El Paso Electric

August 28, 2017

Integrated Resource Plan
Public Advisory Group: Public Input and Requests
Meeting Date: August 8, 2017

PAG Q1:
How does the information on pg 74 relate to the Loads & Resources table?

EPE Response:
This question will be addressed in the September 7th meeting when walking through the L&R table.

PAG Q2:
How specifically are the Out of Model Adjustments valued?

EPE Response:
EPE makes out of model adjustments in the load forecast for known changes in customer consumption that are not captured in the historical trend. These changes can affect both energy and demand forecasts. For example, if EPE knows that a city/county is replacing a large amount of streetlight bulbs with LED's, EPE can make an out of model adjustment to account for the reduced future consumption. This is done by removing the current amount of related lighting load and replacing it with the new LED related load.

PAG Q3:
What is the difference between the NM Energy Forecast Model and the Texas Energy Forecast Model?

EPE Response:
EPE forecasts energy sales for each of its jurisdictions separately, based on jurisdiction specific data. EPE employs substantially the same method in both jurisdictions, with results reflecting difference in customer populations (proportions of residential and commercial customers) and usage characteristics (e.g., peak demand and use-per customer).

PAG Q4:
How do you determine the energy savings from Energy Efficiency initiatives? Specifically how is the information on pgs 44, 53, 56, and 59 determined?

EPE Response:
Electric utilities calculate Energy Efficiency savings based on several methods such as national standards; federal, state, and local electrical codes; statewide Technical Reference Manuals; and, in some cases, measurement and verification of the installed measures. El Paso Electric Company's ("EPE's) Energy Efficiency savings have been evaluated and verified by the

statewide Measurement and Verification Evaluators chosen by the respective Commissions since the 2008 program year in New Mexico and the 2012 program year in Texas. Prior to 2012 in Texas, the deemed or stipulated savings for Energy Efficiency measures were verified based on various deemed savings filings at the Public Utility Commission of Texas that evaluated these measures.

Anticipated Energy Efficiency coincidental peak savings are calculated based on the current year’s demand goals in each jurisdiction with adjustments to those goals for expected realization rates and a reduction in savings for measures that do not coincide with EPE’s system peak. For future years’ savings, it is assumed that there are no statutory reduction in goals and that the existing programs remain in effect for all forecasted years.

PAG Q5:
How will energy efficiency possibilities be incorporated into the development of resource portfolios?

EPE Response:
Any demand side options will be input into the capacity expansion model as options for reducing peak load at appropriate costs. Demand side options will be modeled at capacity values consistent with reasonable expectations for adoption by customers.

PAG Q6:
You characterized several of the EPE owned renewable installations as “demonstration” projects. What conclusions have you drawn from the experience with these demonstration projects?

EPE Response:
The small renewable demonstration (pilot) projects implemented by EPE from 2009 through 2013 have provided EPE with valuable experience in deploying and operating different solar technologies on EPE’s electric grid. Some of the findings that we have experienced from these pilot projects include: EPE’s service territory is one of the best areas for solar production resulting in higher solar energy output than many other U.S. regional areas; single axis tracking systems yield a higher operating efficiency than fixed systems; concentrated photovoltaic systems (CPV) with dual axis tracking systems require more maintenance compared to other solar technologies; monitoring systems are important in early detection and troubleshooting of component failures; and, solar facilities are subject to high output variability swings during the day as a result of cloud cover and weather conditions.

PAG Q7:
What is the source of the forecasts referenced on pgs 22 & 23?

EPE Response:
The source of the forecasts referenced on page 22 and 23 is the solar developer/owner of the solar facility tied to each solar Purchased Power Agreement (PPA). There is a requirement in our PPAs for the developer/owner to furnish an updated forecast each year. The source of actual data referenced on page 22 and 23 is data gathered from the revenue meter which is located at each of the solar sites.

PAG Q8:
What conclusions do you draw from your experience from renewable demonstration projects?

EPE Response:
Please see response to Question 6.

PAG Q9:
Please clarify how the renewable Energy resources described in the presentation are represented in the Loads & Resources Table.

EPE Response:
This information will be covered in the September 7th meeting when walking through the L&R table.

PAG Q10:
Please provide TOU cost to add customers with existing (Itron) meters to add 100, 1,000, 10,000, 400,000

EPE Response:
EPE estimates meter and installation costs to be approximately $210.25 for residential customers and $320.75 for commercial customers. Assuming no other costs and using EPE's existing customer proportions, adding Itron metering in the numbers referenced here would cost approximately:

Meters	Residential	Commercial	Total
100	$ 18,923	$ 3,208	$ 22,130
1,000	$ 189,225	$ 32,075	$ 221,300
10,000	$ 1,892,250	$ 320,750	$ 2,213,000
400,000	$ 75,690,000	$ 12,830,000	$ 88,520,000

It should be noted the costs presented above do not include the additional anticipated costs for meter data management and bill processing capabilities.

PAG Q11:
Same as [previous question] but to go to AMI metering

EPE Response:
EPE has not produced a current full cost study for an AMI project in order to evaluate the capital and O&M costs and associated benefits of full deployment. EPE is evaluating initiating a full AMI project within the next two years. Based on current cost estimates, metering and data collection infrastructure for full AMI implementation is estimated to cost $90 to $110 million. This estimate reflects very general assumptions regarding an AMI project and could change substantially as specific requirements and capabilities are developed for a proposed infrastructure deployment.

PAG Q12:
Please provide cost estimates (with variations for location) for total cost and cost for the substation exclusive of land (location costs) for the Talavera area substation

EPE Response:
EPE has not filed the Talavera 440, which will provide the requested information when filed with the NMPRC.

EPE made application with the Bureau of Land Management (BLM) to construct a new permanent substation on public land adjacent to EPE's existing transmission line and Talavera Temporary substation. The BLM has determined that preparation of an Environmental Assessment ("EA") is necessary under the National Environmental Policy Act. The proposed EA will analyze the potential effects from the construction, maintenance, and operation of the substation, distribution lines, and associated infrastructure. The most recent public comment period closed August 17, 2017.

https://www.blm.gov/press-release/public-input-sought-environmental-assessment-proposed-el-paso-electric-project

Once an EA has been drafted, an additional public comment will be initiated by the BLM

PAG Q13:
Please provide the 440 and other filings that have been made

EPE Response:
On the NMPRC website http://www.nmprc.state.nm.us/general-counsel/case-lookup.html you go to "Documents Search" and under the "Title" field type 440, under "Company Name" field type El Paso Electric.

PAG Q14:
Please provide the information on requirements to participate in the Load Management (from page 56) and the benefits for participating. Please provide analysis of interruptible sales being allowed for residential and small commercial & general; which are ^ 70% of coincident peak but not currently allowed those lower prices.

EPE Response:
The specifics for the Load Management program can be found in the link below. We have not performed any studies directly for this Load Management program to be applicable to Residential and Small Commercial.

https://www.epelectric.com/files/html/Energy_efficiency/Energy_Efficiency_Program_Manuals/2017_Program_Manuals/2017_Load_Management_Program_Manual_Final.pdf

PAG Q15:
From the presentation EPE-Owned Renewable Resource it appears that EPE is vested into solar; with that background it would be helpful if EPE would welcome private solar panel on home,

and not attempt to charge a tariff on these systems. Would EPE be willing to consider this point of view?

EPE Response:

EPE has not proposed a tariff on private solar systems. EPE's currently proposed rate changes in Texas and future changes in New Mexico are designed to recover the cost of providing utility services to customers with private solar distributed generation. While EPE supports customer choice in electing to invest in private solar, EPE's goal is to reduce or eliminate any subsidy of DG customers by non-DG customers.

Received by email:

Don Kurtz 8/9/17
PAG Q16:
Could EPE [provide] the System Peak, in whatever form it is used to calculate needed load capacity, from 1995 through the present, and projected through 2037?

EPE Response:

The total system demand utilized for planning are listed below.

Year	System Demand (MW)
1995	1049
1996	1061
1997	1050
1998	1057
1999	1122
2000	1148
2001	1186
2002	1209
2003	1216
2004	1240
2005	1296
2006	1321
2007	1386
2008	1448
2009	1536
2010	1518
2011	1603
2012	1659
2013	1695
2014	1744
2015	1769
2016	1768

2017	1792
2018	1889
2019	1906
2020	1922
2021	1945
2022	1968
2023	1991
2024	2010
2025	2041
2026	2066
2027	2093
2028	2118
2029	2154
2030	2187
2031	2220
2032	2247
2033	2289
2034	2325
2035	2363
2036	2394

Gary Kelley 8/13/17
PAG Q17:
At last week's meeting, one energy efficiency program used internet-connected thermostats for demand management. What are the criteria used to determine when a demand reduction "event" is called?

EPE Response:
The current criteria used in our Smart Thermostat Demand Response pilot project to determine when to call a demand response event includes periods of high demand for electricity and, under certain electric system operating conditions or as necessary for testing and verification of the program results.

PAG Q18:
Also, there was a brief discussion of DG installations not paying their fair share of grid maintenance expenses. Would you describe EPE's reasoning behind this statement?

EPE Response:
DG customers billed under Net Energy Metering ("NEM") are credited for energy produced and exported by their systems at the retail energy rate. All distribution-related costs, as well transmission and generation costs, are recovered through the retail energy charge for NEM customers. These costs are substantially fixed in nature and are not avoided when DG customers produce energy. The cost recovery impact of the NEM effect is most evident in spring months when DG systems produce the most energy. Under NEM, billed energy is greatly reduced (in about 30% of bill months billed energy is zero), which limits cost recovery from DG customers

for these fixed capacity costs. This effect is most pronounced for distribution costs, because DG customers utilize the distribution system constantly throughout the month (importing and exporting energy), but may pay nothing for that service under NEM. This is the basis for EPE's statement regarding DG customers "paying their fair share" of grid costs.