emission data calculated as per 40 CFR 75 Appendix G Equation G-4; Copper as per 40 CFR 98 Subpart C.

4- Rio Grande & Newman water consumption data calculated based on maximum cooling tower rate and 2014 unit capacity factor

ATTACHMENT B – 2015 Long-Term and Budget Year Load Forecast

EL PASO ELECTRIC COMPANY
2015-2024 DEMAND AND ENERGY FORECAST
April 1, 2015

Summary

ENERGY (GWH)	2014 (1)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10-YR (6) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		9,314	9,482	9,690	9,896	10,100	10,301	10,506	10,718	10,936	11,155	
Expected:	8,258	8,445	8,589	8,770	8,944	9,112	9,274	9,438	9,608	9,780	9,953	**1.9**
Lower Bound		7,576	7,696	7,851	7,992	8,125	8,247	8,370	8,497	8,624	8,750	
Less: DG (3)		9	18	27	37	46	55	64	73	82	91	
Less: EE (4)		35	71	106	141	177	212	247	283	318	353	
Native System Energy												
Upper Bound		9,270	9,390	9,548	9,701	9,851	9,996	10,144	10,299	10,457	10,617	
Expected:	**8,258**	**8,401**	**8,500**	**8,637**	**8,766**	**8,890**	**9,007**	**9,127**	**9,252**	**9,380**	**9,508**	**1.4**
Lower Bound		7,532	7,610	7,726	7,831	7,928	8,018	8,109	8,205	8,303	8,399	
Total System Net Energy (5)												
Upper Bound		9,255	9,376	9,534	9,687	9,837	9,982	10,130	10,285	10,444	10,604	
Expected:	**8,174**	**8,392**	**8,491**	**8,628**	**8,757**	**8,881**	**8,998**	**9,118**	**9,243**	**9,371**	**9,499**	**1.5**
Lower Bound		7,528	7,607	7,723	7,827	7,925	8,014	8,105	8,201	8,299	8,395	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,058	2,096	2,151	2,200	2,248	2,289	2,340	2,388	2,436	2,478	
Expected:	1,766	1,812	1,838	1,882	1,919	1,955	1,984	2,025	2,062	2,099	2,130	**1.9**
Lower Bound		1,566	1,580	1,612	1,638	1,662	1,680	1,710	1,735	1,761	1,781	
Less: DG		3	5	8	10	13	15	18	21	23	26	
Less: EE		6	11	17	22	28	34	39	45	50	56	
Native System Demand:												
Upper Bound		2,050	2,079	2,125	2,164	2,202	2,233	2,274	2,311	2,348	2,379	
Expected:	**1,766**	**1,804**	**1,822**	**1,857**	**1,887**	**1,914**	**1,935**	**1,968**	**1,996**	**2,025**	**2,048**	**1.5**
Lower Bound		1,558	1,564	1,590	1,609	1,627	1,638	1,662	1,682	1,702	1,717	
Total System Demand												
Upper Bound		2,048	2,077	2,123	2,162	2,200	2,230	2,271	2,308	2,345	2,377	
Expected:	**1,764**	**1,802**	**1,820**	**1,856**	**1,885**	**1,913**	**1,934**	**1,966**	**1,994**	**2,023**	**2,046**	**1.5**
Lower Bound		1,557	1,563	1,588	1,607	1,625	1,637	1,661	1,681	1,701	1,716	
Interruptible Load		52	52	52	52	52	52	52	52	52	52	
Upper Bound		1,995	2,021	2,063	2,100	2,135	2,164	2,203	2,239	2,275	2,305	
Expected:	**1,764**	**1,750**	**1,768**	**1,803**	**1,832**	**1,860**	**1,881**	**1,914**	**1,942**	**1,971**	**1,994**	**1.2**
Lower Bound		1,504	1,514	1,543	1,565	1,585	1,599	1,625	1,645	1,667	1,683	

Footnotes:

(1) 2014 are Actual data, Native System Peak occurred on June 4th.

(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) Total System includes transmission wheeling Losses To Others.
(6) 10-Year Compounded Average Growth Rate.

/s/ Rocky Miracle

Rocky Miracle
Senior Vice President, Corporate Planning & Development
and Chief Compliance Officer

EL PASO ELECTRIC COMPANY
2025-2034 DEMAND AND ENERGY FORECAST
April 1, 2015

Summary

ENERGY (GWH)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20-YR (1) CAGR
Native System Forecast (NFL)											
Upper Bound	11,378	11,604	11,835	12,072	12,310	12,555	12,789	13,034	13,286	13,542	
Expected:	10,127	10,303	10,484	10,669	10,854	11,044	11,222	11,411	11,606	11,805	**1.8**
Lower Bound	8,876	9,003	9,133	9,265	9,397	9,534	9,655	9,789	9,927	10,067	
Less: DG	100	110	119	128	137	146	155	164	173	183	
Less: EE	389	424	424	424	424	424	424	424	424	424	
Native System Energy:											
Upper Bound	10,779	10,944	11,150	11,363	11,578	11,802	12,015	12,241	12,475	12,714	
Expected:	**9,638**	**9,770**	**9,942**	**10,117**	**10,293**	**10,474**	**10,643**	**10,823**	**11,009**	**11,198**	**1.5**
Lower Bound	8,497	8,595	8,733	8,871	9,007	9,146	9,270	9,404	9,542	9,682	
Total System Net Energy:											
Upper Bound	10,766	10,931	11,137	11,350	11,565	11,790	12,003	12,229	12,463	12,702	
Expected:	**9,629**	**9,761**	**9,933**	**10,108**	**10,284**	**10,465**	**10,634**	**10,814**	**11,000**	**11,189**	**1.6**
Lower Bound	8,492	8,591	8,728	8,866	9,002	9,141	9,265	9,399	9,537	9,677	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,532	2,581	2,631	2,675	2,732	2,785	2,834	2,880	2,939	2,994	
Expected:	2,173	2,211	2,250	2,283	2,329	2,370	2,408	2,442	2,490	2,533	**1.8**
Lower Bound	1,814	1,841	1,868	1,891	1,926	1,955	1,982	2,004	2,041	2,072	
Less: DG	28	31	33	36	39	41	44	46	49	52	
Less: EE	61	67	73	78	84	89	95	101	106	112	
Native System Demand:											
Upper Bound	2,422	2,460	2,499	2,532	2,578	2,619	2,658	2,692	2,741	2,784	
Expected:	**2,083**	**2,113**	**2,144**	**2,169**	**2,206**	**2,239**	**2,269**	**2,295**	**2,335**	**2,370**	**1.5**
Lower Bound	1,744	1,765	1,788	1,805	1,835	1,859	1,881	1,898	1,930	1,956	
Total System Demand:											
Upper Bound	2,420	2,458	2,496	2,530	2,576	2,617	2,655	2,689	2,738	2,781	
Expected:	**2,081**	**2,111**	**2,142**	**2,167**	**2,205**	**2,237**	**2,267**	**2,293**	**2,334**	**2,368**	**1.5**
Lower Bound	1,743	1,764	1,787	1,804	1,834	1,858	1,880	1,897	1,929	1,955	
Interruptible Load:	52	52	52	52	52	52	52	52	52	52	
Upper Bound	2,347	2,385	2,423	2,456	2,501	2,542	2,580	2,614	2,663	2,705	
Expected:	**2,029**	**2,059**	**2,089**	**2,115**	**2,152**	**2,185**	**2,215**	**2,241**	**2,281**	**2,316**	**1.4**
Lower Bound	1,711	1,733	1,756	1,773	1,804	1,828	1,850	1,868	1,900	1,926	

Footnotes:

(1) 20-Year Compounded Average Growth Rate.

ATTACHMENT C – Lazard's Levelized Cost of Energy Analysis –Version 8.0

SEPTEMBER 2014

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 8.0

LAZARD

Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- Comparative "levelized cost of energy" for various technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel costs, geography and cost of capital, among other factors
- Comparison of the implied cost of carbon abatement given resource planning decisions for various generation technologies
- Illustration of how the cost of utility-scale and rooftop solar-produced energy compares against generation rates in large metropolitan areas of the United States
- Illustration of utility-scale and rooftop solar versus peaking generation technologies globally
- Illustration of how the costs of utility-scale and rooftop solar and wind vary across the United States, based on average available resources
- Forecast of rooftop solar levelized cost of energy through 2017
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the levelized cost of energy for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense, and fuel cost, as relevant
- Considerations regarding the usage characteristics and applicability of various generation technologies, taking into account factors such as location requirements/constraints, dispatch capability, land and water requirements and other contingencies
- Summary assumptions for the various generation technologies examined
- Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies

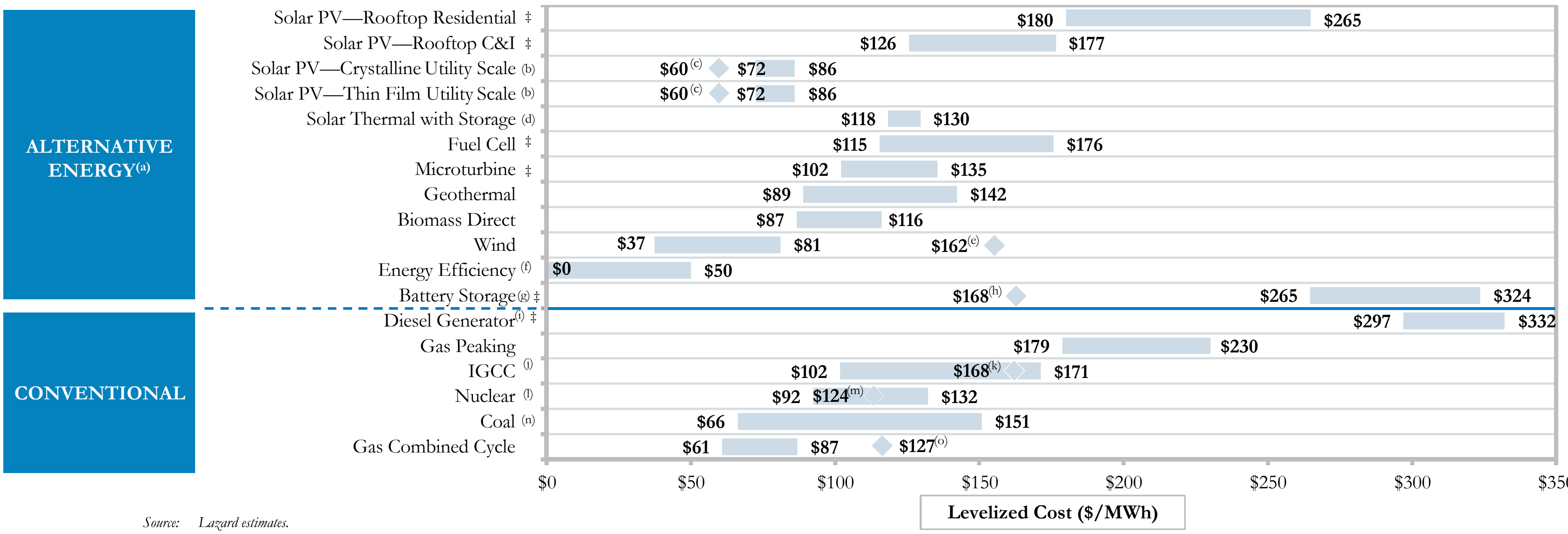
Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.)

While prior versions of this study have presented the LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present the LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies"

Note: This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or other advice.

Unsubsidized Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies)



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

(a) Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from $2.00 to $10.00 per MWh.

(b) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(c) Diamonds represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

(d) Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

(e) Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

(f) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

(g) Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

(h) Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

(i) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

(j) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

(k) Represents estimate of current U.S. new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

(l) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

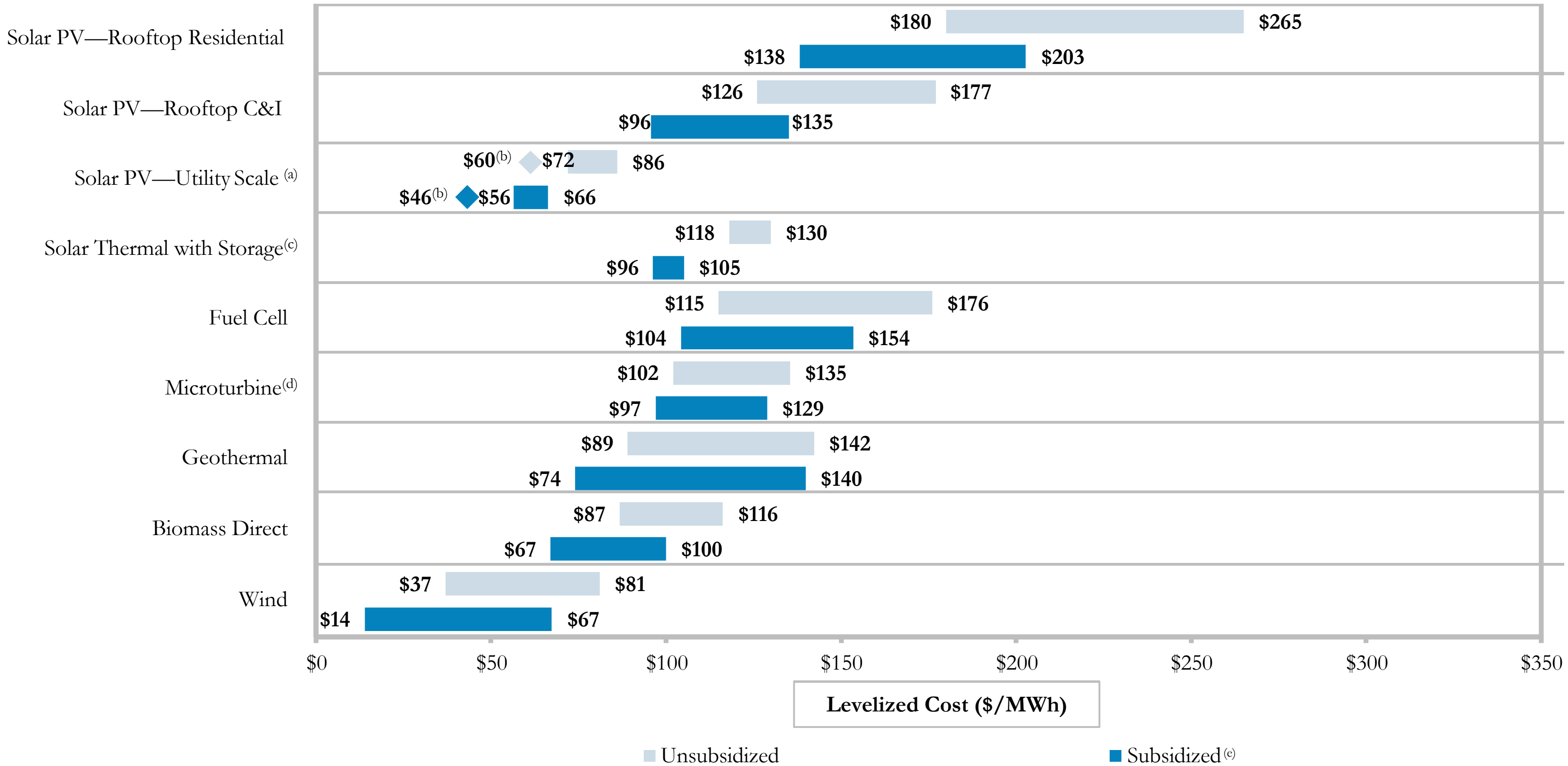
(m) Represents estimate of current U.S. new nuclear construction.

(n) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

(o) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies

U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are, generally, currently important in all regions); while some Alternative Energy generation technologies have achieved notional "grid parity" under certain conditions (e.g., best-in-class wind/solar resource), such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.) or reliability-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy generation technologies)



Source: Lazard estimates.

(a) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW fixed-tilt installation in high insolation jurisdiction (e.g., Southwest U.S.).

(b) Diamonds represent estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

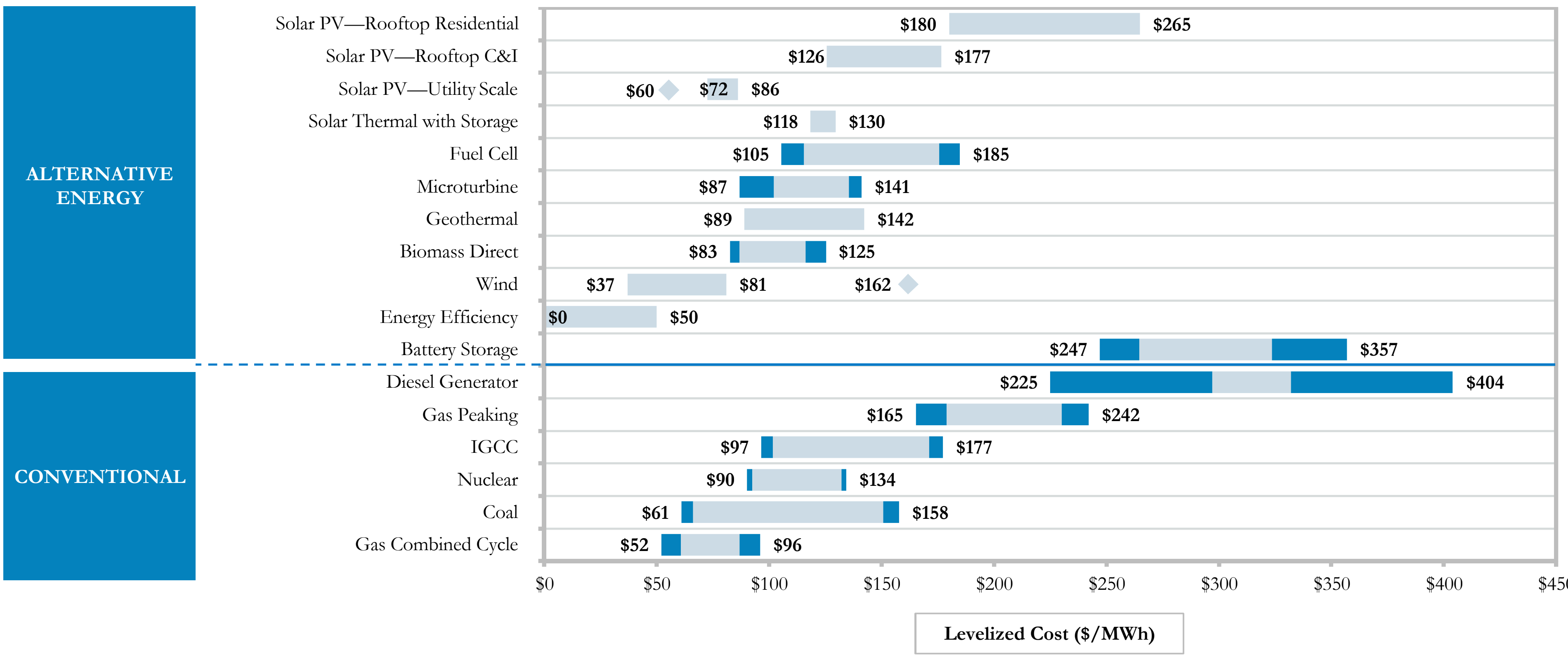
(c) Low end represents concentrating solar tower with 18-hour storage. High end represents concentrating solar tower with 10-hour storage capability.

(d) Reflects 10% Investment Tax Credit. Capital structure adjusted for lower Investment Tax Credit; assumes 50% debt at 8.0% interest rate, 20% tax equity at 12.0% cost and 30% common equity at 12.0% cost.

(e) Except where noted, reflects 30% Investment Tax Credit. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 12.0% cost and 20% common equity at 12.0% cost.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: Lazard estimates.
Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations.

Cost of Carbon Abatement Comparison

As policymakers consider the best and most cost-effective ways to limit carbon emissions (including in the U.S., in respect of Section 111(d) regulations), they should consider the implicit costs of carbon abatement of various Alternative Energy generation technologies; an analysis of such implicit costs suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost effective way of limiting carbon emissions; rooftop solar and solar thermal remain expensive, by comparison

- **Such observation does not take into account potential social and environmental externalities or reliability-related considerations**

		CONVENTIONAL GENERATION			ALTERNATIVE ENERGY RESOURCES			
	Units	Coal[(b)]	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop	Solar PV Utility Scale[(c)]	Solar Thermal[(d)] with Storage
Capital Investment/KW of Capacity[(a)]	$/kW	$3,000	$1,006	$5,385	$1,400	$3,500	$1,750	$9,800
Total Capital Investment	**$mm**	**$1,800**	**$805**	**$3,339**	**$1,498**	**$8,505**	**$3,255**	**$6,860**
Memo: Total ITC/PTC Tax Subsidization	$mm	—	—	—	$449	$2,552	$977	$2,058
Facility Output	**MW**	**600**	**800**	**620**	**1,070**	**2,430**	**1,860**	**700**
Capacity Factor	%	93%	70%	90%	52%	23%	30%	80%
Effective Facility Output	**MW**	**558**	**558**	**558**	**558**	**558**	**558**	**558**
MWh/Year Produced[(e)]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$66	$61	$92	$37	$180	$72	$118
Total Cost of Energy Produced	**$mm/yr**	**$324** 2	**$298**	**$452**	**$183**	**$880**	**$354** 1	**$579**
Carbon Emitted	mm Tons/yr	4.54	1.92	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.62	4.54	4.54	4.54	4.54 3	4.54
vs. Gas		—	—	1.92	1.92	1.92	1.92	1.92
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($26)	$128	($141)	$557	$31 4	$255
vs. Gas		—	—	$154	($115)	$582	$57	$281
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($10)	$28	($31)	$123	$7 5	$56
vs. Gas		—	—	$80	($60)	$304	$30	$147

Source: Lazard estimates.

Note: Does not reflect production tax credit or investment tax credit. Assumes 2014 dollars, 20 – 40 year economic life, 40% tax rate and 5 – 40 year tax life. Assumes 2.5% annual escalation for O&M costs and fuel prices. Inputs for each of the various technologies are those associated with the low end levelized cost of energy.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) Based on advanced supercritical pulverized coal. Does not incorporate carbon capture and compression.

(c) Represents single-axis tracking.

(d) Low end represents concentrating solar tower with 18-hour storage capability.

(e) All facilities sized to produce 4,888 GWh/yr.

Illustrative Implied Carbon Abatement Cost Calculation:

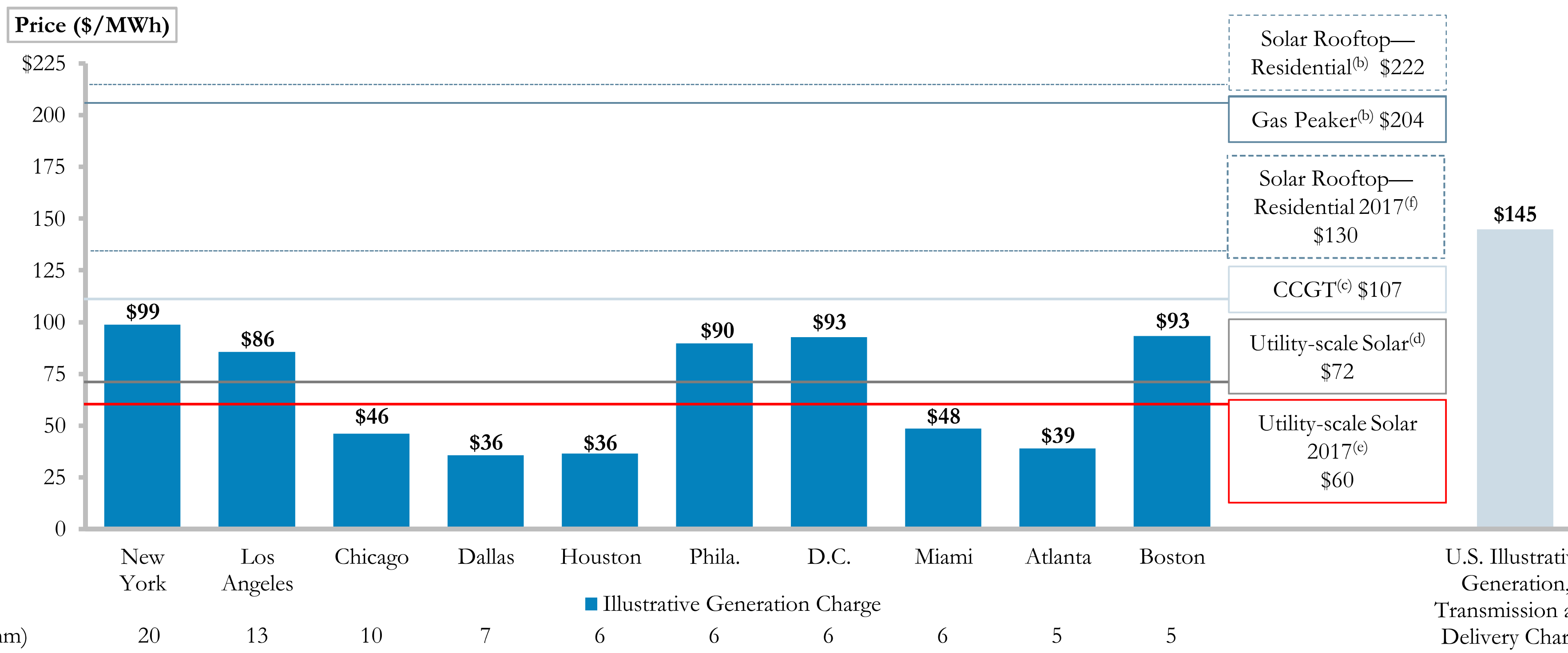
4 Difference in Total Energy Cost vs. Coal = 1 – 2
= $354 mm/yr (solar) – $324 mm/yr (coal) = $31 mm/yr

5 Implied Abatement Cost vs. Coal = 4 ÷ 3
= $31 mm/yr ÷ 4.54 mm Tons/yr = $7/Ton

Generation Rates for the 10 Largest U.S. Metropolitan Areas[a]

Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, utility-scale solar is becoming a more economically viable peaking energy product in many areas of the U.S. and, as pricing declines, could become economically competitive across a broader array of geographies

- **Such observation does not take into account potential social and environmental externalities or reliability-related considerations**

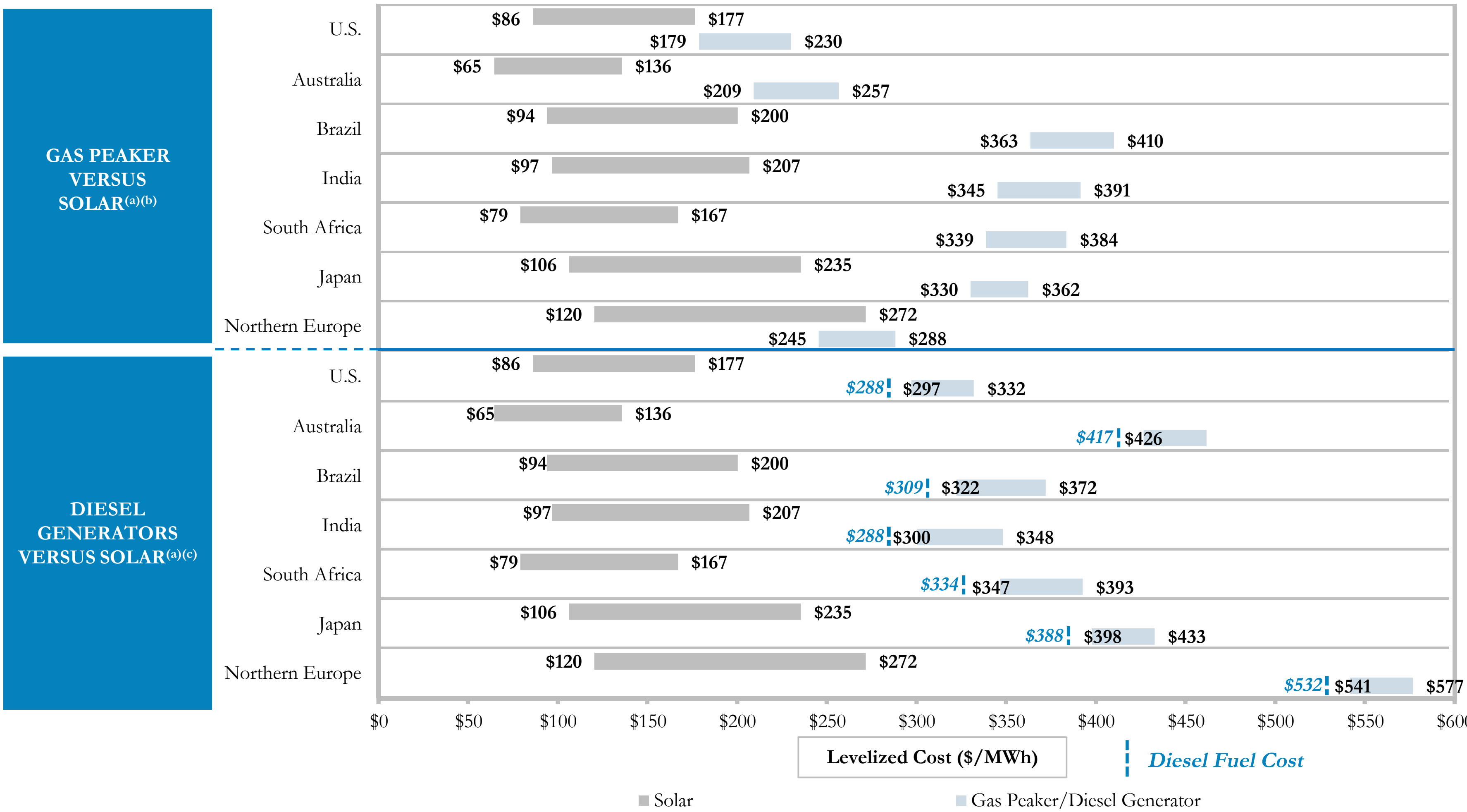


Metropolitan Statistical Area	New York	Los Angeles	Chicago	Dallas	Houston	Phila.	D.C.	Miami	Atlanta	Boston
Population (mm)	20	13	10	7	6	6	6	6	5	5
Cumulative % of U.S. population[g]	6%	11%	14%	16%	18%	20%	22%	23%	25%	27%

Source: *EEI, Ventyx.*
Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio.
(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of 83 million.
(b) Represents an average of the high and low levelized cost of energy.
(c) Assumes 25% capacity factor.
(d) Represents low end of utility-scale solar. Excludes investment tax credit.
(e) Represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system. Excludes investment tax credit.
(f) Represents estimated implied levelized cost of energy in 2017, assuming $2.20 per watt (average of high and low).
(g) Represents 2013 census data.

Solar versus Peaking Capacity—Global Markets

Solar PV can be an attractive resource relative to gas and diesel-fired peaking in many parts of the world due to high fuel costs; without storage, however, solar lacks the dispatch characteristics of conventional peaking technologies



Source: World Bank, IHS Waterborne LNG, Department of Energy of South Africa, Sydney and Brisbane Hub Trading Prices and Lazard estimates.

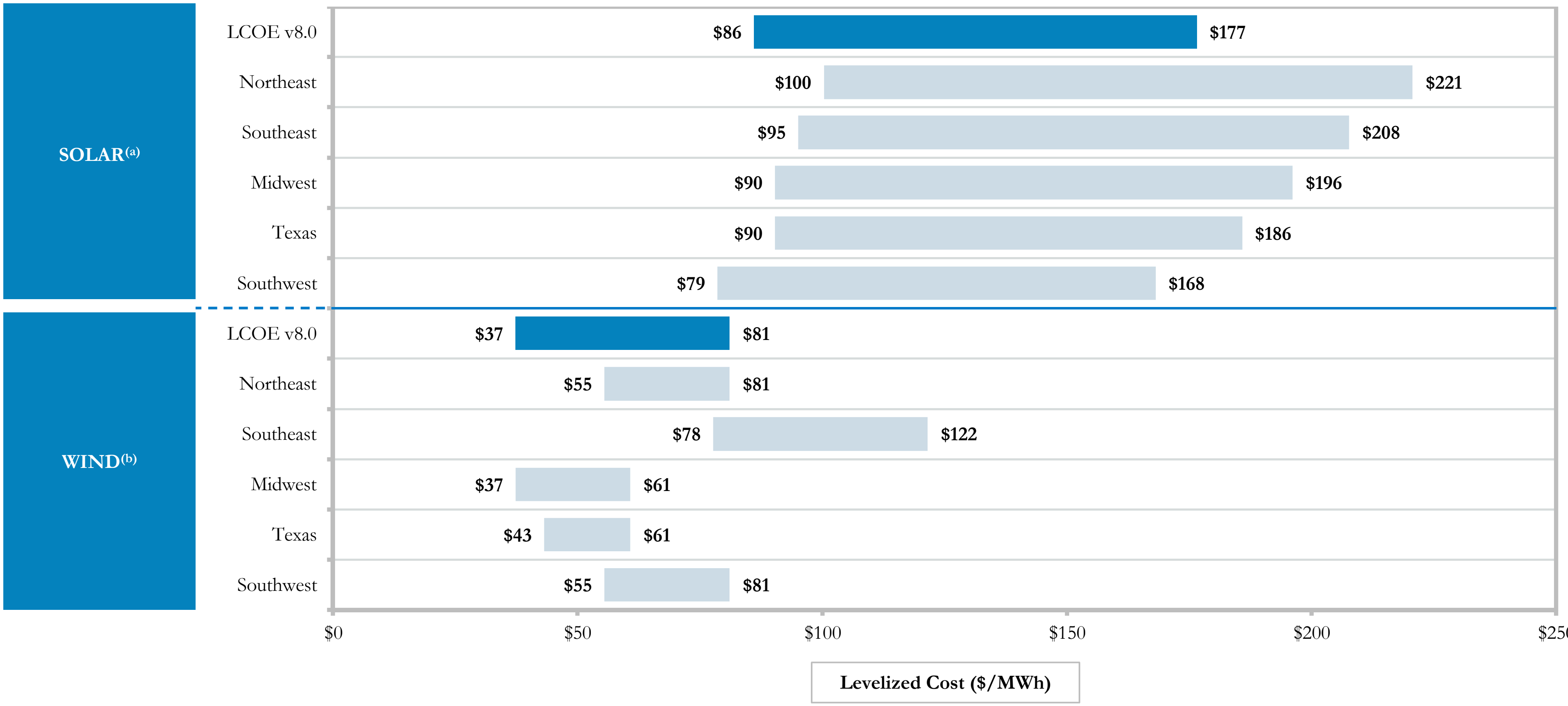
(a) Low end assumes a solar fixed-tilt utility-scale system with per watt capital costs of $1.50. High end assumes a solar rooftop C&I system with per watt capital costs of $3.00. Solar projects assume capacity factors of 26% – 28% for Australia, 25% – 27% for Brazil, 23% – 25% for India, 27% – 29% for South Africa, 15% – 17% for Japan and 13% – 15% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(b) Assumes natural gas prices of $7 for Australia, $16 for Brazil, $15 for India, $15 for South Africa, $17 for Japan and $10 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 30% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $15 per KW/year, heat rate of 10,000 Btu/KWh and total capital costs of $500 to $800 per KW of capacity. Assumes diesel prices of $5.80 for Australia, $4.30 for Brazil, $4.00 for India, $4.65 for South Africa, $5.40 for Japan and $7.40 for Northern Europe (all in U.S.$ per gallon).

Wind and Solar Resource—U.S. Regional Sensitivity (Unsubsidized)

The availability of wind and solar resource has a meaningful impact on the levelized cost of energy for various regions of the United States. This regional analysis varies capacity factors as a proxy for resource availability, while holding other variables constant. There are a variety of other factors (e.g., transmission, back-up generation/system reliability costs, labor rates, permitting and other costs) that would also impact regional costs



Source: *Lazard estimates.*

Note: Assumes solar capacity factors of 16% – 18% for the Northeast, 17% – 19% for the Southeast, 18% – 20% for the Midwest, 19% – 20% for Texas and 21% – 23% for the Southwest. Assumes wind capacity factors of 30% – 35% for the Northeast, 20% – 25% for the Southeast, 40% – 52% for the Midwest, 40% – 45% for Texas and 30% – 35% for the Southwest.

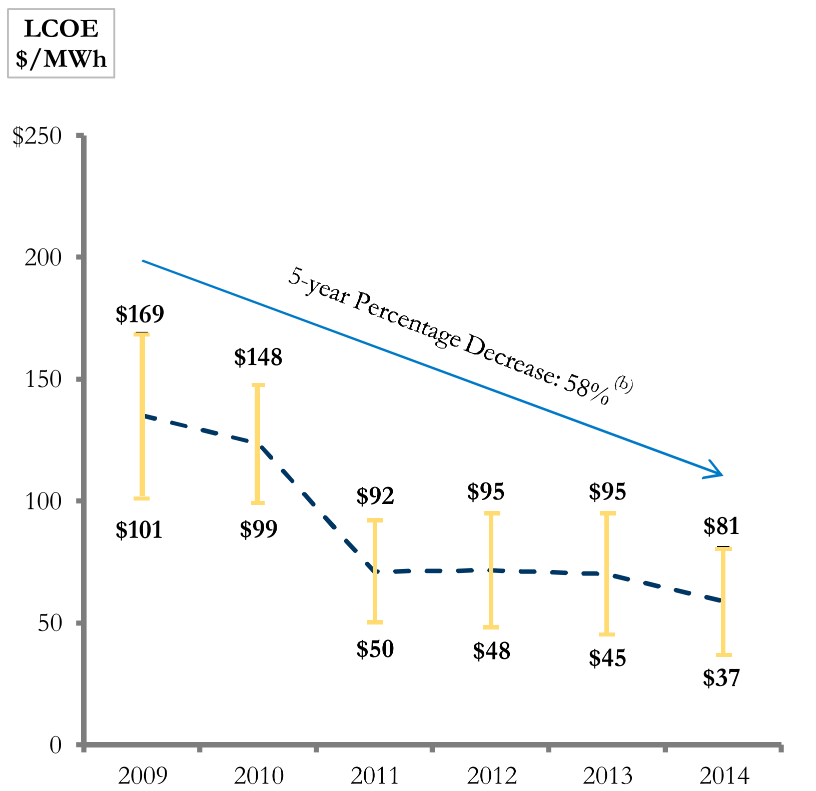
(a) Low end assumes a solar fixed-tilt utility-scale system with per watt capital costs of $1.50. High end assumes a solar rooftop C&I system with per watt capital costs of $3.00.

(b) Assumes an onshore wind generation plant with capital costs of $1.40 – $1.80 per watt.

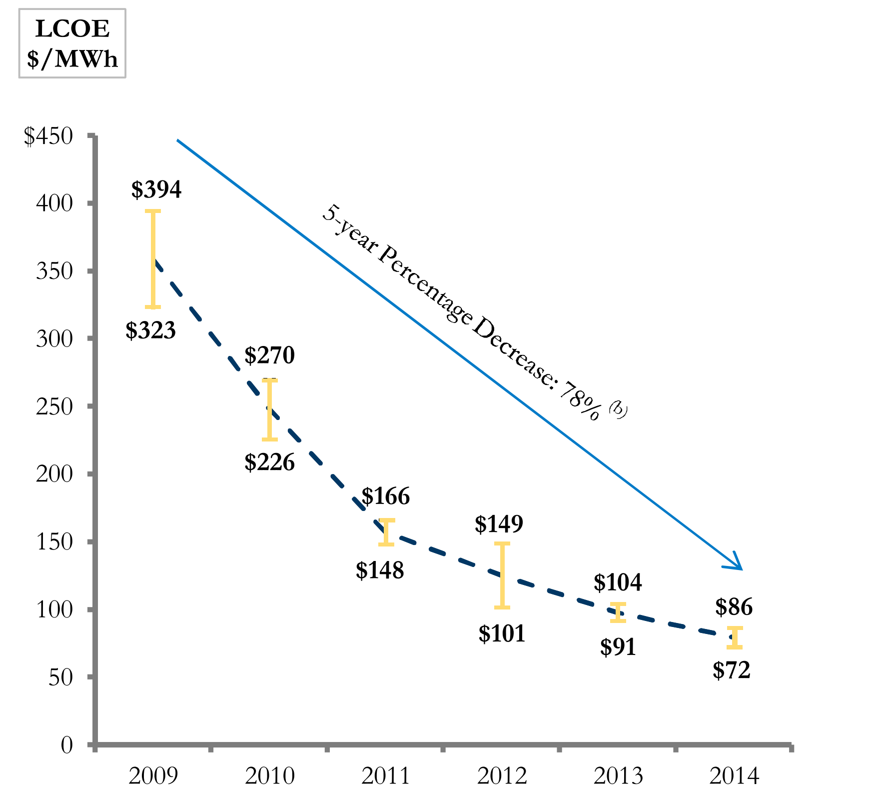
Levelized Cost of Energy—Wind/Solar PV (Historical)

Over the last five years, wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

WIND LCOE



SOLAR PV LCOE [(a)]



LCOE   LCOE Range

Source: *Lazard estimates.*

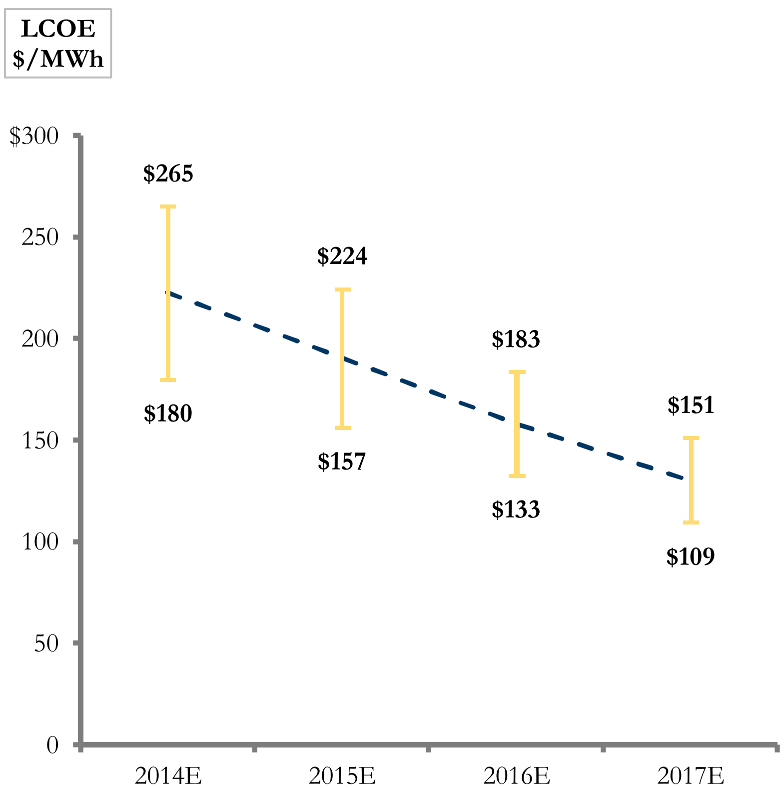
(a) Represents LCOE range of utility-scale crystalline solar PV. High end represents fixed installation, while low end represents single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.).

(b) Represents average percentage decrease of high and low of LCOE range.

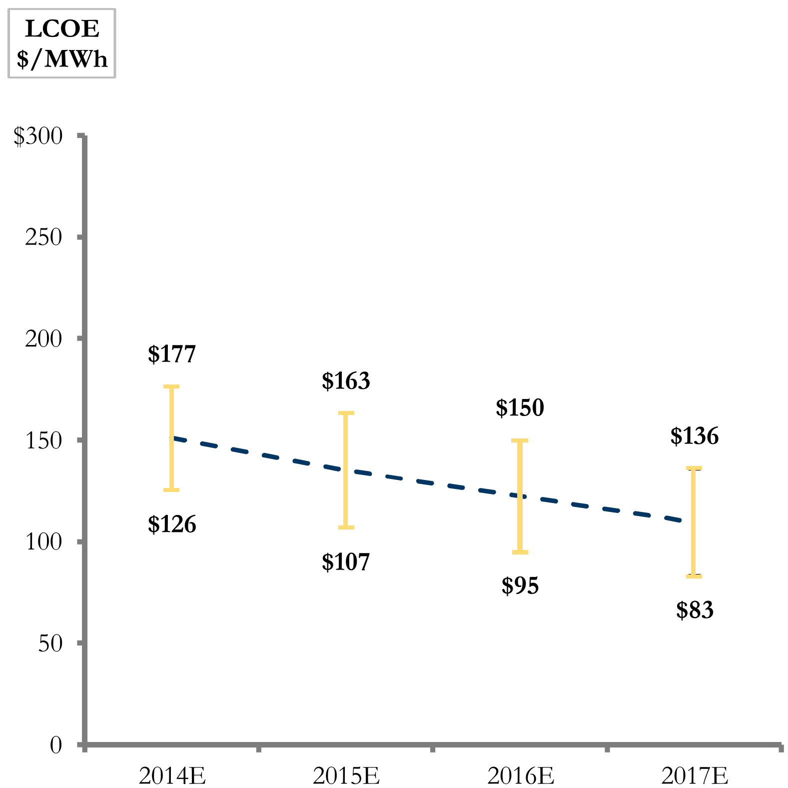
Levelized Cost of Energy—Rooftop Solar (Forecasted)

Rooftop solar has benefited from the rapid decline in price of both panels and key balance-of-system components (e.g., inverters, racking, etc.); while the small-scale nature and added complexity of rooftop installation limit cost reduction levels (vs. levels observed in utility-scale applications), more efficient installation techniques, lower costs of capital and improved supply chains will contribute to a lower rooftop solar LCOE over time

ROOFTOP RESIDENTIAL LCOE(a)



ROOFTOP C&I LCOE(b)

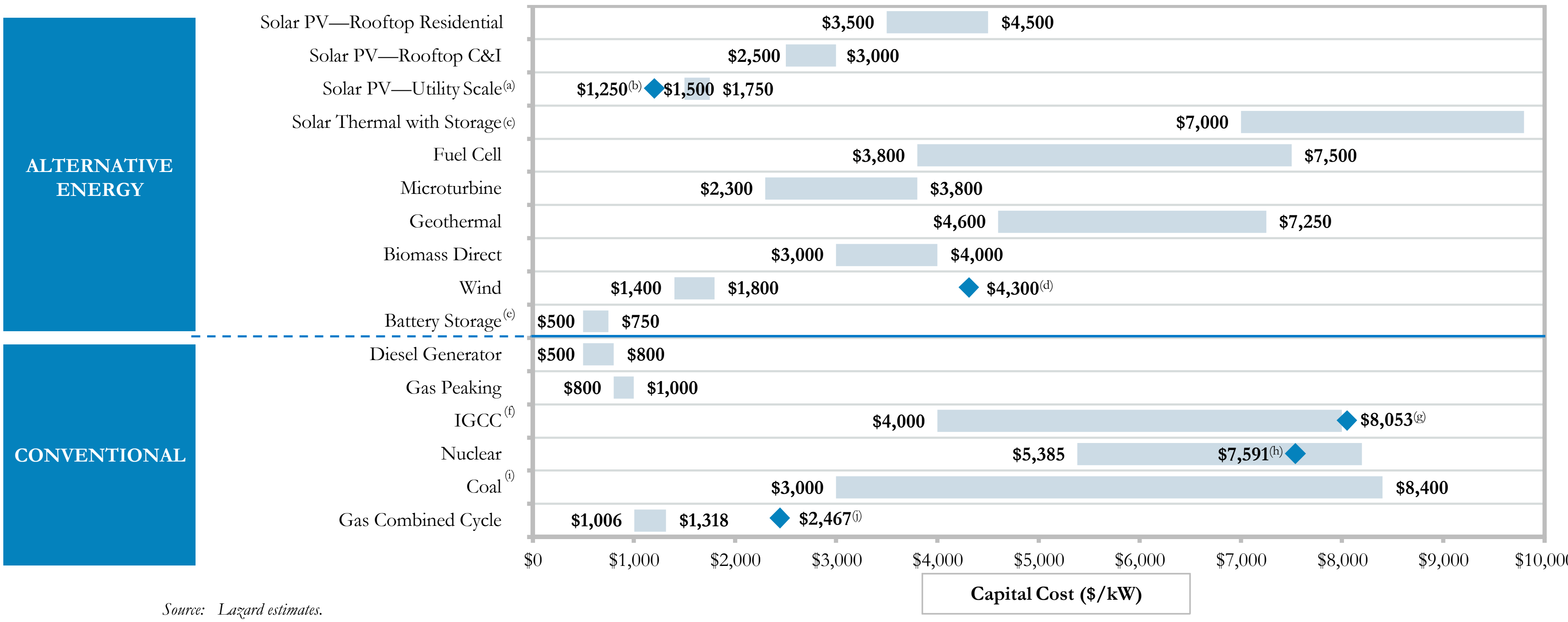


Rooftop Solar LCOE — Rooftop Solar LCOE Range

Source: Lazard estimates, BNEF and Wall Street research.
Note: Assumes capacity factors of 20% – 23%.
(a) Represents total high-end capital costs per watt of $4.50, $3.75, $3.00 and $2.40 and total low-end capital costs per watt of $3.50, $3.00, $2.50 and $2.00 over 2014 – 2017, respectively. Assumes fixed O&M of $25 – $30 per kW/year for 2014 – 2017.
(b) Represents total high-end capital costs per watt of $3.00, $2.75, $2.50 and $2.25 and total low-end capital costs per watt of $2.50, $2.10, $1.85 and $1.60 over 2014 – 2017, respectively. Assumes fixed O&M of $13 – $20 per kW/year for 2014 – 2017.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of some conventional generation technologies (e.g., gas), declining costs for many Alternative Energy generation technologies, coupled with rising long-term construction and uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies

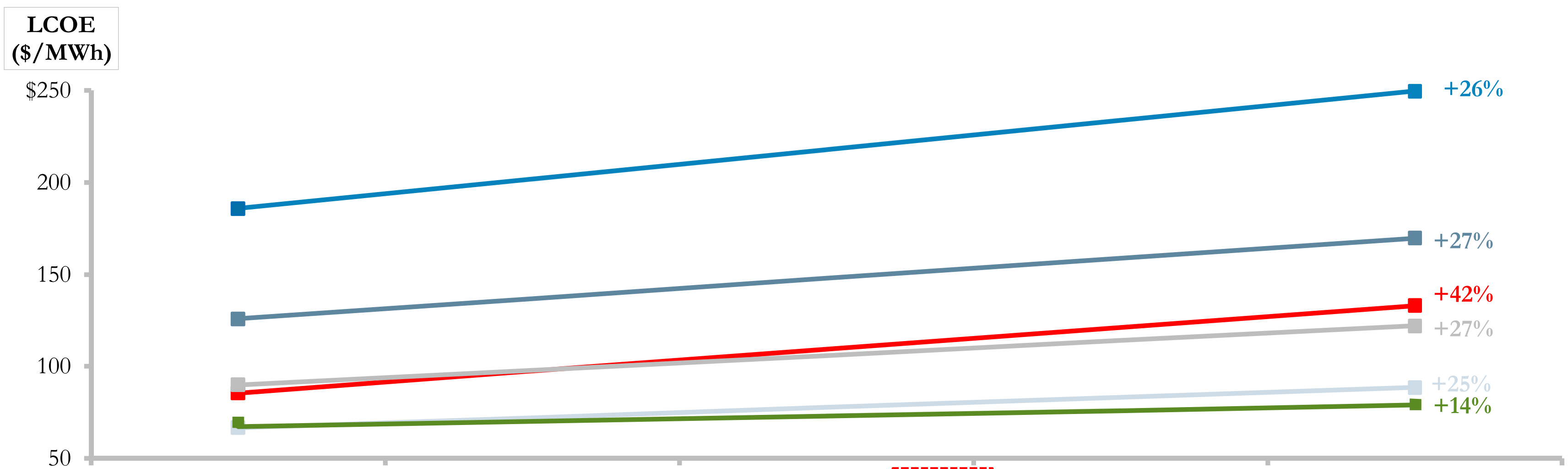


Source: Lazard estimates.

(a) High end represents single-axis tracking. Low end represents fixed-tilt installation.
(b) Diamond represents estimated capital costs in 2017, assuming $1.25 per watt for a single-axis tracking system.
(c) Low end represents concentrating solar tower with 10-hour storage capability. High end represents concentrating solar tower with 18-hour storage capability.
(d) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.
(e) Indicative range based on current stationary storage technologies.
(f) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(g) Represents estimate of current U.S. new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.
(h) Represents estimate of current U.S. new nuclear construction.
(i) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(j) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies resulting from the potential for intermittently disrupted capital markets (and the relatively immature state of some aspects of financing Alternative Energy technologies) is the impact of the availability and cost of capital[(a)] on their LCOEs; availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them



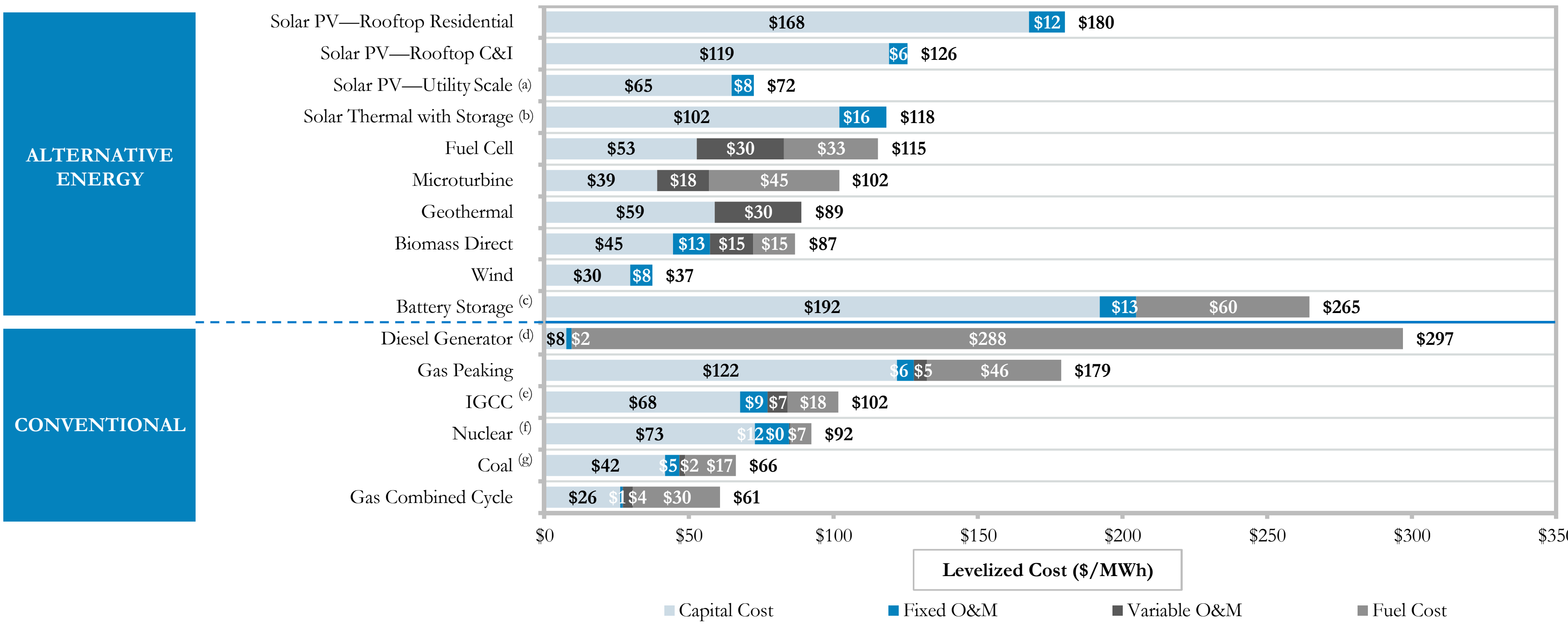
After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Solar PV—Rooftop Residential
Solar PV—Rooftop C&I
Solar PV—Utility Scale[(b)]
Nuclear[(c)]
Coal[(d)]
Gas—Combined Cycle
Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy Analysis

Source: Lazard estimates.
(a) Cost of capital associated with the particular Alternative Energy generation technology (not the cost of capital of the investor/developer).
(b) Assumes a fixed-tilt Solar PV utility-scale system with capital costs of $1.50 per watt.
(c) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(d) Based on advanced supercritical pulverized coal.

Levelized Cost of Energy Components—Low End

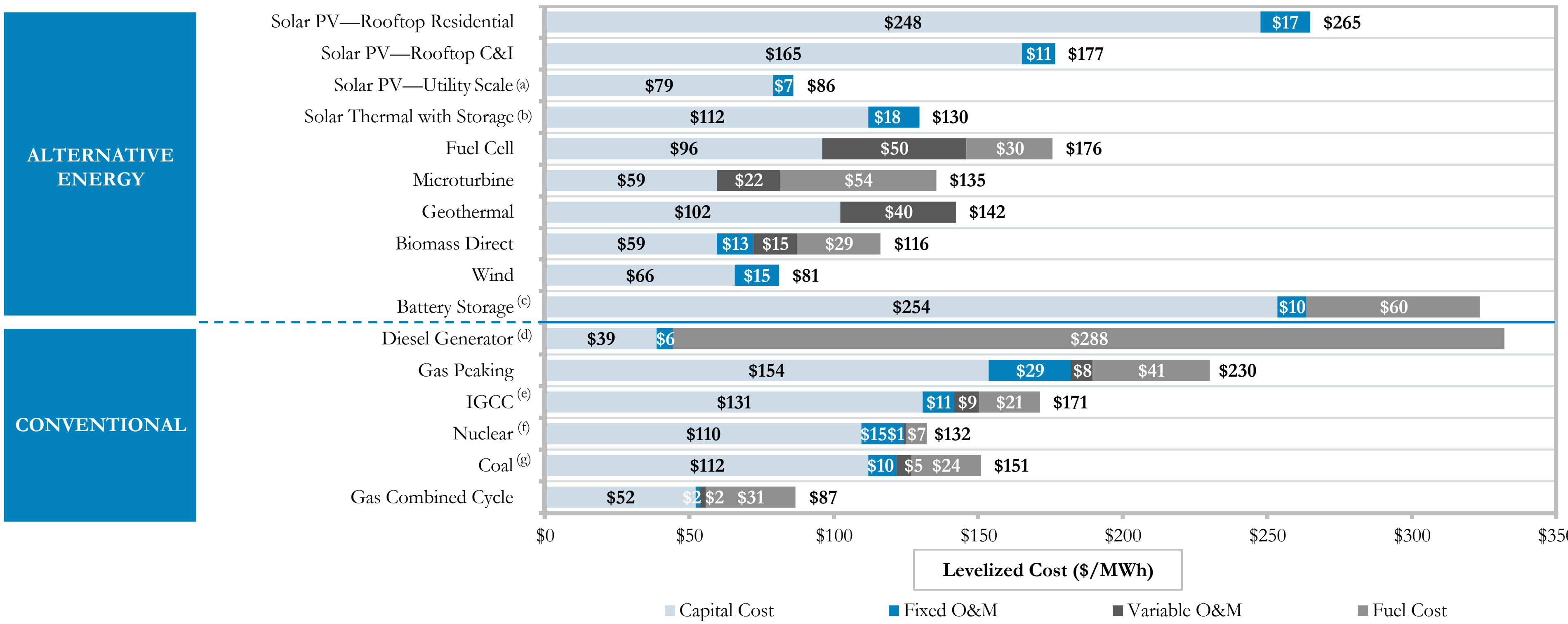
Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)



Source: Lazard estimates.
(a) Low end represents single-axis tracking.
(b) Low end represents concentrating solar tower with 18-hour storage capability.
(c) Low end represents lead acid battery.
(d) Low end represents continuous operation.
(e) Does not incorporate carbon capture and compression.
(f) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(g) Based on advanced supercritical pulverized coal. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)



Source: Lazard estimates.

(a) High end represents fixed-tilt installation.
(b) High end represents concentrating solar tower with 10-hour storage capability.
(c) High end represents NaS technology.
(d) High end represents intermittent operation.
(e) High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(f) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(g) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	CUSTOMER LOCATED	CENTRAL STATION	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	SOLAR PV	$72 – 265[(a)]	✓	Commercial	✓	✓	Universal[(b)]	✓	✓		
	SOLAR THERMAL	$118 – 130[(a)]	✓	Commercial		✓	Southwest	✓	✓	✓	
	FUEL CELL	$115 – 176	?	Emerging/ Commercial	✓		Universal				✓
	MICROTURBINE	$102 – 135	?	Emerging/ Commercial	✓		Universal				✓
	GEOTHERMAL	$89 – 142	✓	Mature		✓	Varies				✓
	BIOMASS DIRECT	$87 – 116	✓	Mature		✓	Universal			✓	✓
	ONSHORE WIND	$37 – 81	✓	Mature		✓	Varies	✓			
	BATTERY STORAGE	$265 – 324	✓	Emerging	✓	✓	Varies		✓	✓	
CONVENTIONAL	DIESEL GENERATOR	$297 – 332	×	Mature	✓		Universal	✓	✓	✓	✓
	GAS PEAKING	$179 – 230	×	Mature	✓	✓	Universal		✓	✓	
	IGCC	$102 – 171	×[(c)]	Emerging[(d)]		✓	Co-located or rural				✓
	NUCLEAR	$92 – 132	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$66 – 151	×[(c)]	Mature[(d)]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$61 – 87	×	Mature	✓	✓	Universal			✓	✓

Source: Lazard estimates.
(a) LCOE study capacity factor assumes Southwest location.
(b) Qualification for RPS requirements varies by location.
(c) Could be considered carbon neutral technology, assuming carbon capture and compression.
(d) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy—Key Assumptions

		Solar PV					
	Units	Rooftop—Residential	Rooftop—C&I	Utility Scale—Crystalline[c]	Utility Scale—Thin Film[c]	Solar Thermal Tower with Storage[d]	Fuel Cell
Net Facility Output	MW	0.005	1	10	10	75 – 110	2.4
EPC Cost	$/kW	$3,500 – $4,500	$2,500 – $3,000	$1,750 – $1,500	$1,750 – $1,500	$8,750 – $6,250	$3,000 – $7,500
Capital Cost During Construction	$/kW	induded	induded	induded	induded	$1,050 – $750	induded
Other Owner's Costs	$/kW	induded	induded	induded	induded	induded	$800 – induded
Total Capital Cost[a]	$/kW	$3,500 – $4,500	$2,500 – $3,000	$1,750 – $1,500	$1,750 – $1,500	$9,800 – $7,000	$3,800 – $7,500
Fixed O&M	$/kW-yr	$25.00 – $30.00	$13.00 – $20.00	$20.00 – $13.00	$20.00 – $13.00	$115.00 – $80.00	—
Variable O&M	$/MWh	—	—	—	—	—	$30 – $50
Heat Rate	Btu/kWh	—	—	—	—	—	7,260 – 6,600
Capacity Factor	%	23% – 20%	23% – 20%	30% – 21%	30% – 21%	80% – 52%	95%
Fuel Price	$/MMBtu	—	—	—	—	—	$4.50
Construction Time	Months	3	3	12	12	30	3
Facility Life	Years	20	20	20	20	40	20
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	0 – 117
Investment Tax Credit[b]	%	—	—	—	—	—	—
Production Tax Credit[b]	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$180 – $265	$126 – $177	$72 – $86	$72 – $86	$118 – $130	$115 – $176

Source: *Lazard estimates.*

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."

(c) Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(d) Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Microturbine	Geothermal	Biomass Direct	Wind	Off-Shore Wind	Battery Storage[c]
Net Facility Output	MW	1	30	35	100	210	6
EPC Cost	$/kW	$2,300 – $3,800	$4,021 – $6,337	$2,622 – $3,497	$1,100 – $1,400	$2,500 – $4,620	$500 – $750
Capital Cost During Construction	$/kW	included	$579 – $913	$378 – $503	included	included	included
Other Owner's Costs	$/kW	included	included	included	$300 – $400	$600 – $880	included
Total Capital Cost[a]	$/kW	$2,300 – $3,800	$4,600 – $7,250	$3,000 – $4,000	$1,400 – $1,800	$3,100 – $5,500	$500 – $750
Fixed O&M	$/kW-yr	—	—	$95.00	$35.00 – $40.00	$60.00 – $100.00	$27.50 – $22.00
Variable O&M	$/MWh	$18.00 – $22.00	$30.00 – $40.00	$15.00	—	$13.00 – $18.00	—
Heat Rate	Btu/kWh	10,000 – 12,000	—	14,500	—	—	—
Capacity Factor	%	95%	90% – 80%	85%	52% – 30%	43% – 37%	25% – 25%
Fuel Price	$/MMBtu	$4.50	—	$1.00 – $2.00	—	—	$60[c]
Construction Time	Months	3	36	36	12	12	3
Facility Life	Years	20	20	20	20	20	20
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	—
Investment Tax Credit[b]	%	—	—	—	—	—	—
Production Tax Credit[b]	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$102 – $135	$89 – $142	$87 – $116	$37 – $81	$110 – $214	$265 – $324

Source: Lazard estimates.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."

(c) Assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Generator[c]	Gas Peaking	IGCC[d]	Nuclear[e]	Coal[f]	Gas Combined Cycle
Net Facility Output	MW	2	216 – 103	580	1,100	600	550
EPC Cost	$/kW	$500 – $800	$580 – $700	$3,257 – $6,390	$3,750 – $5,250	$2,027 – $6,067	$743 – $1,004
Capital Cost During Construction	$/kW	included	included	$743 – $1,610	$1,035 – $1,449	$487 – $1,602	$107 – $145
Other Owner's Costs	$/kW	included	$220 – $300	included	$600 – $1,500	$486 – $731	$156 – $170
Total Capital Cost[a]	$/kW	$500 – $800	$800 – $1,000	$4,000 – $8,000	$5,385 – $8,199	$3,000 – $8,400	$1,006 – $1,318
Fixed O&M	$/kW-yr	$15.00	$5.00 – $25.00	$62.25 – $73.00	$95.00 – $115.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	—	$4.70 – $7.50	$7.00 – $8.50	$0.25 – $0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	10,000	10,300 – 9,000	8,800 – 10,520	10,450	8,750 – 12,000	6,700 – 6,900
Capacity Factor	%	95% – 30%	10%	75%	90%	93%	70% – 40%
Fuel Price	$/MMBtu	$28.76	$4.50	$1.99	$0.70	$1.99	$4.50
Construction Time	Months	3	25	57 – 63	69	60 – 66	36
Facility Life	Years	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 – 117	117	169	—	211	117
Investment Tax Credit[b]	%	—	—	—	—	—	—
Production Tax Credit[b]	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$297 – $332	$179 – $230	$102 – $171	$92 – $132	$66 – $151	$61 – $87

Source: *Lazard estimates.*
(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 8.0 present LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies."
(c) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.
(d) High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and government subsidies in certain regions.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, and economic life) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and U.S. federal tax incentives on the levelized cost of energy. These inputs were developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This study (as well as previous versions) has benefitted from additional input from a wide variety of industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.).

ATTACHMENT D: Expansion Plan Results – Base Case and Sensitivities

TABLE D-01a
Base Case

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)
	10PV(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)	10PV(1)		10PV(1)		10PV(1)		10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031	10PV(1)	10PV(1)	10PV(1)	20PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
						20PV(1)	10PV(1)	
2033	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2034		LMS (1)			10PV(1)			10PV(1)
P.V. UTILITY COST:	**4,463,904**	**4,464,397**	**4,464,495**	**4,464,733**	**4,464,741**	**4,464,765**	**4,464,915**	**4,464,980**

TABLE D-01b
Solar Higher Capital Cost Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030				10PV(1)		10PV(1)		10PV(1)
2031	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)
					LMS (1)			
2033			20PV(1)					20PV(1)
2034	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	20PV(1)	LMS (2)	LMS (1)
		LMS (1)				LMS (1)		
P.V. UTILITY COST:	**4,474,195**	**4,475,032**	**4,475,769**	**4,476,246**	**4,476,577**	**4,477,087**	**4,477,391**	**4,477,828**

TABLE D-01c
Low Load Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2024	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
2026	LMS (1)	20PV(1)	20PV(1)	LMS (1)	LMS (1)	20PV(1)	LMS (1)	LMS (1)
	10PV(1)	LMS (1)	LMS (1)	10PV(1)	10PV(1)	LMS (1)	10PV(1)	10PV(1)
2027	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
	10PV(1)			10PV(1)	10PV(1)		10PV(1)	10PV(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031						10PV(1)	10PV(1)	
2032	10PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)			10PV(1)
2033	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	20PV(1)
								LMS (1)
2034			10PV(1)	20PV(1)		10PV(1)	20PV(1)	
P.V. UTILITY COST:	**4,240,565**	**4,240,754**	**4,240,975**	**4,241,008**	**4,241,077**	**4,241,147**	**4,241,180**	**4,241,286**

TABLE D-01d
High Load Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
2024	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2025	LMS (2)	LMS (2)	LMS (2)	LMS (2)	LMS (2)	LMS (2)	LMS (2)	LMS (2)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2027								
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029				10PV(1)			10PV(1)	20PV(1)
2030	10PV(1)	10PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)	20PV(1)	
2031	20PV(1)	20PV(1)	20PV(1)	10PV(1)	20PV(1)	20PV(1)		10PV(1)
2032	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	10PV(1)	20PV(1)	20PV(1)
2033	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
			10PV(1)		10PV(1)			
2034		10PV(1)			10PV(1)	10PV(1)	10PV(1)	10PV(1)
P.V. UTILITY COST:	**4,486,028**	**4,486,277**	**4,486,431**	**4,486,445**	**4,486,681**	**4,486,692**	**4,486,893**	**4,486,937**

TABLE D-01e
Low Natural Gas Price Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)
	10PV(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)	10PV(1)		10PV(1)		10PV(1)		10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031	10PV(1)	10PV(1)	10PV(1)	20PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2033						20PV(1)	10PV(1)	
2034	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
		LMS (1)			10PV(1)			10PV(1)
P.V. UTILITY COST:	**4,145,093**	**4,145,645**	**4,145,812**	**4,146,083**	**4,146,088**	**4,146,095**	**4,146,304**	**4,146,358**

TABLE D-01f

High Natural Gas Price Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)
	10PV(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)	10PV(1)		10PV(1)		10PV(1)		10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031	10PV(1)	10PV(1)	10PV(1)	20PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2033						20PV(1)	10PV(1)	
2034	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
		LMS (1)			10PV(1)			10PV(1)
P.V. UTILITY COST:	**4,499,168**	**4,499,655**	**4,499,746**	**4,499,980**	**4,499,989**	**4,500,014**	**4,500,158**	**4,500,223**

TABLE D-01g
$8 CO2 Tax Price Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	11BR(1)	20PV(1)	20PV(1)	11BR(1)	11BR(1)	20PV(1)	11BR(1)
	10PV(1)	10PV(1)	11BR(1)	11BR(1)	10PV(1)	10PV(1)	11BR(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)	10PV(1)			10PV(1)	10PV(1)		10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031	10PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)	10PV(1)	10PV(1)	20PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2033						20PV(1)	10PV(1)	
2034	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
		LMS (1)		10PV(1)				10PV(1)
P.V. UTILITY COST:	**4,640,444**	**4,640,904**	**4,640,944**	**4,641,175**	**4,641,176**	**4,641,225**	**4,641,323**	**4,641,406**

TABLE D-01h
$20 CO2 Tax Price Sensitivity

PLAN RANK	1	2	3	4	5	6	7	8
2022	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)	11GR(1)
2023								
2024	11BR(1)	20PV(1)	11BR(1)	20PV(1)	11BR(1)	11BR(1)	20PV(1)	11BR(1)
	10PV(1)	11BR(1)	10PV(1)	11BR(1)	10PV(1)	10PV(1)	11BR(1)	10PV(1)
2025	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2026	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
	10PV(1)		10PV(1)		10PV(1)	10PV(1)		10PV(1)
2027	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)	20PV(1)
	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)	WIND(1)
2028	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)	11BR(1)
2029								
2030								
2031	10PV(1)	10PV(1)	10PV(1)	10PV(1)	20PV(1)	10PV(1)	10PV(1)	20PV(1)
2032	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
2033						20PV(1)	10PV(1)	
2034	LMS (1)	LMS (1)	20PV(1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)	LMS (1)
			LMS (1)	10PV(1)				10PV(1)
P.V. UTILITY COST:	**4,906,233**	**4,906,597**	**4,906,644**	**4,906,802**	**4,906,820**	**4,906,894**	**4,906,915**	**4,907,025**

ATTCHMENT E: 20-Year Loads and Resources Document for Recommended Plan

							1x1 CC		10 MW PV 1x1 CC	20 MW PV LMS100
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
1.0 GENERATION RESOURCES										
1.1 RIO GRANDE	275	275	275	275	275	229	229	229	229	229
1.2 NEWMAN	782	782	782	782	782	782	699	553	405	308
1.3 FOUR CORNERS	108	-	-	-	-	-	-	-	-	-
1.4 COPPER	64	64	64	64	64	64	64	64	64	64
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633	633
1.6 RENEWABLES	1	1	1	1	1	1	1	1	1	1
1.7 NEW BUILD (local)	264	352	352	352	352	352	633	633	924	1,032
1.0 TOTAL GENERATION RESOURCES [1]	**2,127**	**2,107**	**2,107**	**2,107**	**2,107**	**2,061**	**2,259**	**2,113**	**2,256**	**2,267**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	29	29	29	29	28	28	28	28	27	27
2.2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	35	35	34	34	34	34	34	34	33	33
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	7	7	7	7	7	7
2.5 RESOURCE PURCHASE	-	-	-	-		70	-	85	-	-
2.0 TOTAL RESOURCE PURCHASES [2]	**74**	**73**	**73**	**72**	**72**	**142**	**71**	**156**	**70**	**70**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,201**	**2,180**	**2,180**	**2,179**	**2,179**	**2,203**	**2,330**	**2,269**	**2,326**	**2,337**
4.0 SYSTEM DEMAND										
4.1 NATIVE SYSTEM DEMAND	**1,852**	**1,896**	**1,933**	**1,969**	**1,998**	**2,039**	**2,076**	**2,113**	**2,144**	**2,187**
4.2 DISTRIBUTED GENERATION	(19)	(22)	(25)	(27)	(29)	(31)	(34)	(37)	(39)	(42)
4.3 ENERGY EFFICIENCY	(11)	(17)	(22)	(28)	(34)	(39)	(45)	(50)	(56)	(61)
4.4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4.5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.5)) [3]	**1,768**	**1,803**	**1,832**	**1,860**	**1,881**	**1,914**	**1,942**	**1,971**	**1,994**	**2,029**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**433**	**377**	**348**	**319**	**298**	**289**	**388**	**298**	**332**	**308**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	**265**	**270**	**275**	**279**	**282**	**287**	**291**	**296**	**299**	**304**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**168**	**107**	**73**	**40**	**16**	**2**	**97**	**2**	**33**	**4**

	10 MW PV LMS100 2026	20 MW PV WIND 2027	1x1 CC 2028	2029	2030	10 MW PV 2031	LMS100 2032	2033	LMS100 2034
1.0 GENERATION RESOURCES									
1.1 RIO GRANDE	229	229	87	87	87	87	87	87	87
1.2 NEWMAN	308	308	308	308	308	308	308	308	308
1.3 FOUR CORNERS	-	-	-	-	-	-	-	-	-
1.4 COPPER	-	-	-	-	-	-	-	-	-
1.5 PALO VERDE	633	633	633	633	633	633	633	633	633
1.6 RENEWABLES	1	1	1	1	1	1	1	1	1
1.7 NEW BUILD (local)	1,130	1,172	1,453	1,453	1,453	1,463	1,551	1,551	1,639
1.0 TOTAL GENERATION RESOURCES [1]	**2,301**	**2,343**	**2,482**	**2,482**	**2,482**	**2,492**	**2,580**	**2,580**	**2,668**
2.0 RESOURCE PURCHASES									
2.1 RENEWABLE PURCHASE (SunEdison & NRG)	27	27	27	26	26	26	26	26	25
2.2 RENEWABLE PURCHASE (Hatch)	3	3	3	3	3	3	3	3	3
2.3 RENEWABLE PURCHASE (Macho Springs)	33	33	33	33	32	32	32	32	32
2.4 RENEWABLE PURCHASE (Juwi)	7	7	7	7	6	6	6	6	6
2.5 RESOURCE PURCHASE	-	-	-	10	-	-	5	-	5
2.0 TOTAL RESOURCE PURCHASES [2]	**69**	**69**	**69**	**78**	**68**	**67**	**72**	**67**	**71**
3.0 TOTAL NET RESOURCES (1.0 + 2.0)	**2,370**	**2,412**	**2,551**	**2,560**	**2,550**	**2,559**	**2,652**	**2,647**	**2,739**
4.0 SYSTEM DEMAND									
4.1 NATIVE SYSTEM DEMAND	2,225	2,263	2,297	2,343	2,384	2,422	2,456	2,504	2,547
4.2 DISTRIBUTED GENERATION	(44)	(46)	(49)	(52)	(55)	(57)	(59)	(63)	(64)
4.3 ENERGY EFFICIENCY	(67)	(73)	(78)	(84)	(89)	(95)	(101)	(106)	(112)
4.4 LINE LOSSES	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
4.5 INTERRUPTIBLE SALES	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
5.0 TOTAL SYSTEM DEMAND (4.1-(4.2+4.3+4.4+4.5)) [3]	**2,059**	**2,089**	**2,115**	**2,152**	**2,185**	**2,215**	**2,241**	**2,281**	**2,316**
6.0 MARGIN OVER TOTAL DEMAND (3.0 - 5.0)	**312**	**323**	**436**	**408**	**365**	**345**	**411**	**366**	**423**
7.0 PLANNING RESERVE 15% OF TOTAL SYSTEM DEMAND	**309**	**313**	**317**	**323**	**328**	**332**	**336**	**342**	**347**
8.0 MARGIN OVER RESERVE (6.0 - 7.0)	**3**	**9**	**119**	**86**	**37**	**12**	**75**	**24**	**76**

EPE has written a summary of the Public Advisory Group's (PAG's) input to EPE's 2015 Integrated Resource Plan (IRP) and has asked PAG participants for comments.

According to EPE's 2012 IRP document, EPE must, in its IRP process, "evaluate renewable energy, energy efficiency, load management, distributed generation and conventional supply-side resources on a consistent and comparable basis and take into consideration risk and uncertainty of fuel supply, price volatility and costs of anticipated environmental regulations."[1] Unfortunately EPE has, in the current IRP process, concentrated on supply-side resources and has not evaluated load management on "a consistent and comparable basis".

EPE offers a residential TOU rate where the on-peak period is 8 hours per day, Monday through Friday, six months per year – a total of over 1,000 hours per year. From the residential ratepayer's perspective, reducing usage significantly every weekday afternoon and evening for half the year to avoid on-peak charges is too onerous; too restrictive a requirement to make the rate worthwhile and, as a consequence, few residential ratepayers have chosen this TOU rate (~62 out of ~82,000). And EPE does not need 1,000 hours of reduced usage to cut the peak significantly. Analysis of 15 minute load data for 2011 through 2013 (EPE "declines"[2] to furnish 15 minute load data for 2014) "shows that the top 10% of EPE's annual peak load occurred during about 100 hours per year.

A TOU rate combined with curtailment whenever EPE's load exceeds 90% of peak was proposed during the PAG IRP process as a realistic way to reduce peak demand. The proposed rate would narrow the time period during which the consumer was asked to reduce usage, and increase both the penalty for on-peak use, and the reward for shifting load off-peak. EPE was asked to model this rate along with supply-side alternatives to determine its relative merits. But despite repeated requests, EPE "declines"[3] to model the proposed rate.

Based on EPE's Loads and Resources document, EPE will be asking the PRC to consider new generation in the next few years. If a TOU/curtailment rate were to be proposed as part of the current rate case (15-00127-UT), it could be placed into use soon enough that the evaluation of the results could have an impact on the next round of proposed new power plants. There would be little cost to EPE to implement the proposed new rate beyond metering and billing changes.

[1] EPE's 2012 IRP, p5
[2] EPE's 24 April 2015 letter to Jason Marks
[3] EPE's 24 April 2015 letter to Jason Marks

But EPE's approach has been to propose an RFP process that will probably take two or more years before a new rate could be offered. Evidence of the rate's effectiveness would not be available when the next round of power plants is considered.

Although we advocated a load management approach in the public IRP process based primarily on rate design, which EPE declined to model, EPE appears to have modeled a vendor based demand management program. Although this approach appeared to be more cost effective than supply expansions, it was inexplicably not selected as part of the preferred portfolio. In the "20-Year Expansion Plan Results" handout for the 7 May 2015 IRP PAG meeting, EPE predicted that Demand Response would have a capital cost of $64/kW. Since EPE is rewarded for building or buying new assets, and not for reducing peak demand and improving the system load factor, delaying the implementation of a peak load management strategy, and then implementing one with a $64/kW capital cost, is to the advantage of EPE's shareholders; but not its ratepayers.

We believe it is time for some dramatic changes in the way EPE is regulated. EPE is a for-profit company and a regulated public utility charged with delivering reliable electric service to its customers at a reasonable price. The formula by which EPE is rewarded for providing this service is based solely on the amount of money EPE invests in assets.

If EPE, in the best interests of its customers, enters into a purchased power agreement (PPA), it is not rewarded for that decision; a PPA involves no new capital expenditures, so no additional reward.

If EPE designs a rate structure that discourages power usage at peak times thereby reducing or delaying the need for expenditures for new generation, EPE is penalized; the profit EPE would receive from investing in that new generation is delayed or eliminated.

We would support EPE and the PRC in any effort to revise the way in which EPE is rewarded to better align the interests of EPE's shareholders with those of EPE's rate payers.

For the present we have to work within the existing framework which rewards EPE only for solutions that involve new capital assets. But that framework does require that EPE develop a cost effective resource portfolio *including load management and distributed generation*. EPE has recently built new generation that will increase its rate base, if approved, by over $600 million and its annual profit, if its 9.95% after tax return on equity is approved, by over $49 million, which is great for shareholders. We ask that EPE also honor its obligation to ratepayers by implementing aggressive load management rates that will provide ratepayers the opportunity to significantly reduce their electric bill by shifting their load away from peak, and will benefit all rate payers in the longer term by avoiding or delaying the need for new generation facilities.

We would also note that the power generation industry is changing rapidly; renewables including solar and technologies such as battery storage are rapidly becoming cost effective. Other technologies, such as thorium reactors, are not ready today but hold promise for the future. They deserve ongoing consideration and perhaps EPE's involvement and investment in their development. Don't keep building conventional gas fired power plants that should still be operational 40 or 50 years into the future, but may become obsolete long before then.

We urge EPE to implement peak load reduction rates now and to adopt renewable and innovative supply side alternatives in the future.

Based on EPE's approach to public participation and demand management solutions in the IRP, EPE's intended path is totally pro-investor and severely anti-customer. We would support changes to better align EPE's financial incentives with customers' long term interest in avoiding unnecessary plant investment, including both positive and negative incentives.

Please include this input with the IRP filing.

Rocky Bacchus

Stephen Fischmann

Allen Downs

Public Advisory Group Input from Merrie Lee Soules – June 29, 2015

There are several concerns with EPE's IRP to be filed in July, 2015. As a participant in the Public Advisory Process, I tried several times to address these concerns as part of the process, with little success. This document is to clearly identify my input to EPE's 2015 IRP. Following are my concerns with the process and its results. I also state my own conclusions.

First, the entire need for new generation capacity over the next 10 years or more is driven by unit retirements, not by demand growth. Second, the Loads and Resources (L&R) Table that EPE shared with the Public Advisory Group on May 15, 2015 and represented as the L&R without expansion, does not include all of the resources involved with EPE's current regulatory filings and resources. Third, EPE continues to use an assumption of a 15% capacity reserve margin while other utilities are using a 13% assumption. Fourth, EPE laments the falling Load Factor, but proposes nothing to change that trend, at the same time opposing rapid introduction of a Demand Response program proposed by one of the public participants which would do just that.

The foundational material of the IRP is the Loads and Resources Table. EPE shared detail of some parts of the information represented in the L&R, but very limited detail for other parts. I have reconstructed the L&R Table (see Exhibit 1) to more accurately represent the current situation. My assumption is that each decision point, retirement, new build, forecast assumptions, etc., will be clearly justified in the planning process. Following are the individual assumptions that I made. Each of these is also identified as a comment in the Table:

- Rio Grande capacity includes Rio Grande 6, 7, 8, and 9, equal to 321 MW, throughout the period as no economic analysis or justification for retirements has been provided. Rio Grande 6 is currently in inactive, reserved status. It remains available capacity, it has been one of EPE's more reliable generating units, and EPE stated in one of the Public Advisory Group meetings that its retirement and replacement would certainly raise the Revenue Requirement.
- Newman capacity remains at 782 MW throughout the period as no economic analysis or justification for retirements has been provided
- The Renewables line in generation resources shows a continuous 3 MW as was shown in EPE's 2012 L&R Table in the IRP filing. It also includes the 20 MW of Solar at Ft Bliss and the 5 MW of Solar at Holloman for which EPE has filed for a CCN. Both of these units were downgraded to 70% of the total capacity. The additional 3MW of Solar being pursued at Montana is not shown because the CCN has not yet been filed. But it is also not part of the IRP results and proposal.
- For the Native System Demand, this L&R Table uses the lower of the forecasts between the 3/10/15 forecast in the Ft Bliss filing and the 5/7/15 forecast that was provided to the Public Advisory Group. EPE provided no explanation for why its future year forecast changed to include so much more growth.
- For its energy efficiency initiatives whose forecast is captured on the CMCOG line, EPE provided no explanation for why the forecast doesn't continue to improve. EPE also didn't address what it would take to increase the amount of energy savings beyond the forecast level. This chart is more optimistic in the years 2020 and beyond.

- The EPE L&R of 5/7/15 shows line losses of 2 MW.
- EPE's L&R of 2/5/15 shows interruptible sales of 62 MW. EPE claims that they lost a customer which reduced their forecast for interruptible sales and that they intend to continue to reduce the customers in this rate category. This chart assumes continuing interruptible sales at the level of 62 MW, although higher levels should be possible.
- The customer owned solar line starts with the value of 15MW in 2015, 19MW in 2016 (from EPE's L&R of 5/7/15),then increases by 3MW each year. This is conservative given the growth in customer owned solar in recent years which shows no slowing. EPE refuses to address how to further encourage this growth.
- Planning Reserve is set at 13%

The result of changing these key assumptions is that EPE does not require new generation capacity until the year 2026.

The entire need for new generation capacity over the next 10 years or more is driven by unit retirements, not by demand growth. From 17.7.3 NMAC Integrated Resource Plans for Electric Utilities, para 17.7.3.5, the objective of the IRP is "…to identify the most cost effective portfolio of resources to supply energy needs of customers. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts." Para 17.7.3.7 provides the following definition: "**most cost effective resource portfolio** means those supply-side resources and demand-side resources that *minimize the net present value of revenue requirements* proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations". This is a clear prescription for how to evaluate options. The portfolio of resource options needs to include the option of continuing to run older units past the date of full depreciation. Except for the abandonment of 108 MW at Four Corners where justification is provided in the PRC filing, EPE has either not done this analysis or has refused to share it with the Public Advisory Group.

The Loads and Resources (L&R) Table that EPE shared with the Public Advisory Group on May 15, 2015 and represented as the L&R without expansion, does not include all of the resources involved with EPE's current regulatory filings and resources. Apparently, the solar capacity that has been requested for Fort Bliss, Holloman, and Montana, and the Rio Grande 6 capacity that is currently available as reserve were not modeled in the Strategist simulation. Therefore, the results of the simulation do not represent the complete picture.

EPE continues to use an assumption of a 15% capacity reserve margin while other utilities are using a 13% assumption. This affects the timing of when supply side resources might be inadequate. 13% is a reasonable reserve margin.

EPE laments the falling Load Factor, but proposes nothing to change that trend, at the same time opposing rapid introduction of a Demand Response program proposed by one of the public participants which would do just that – change the trend. The proposed program is a realistic way to reduce peak demand by combining a Time of Use rate with curtailment whenever EPE's load exceeds 90% of peak. The proposed rate would narrow the time period during which the consumer was asked to reduce usage, and increase both the penalty for on-peak use, and the reward for shifting load off-peak. EPE was repeatedly asked to model this rate, along with supply-side alternatives to determine its relative merits, but continues to decline to do so. This proposal would cost EPE little to implement, but it is dependent on an appropriate rate structure. Implemented promptly, this program could effectively increase the Load Factor and delay the need for new generating capacity.

Conclusion 1

- Given that the already approved Montana 4 generating unit is forecasted to have at least a 45 year life, EPE and New Mexico have already committed our grandchildren to be paying for fossil fuel based electricity generation until 2062; and
- Given that climate change is a reality; and
- Given that burning of fossil fuels is a key driver of climate change; and
- Given that the 10 year window before EPE requires additional capacity is a unique and timely opportunity;

El Paso Electric and the New Mexico Public Regulation Commission, as part of the EPE 2015 Integrated Resource Plan, should establish the principle that there will be **No New Fossil Fuel Based Generating Capacity** going forward.

Conclusion 2

- Given that EPE as an investor owned utility is guaranteed a profit based on return on net investment, called Rate Base; and
- Given that EPE is thereby rewarded for replacing old assets with new assets; and
- Given that EPE profits increase when the load factor decreases; and
- Given that EPE has little incentive to adopt pricing policies that encourage energy conversation during peak hours; and
- Given that EPE has little incentive to run energy efficiency programs effectively; and
- Given that EPE has little incentive to develop technologies for energy storage, generation, or grid management; and
- Given that EPE has little incentive to pursue distributed generation potential;

The New Mexico Public Regulation Commission should shift to a **Revenue Formula That Rewards Efficient Use of Assets.**

This summarizes my input as part of the EPE Public Advisory Group for the 2015 IRP. Please include it with the IRP filling. Respectfully submitted,

Merrie Lee Soules

Loads and Resources - El Paso Electric

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation Resources																	
	Rio Grande	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321
	Newman	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782	782
	Four Corners	108	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Copper	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
	Palo Verde	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633	633
	Renewables	3	3	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	Montana	176	264	352	352	352	352	352	352	352	352	352	352	352	352	352	352
Total Generation Resources		2087	2175	2172	2172	2172	2172	2172	2172	2172	2172	2172	2172	2172	2172	2172	2172
	Market Block Purchase																
	Renewable Purchase (SunEd & NRG)	37	37	37	37	37	36	36	36	36	36	36	36	36	36	36	36
	Renewable Purchase (Hatch)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
	Renewable Purchase (Biomass)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Renewable Purchase (Macho Springs)	35	35	35	34	34	34	34	34	34	33	33	33	33	33	33	33
	Renewable Purchase (Juwi)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Resource Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Resource Purchases		83	83	83	82	82	81	81	81	81	80	80	80	80	80	80	80
Total Net Resources		**2170**	**2258**	**2255**	**2254**	**2254**	**2253**	**2253**	**2253**	**2253**	**2252**	**2252**	**2252**	**2252**	**2252**	**2252**	**2252**
System Demand																	
	Native System Demand	1826	1854	1894	1928	1959	1984	2017	2045	2073	2096	2131	2171	2216	2266	2321	2381
	CLMCOG	-14	-20	-27	-34	-41	-47	-52	-56	-59	-62	-65	-68	-71	-74	-77	-80
	Line Losses	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2
	Interruptible Sales	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62	-62
	Customer Owned Solar	-15	-19	-22	-25	-28	-31	-34	-37	-40	-43	-46	-49	-52	-55	-58	-61
Total System Demand		**1733**	**1751**	**1781**	**1805**	**1826**	**1842**	**1867**	**1888**	**1910**	**1927**	**1956**	**1990**	**2029**	**2073**	**2122**	**2176**
Margin Over Total Demand		437	507	474	449	428	411	386	365	343	325	296	262	223	179	130	76
Planning Reserve 13%		225	228	232	235	237	239	243	245	248	251	254	259	264	269	276	283
Margin Over Reserve		**212**	**279**	**242**	**214**	**191**	**172**	**143**	**120**	**95**	**74**	**42**	**3**	**-41**	**-90**	**-146**	**-207**
% Excess capacity		20.14%	22.45%	21.02%	19.92%	18.99%	18.24%	17.13%	16.20%	15.22%	14.43%	13.14%	11.63%	9.90%	7.95%	5.77%	3.37%