The Electric Company
El Paso Electric

January 9, 2018

Integrated Resource Plan
Public Advisory Group: Public Input and Requests
Meeting Date: November 16, 2017

Questions received in notecards during PAG meeting 11/16/17

PAG Q1:

Please, [provide] more information on the solar and battery storage option. Other electric companies have used this in a very successful manner to provide cost saving. And they have done it to meet peak demand. Will EPE please consider solar & battery. The technology is there. Thank you!

EPE Response:

EPE is including battery storage as a resource to complement solar. EPE's October 5, 2017 presentation included several slides explaining how battery storage can complement a solar facility's variable output.

PAG Q2:

Please explain (or hypothesize) why Strategist picks any gas generating resource when Lazard's says that wind and solar are the lowest cost (levelized) energy resources.

EPE Response:

LCOE is not an input in Strategist. Additionally, there are other factors such as the output limitations of solar and wind due to their intermittent characteristics. This is especially applicable to wind which only contributes approximately 22% to 30% of nameplate at peak load hour.

PAG Q3:

What did you use for the cost of capital in the Strategist runs?

EPE Response:

The WACC EPE plans to utilize is 7.747%.

PAG Q4:

Please include a representation of relative environmental impact for each of the portfolio outputs from the Strategist runs.

EPE Response:

EPE has not finalized its review of environmental impact for the portfolios.

PAG Q5:

What fuel costs were used in the Strategist runs?

EPE Response:

	$/MMBtu
2018	$ 2.68
2019	$ 2.53
2020	$ 2.55
2021	$ 2.62
2022	$ 2.70
2023	$ 2.77
2024	$ 2.85
2025	$ 2.94
2026	$ 3.05
2027	$ 3.13
2028	$ 3.19
2029	$ 3.24
2030	$ 3.30
2031	$ 3.36
2032	$ 3.42
2033	$ 3.48
2034	$ 3.54
2035	$ 3.61
2036	$ 3.67
2037	$ 3.74

PAG Q6:

Please clarify the resource facility life that was used as the assumptions in the Strategist runs.

EPE Response:

Combined Cycle – 45 years

Combustion Turbine – 40 years

Reciprocating Engine – 40 years

Solar – 25 years

Wind – 25 years

DR – 25 years

Biomass – 25 years

Geothermal – 25 years

PAG Q7:

Please clarify how Strategist creates the net present value for a resource whose life extends beyond the planning period.

EPE Response:

Strategist analyzes resource portfolio additions with the concept of economic carrying costs which allows it to consider impacts beyond the 20 year window.

PAG Q8:

Let's do storage analysis outside of Strategist if the modeling through strategist cannot be designed to participants' satisfaction.

EPE Response:

All resources will be analyzed in a consistent manner within Strategist. While it may be necessary to perform some precursory analysis for certain resources outside of Strategist, all resources will ultimately be analyzed within Strategist.

PAG Q9:

Please provide a line item breakdown of fixed and variable O&M costs by generation technology?

EPE Response:

The LAZARD report does not provide a line item breakdown between fixed and variable O&M. However, the norm is that variable O&M is utilized for items such as consumables that are dependent on operation of the units/resources (e.g. oil, water treatment, etc…). Note, fuel is treated as its own category and not included in variable O&M. Fixed O&M typically carries all other O&M expenses such as personnel, routine maintenance and items that are required regardless of unit output.

PAQ Q10:

EPE should review what Xcel and SPS are doing with wind? How do they integrate so much wind energy? What makes EPE different?

EPE Response:

EPE is evaluating wind as part of its IRP.

PAG Q11:

Please run fuel costs as using past variability curves of natural gas.

EPE Response:

EPE plans to model low and high fuel costs for natural gas as a sensitivity analysis for the final runs and report.

PAG Q12:

Please model efficiency as a resource.

EPE Response:

EPE is planning to include EE resources in the IRP modeling.

PAG Q13:

Please analyze the cost of residential and commercial stand by generators at $200/kW as part of demand response such as 10 kW for $2000 installed. Please allow 40,000 units (~10% of residential) x 10kW which is 400 MW (up to 40,000)

EPE Response:

It is not clear from this question if the request is that EPE invest in small generators at customer locations as a resource, or if that EPE pay small customers with their own generators as part of a demand response program. Assuming the latter, EPE is evaluating rate-based voluntary DR programs which would compensate small customers for capacity provided during called events. These capacity bidding programs could be technology neutral from EPE's perspective – how the participating customer achieved demand reductions would be up to them.

EPE would note that small customer-sited generators are impractical for DR purposes and more appropriate for emergency operations. Issues include environmental and noise concerns. Widespread use of small generators is not a feasible customer option.

PAG Q14:

Same as Q14 but with small commercial with the same $200/kW

EPE Response:

See response above.

PAQ Q15:

Is there any difficulty or prohibition from EPE providing a standby generation subsidy and including that in rate base. If included can it be depreciated (amortized) over 20 years or more?

EPE Response:

See response above. A rate-based capacity bidding type program is being evaluated, although "standby generation" is not a feasible customer option.

PAG Q16:

What is the T&D cost included in the capital cost for resource capital costs? Re page 29 of presentation

EPE Response:

It is assumed that only the direct interconnection facilities are included in the capital dollars. There are no additional T&D costs, such as system upgrades, included in the costs. T&D costs beyond the interconnection are typically not considered in the IRP.

PAG Q17:

Please include the assumed operating hours for each resource per year (page 29 of presentation)

EPE Response:

EPE did not impose run hour limitation for resources other than the projected available hourly profiles for solar, wind, storage and demand response.

PAG Q18:

What is the retirement schedule included for Rio Grande 6 and all other.

EPE Response:

Please see September 7 presentation, slide 40 and October 26 presentation, slide 12.

PAG Q19:

Please show the retirement assumptions on the runs.

EPE Response:

See response to PAG Q18.

PAG Q20:

Please explain demand response costing if residential and commercial customers are given the interruptible rate kW and Kwh prices and nothing is paid to customer for the equipment, should the DR cost be done as $0. Please make a run with this.

EPE Response:

Curtailable rate options typically reflect a measure of incremental capacity cost for a gas combustion turbine for on-peak operation. EPE's NMPRC approved rates currently reflect an incremental cost of $100 per kW-yr.

PAQ Q21:

Please model 600 MW DR at $0 cost.

EPE Response:

EPE plans to model DR at some measure of incremental capacity cost, though not in the 600 MW range. EPE is unaware of any DR programs procuring incremental capacity at $0 cost.

PAG Q22:

Do you agree that the recent NM Peak was shown to be 181,733 MW for 84,675 customers which is ~2.14 kW per customer? Please state if a separate class for customers with refrigerated air would be more fair? If there is another rate class will this lower the demand growth to near 0 if the cost allocation is changed so evaporative cooled customers get a lower rate (~30% lower) and refrigerated air customers higher rate (+30% higher)

EPE Response:

No, the quoted figures of 181,733 MW is not NM peak demand.
Separate rate classes based on cooling technology would not be appropriate, based on standard ratemaking, but rate differentiation achieves the same result. A higher tier differential in summer months, or on-peak charges under mandatory TOU rates would have the effect of shifting peak cost recovery to more energy intensive cooling customers.

Question submitted via email on 12/26/17

PAG Q23:

I have not seen any discussion of the possibility of an electromagnetic pulse (EMP) causing harm to the electric grid.

Is there a credible threat to the electric grid if an EMP were to occur?

If there is a real threat is there any reasonable way of protecting against it?

If there is a reasonable way to protect against EMP is there any money in your long term plan to implement this protection?

EPE Response:

There has been a lot of recent attention given to the concern of an EMP threat in the media and by various entities. The current understanding of an EMP is its effect of damaging electronic equipment. The impact to electronic equipment is not limited to the power utility industry. EPE is monitoring various efforts by Federal entities such as FERC and the DOE to understand the expected breadth of impact and potential mitigation options. It is expected that these Federal efforts may result in standards, requirements and/or recommendations for mitigation of EMP impacts. Addressing EMP threats is not directly within the IRP scope. Once mitigation steps are identified, it may directly impact the IRP if the recommendations include specific resource type requirements.

Questions submitted via email on 12/20/17

PAG Q24:

The assumptions for resource options presented on page 14 (labeled 29) of the 16 November presentation are based, I believe, on Lazard's Levelized Cost of Energy Version 10.0. Version 11.0 is now available and there are some differences from Version 10.0. Does EPE plan to update its assumptions for resources options based on Lazard's version 11.0 before running Strategist for the 2018 IRP?

EPE Response:

EPE will update the Strategist model to include the latest LAZARD version 11.0 in addition to consideration from the PAG to consider future price projections.

PAG Q25:

In the 2015 IRP, EPE assumed a zero cost of carbon for the base case expansion plan, and ran carbon tax price sensitivities at $8 (per ton of CO_2?) and $20. What cost of carbon does EPE plan to use in the 2018 IRP base case? Does EPE plan to run carbon tax price sensitivity runs for the 2018 IRP? If so, what prices of carbon will be used for lower and upper bounds?

EPE Response:

EPE will assume $0 per ton for the 2018 base case run. For carbon tax price sensitivities, EPE will utilize standardized costs of $8, $20 and $40 escalated at 2.5% per year from 2011 forward.

PAG Q26:

In the assumptions for resource options presented on page 14 (labeled 29) of the 16 November presentation, EPE included cost assumptions for Wind, for Demand Response, and (page 15) for Storage. None of these resources was chosen in any of the preliminary scenario runs and none of them appear in the Legend of the initial or modified scenarios.

Was wind included as a possible resource in these Strategist runs? Was demand response included? Was storage included?

EPE Response:

Yes, wind, demand response and storage were included in the Strategist run.

PAG Q27:

In the assumptions for resource options presented on page 14 (labeled 29) of the 16 November presentation, demand response has by far the lowest capital cost, and has no fixed or variable O&M yet was not chosen in any of the scenario outputs on pages 20 and 22 of the 16 November presentation. Please explain this. If demand response was an option available to Strategist in these runs, what other parameters (other than capital cost) were input that could explain the lowest cost option not being chosen in any scenario? Please be specific.

EPE Response:

While DR options may have relatively low capital cost/start-up cost, they offer limited contribution to peak load due to both adoption rates and customer behavior for continuous utilization.

PAG Q28:

The assumptions for resource options presented on page 14 (labeled 29) of the 16 November presentation are based on the costs of building, maintaining and operating these resources, while PPA prices, as I understand it, are usually in terms of dollars per unit of energy ($/MWh). Recent Solar and Wind PPA prices have been trending down. Does EPE's model for determining the most cost effective portfolio consider PPAs for renewable energy? How are they considered?

EPE Response:

PPA prices downward trend has been due to corresponding drops in capital prices. Modeling of resources as "building, maintaining and operating" also acknowledges these downward cost trends. This approach does allow for effectively identifying the most cost effective resource portfolio when selecting across multiple resource types. All resources will be analyzed in a consistent manner within Strategist.

PAG Q29:

Does EPE agree that, in addition to determining the most cost effective new resources, the IRP process should include consideration of measures to get the most cost effective use from existing resources?

The Strategist model does take into consideration the continued use of existing resources and how to most effectively utilize those resources in conjunction with identified resource additions.

PAG Q30:

Does EPE believe that improving the system load factor by employing measures to reduce the system peak load should be a major goal of any resource planning project that aims to identify the most cost effective portfolio of resources?

EPE Response:

DR measures intended to manage peak load are a component of the IRP modeling, with resource selection based on the same standard as with other resources – the most cost effective portfolio of resources. Rate-based pricing options which provide price signals to customers to encourage efficient use of resources can also contribute to peak load management and are included in the IRP analysis.