October 16, 2017

Integrated Resource Plan
Public Advisory Group: Public Input and Requests
Meeting Date: October 5, 2017

Email received on 9/25/17

PAG Q1:
The first 5 questions refer to pages 48-49 of the IRP PAG EPE presentation for meeting 5 – September 7, 2017. This was the Resource Planning and Capacity Expansion Modeling presentation by Omar Gallegos. The graph on page 48 (Peak day July 14, 2016) shows generation and purchased power exactly matching native system load. This seems to mean that some generation or purchased power, and all off system sales, are not shown. The graph on page 49 (Low load – March 2, 2016) shows generation exceeding native system load. This means there must have been off-system sales which are not shown, and any non-PPA purchased power is also not shown.

EPE Response:
For clarity of this response and the context of the discussion, EPE assumes the reference to non-PPA purchased power to be market purchase power not part of a long-term purchase power agreement. The graphs on page 48 and 49 were provided as an illustration of a dispatch for a summer day and low load month. The key characteristics to take away are:

- Summer:
  - The summer load curve with peak hour being hour ending 16.
  - Contribution of solar during the day, including substantive contribution to peak hour (on average).
  - Use of peaking generation for peak hours of the day.
  - General stack order of baseload, intermediate and peaking generation.
- Winter:
  - The low load month (referred to as shoulder months – transition between summer and winter season) results in a low load profile throughout the day as there is minimal cooling or heating load.
  - Results in a relatively flat load profile through the day with a slight peak in the early evening.
  - Reduced number of generators online.

The values are instantaneous and are not integrated hourly values. There were no non-PPA purchased power transactions on March 2, 2016. It is correct that on March 2, 2016 there were off-system sales that occurred throughout the day. In the illustration, off-system sales occurred when the generation resources (including PPA resources) exceeded native load.

It should be noted that EPE also engages in paired transactions, where an equal amount of power may be purchased and sold resulting in a net-zero MW impact. Any sales paired with an equal purchase are not tallied as off-system sales since there is a no impact with respect to serving load.

PAG Q2:

Does the height of each colored section of the bar for each hour on both graphs represent the output power level for that generator during that hour?

EPE Response:
Yes, the height of each colored section of the bar represents the output of each generator at the beginning of the hour.

PAG Q3:
Have the output levels of generation, as shown by colored bar sections on the page 48 graph, been reduced below the actual output in order to match the native system load line?

EPE Response:
The output levels of the generators were not reduced. The purchased power amount was adjusted for the illustrative graph. The non-PPA purchased power on page 48 was adjusted to match load to resource output. Since load is varying minute to minute and resources are reacting in order to balance, the "non-PPA purchases" was adjusted on page 48 for the July scenario.

PAG Q4:
Why is some, but not all, non-PPA purchased power shown on page 48 while no non-PPA purchased power is shown on page 49?

EPE Response:
As noted in response to PAG Q2 above, on page 48 the non-PPA purchased power was adjusted to balance with load. On March 2, 2016 (page 49), there were no non-PPA purchases.

PAG Q5:
Please help me understand these graphs by explaining what criteria were used to determine what level and type of resources (generation, PPA power, and purchased power) is shown on each graph.

EPE Response:
The generation output reflects actual generation dispatch at the beginning of the hour. The PPA power shown was the cumulative output for solar resources registered at the beginning of the hour. Purchased power on the graphs is shown as explained on PAG Q2 and Q3 above.

PAG Q6:
Mr. Gallegos stated that it was his understanding that it is not the norm for EPE to sell power off-system at times of peak load. I understand that Rio Grande Electric Cooperative is considered part of native system load, Freeport-McMoRan sales are part of an equal exchange, and Southwest Reserve Sharing Group sales are generally small and mandated by a sharing agreement. Is Mr. Gallegos correct that EPE does not otherwise generally make off-system sales at peak times?

EPE Response:
It is correct that EPE does not normally make stand-alone off-system sales during peak hours at times when EPE is approaching annual peak load levels. EPE may enter into equal exchange or paired transactions as described above during peak hours (resulting in net-zero MW impacts).

PAG Q7:
The next question concerns distributed (customer sited) solar generation. In a meeting 5 presentation (page 42) EPE indicated that EPE Resource Planning has considered adjusting the output at peak for

distributed solar generation, to 45% of nameplate value. At the 22 September meeting a range from the high 30s to the high 40s was mentioned. Could EPE please explain the process by which they will determine the appropriate value to use in L&R documents for distributed solar generation output at peak?

EPE Response:
EPE has installed interval meters on a statistical sample size of DG customers. For purposes of adjusting nameplate capacity to estimate system output in peak hours, EPE plans to utilize the ratio of average output of DG solar installations versus their registered capacity for peak hour during the peak months based on sample meter data.

Email received on 10/5/17

PAQ Q8:
EPE allows for 3 separate sizes of solar capacity additions in its modeling (25, 75, 100 MW). Has EPE considered assigning individual CAPEX costs for each size, given that PV system costs ($/kw) vary wildly by scale? I am happy to provide some examples of the $/kw delta between 25, 75, and 100 MW sized systems.

EPE Response:
EPE recognizes there are some economies of scale based on the size of facilities. We see they may be more pronounced in the lower end (for example comparing a 1 MW facility to a 25 MW facility), but would expect the economies of scale to diminish as you are comparing larger sizes. EPE is open to considering cost information that is publicly available either from a source such as LAZARD, EIA or other comparable sources or from recently publicly disclosed facilities in regulatory filings.

Email received on 10/6/17

I was in the process of asking questions on the assumptions for resource options (page 48-49 of the 5 Oct presentation) when we moved on due to time constraints. So I am asking the remainder of my questions here.

Solar
PAG Q9:
You have chosen values from Lazard p18 "Key Assumptions" for a single-axis tracking system which is listed as producing the most energy (approx 30-32%). Have you, or would you, consider a fixed tilt design, aimed to produce maximum output at 3-4PM in June-July? This design would cost less to build, produce less total output, but higher output aligning with peak system demand. If the fact that power at peak is worth more than power off peak is taken into account, this design might prove to have a greater overall value.

EPE Response:
Single-axis tracking systems typically have an optimal orientation at peak summer hours given the trajectory of the sun during the summer months being higher in the sky (versus lower or more southerly as in the winter) and they normally track east to west while at a 0deg tilt angle. We would not expect a significant difference in output during the peak summer hours between an optimized fixed-tilt and single axis system. Additionally, the primary characteristic to resolve is the variability of output which is dependent on cloud cover.

The industry has gravitated to single-axis tracking as an optimal utility scale facility versus fixed-tilted or dual-axis tracking.

Wind
PAG Q10:
Dan Holguin explained that he used the high end of capital cost ($1,700/kW) because on Lazard's key assumptions page 19 it corresponded to a 38% capacity factor (right wind column) which he said is in line with what has been reported by NREL for our area. But he used $35/kW-yr fixed O&M from the left column. Was this an error? If not, why was $40 (from the right column) not used?

EPE Response:
The correct Fixed O&M costs for Wind based on the Lazard's assumptions is $40/kW-yr. EPE will provide an updated table that shows this value.

Gas Fired CT
PAG Q11:
The capital cost ($1,000) and Heat Rate (9,000) appear to come from the 103MW column (right column) of the "Gas Peaking" information on p20 of Lazard, but the fixed and variable O&M ($20 and $15) appear to come from the adjacent Reciprocating Engine data. Was this an error? If not, why were the Gas Peaking right column values of $25 and $7.50 not used?

EPE Response:
The correct Fixed and Variable O&M costs for a Gas Fired CT based on the Lazard's assumptions is $25.00/kW-yr and $7.50/MWh, respectively. EPE will provide an updated table that shows this value.

PAQ Q12:
I would note that this Lazard table shows that a gas fired CT with 10% capacity factor has a unsubsidized levelized cost of $217/MWh; the highest of any resource shown in your P48 table.

EPE Response:
Based on Lazard's assumed capacity factor of 10% the resulting levelized cost is $217/MWh. If a gas fired CT were to be selected by the model as part of this IRP process, EPE would expect a much higher utilization and capacity factor which would bring down the levelized cost of this resource. This higher capacity factor is consistent with EPE's experience with the combustion turbines most recently installed at Montana Power Station.

Gas Fired CT vs Gas Reciprocating Engine
PAG Q13:
In considering CTs vs Recips, do your inputs to Strategist, or to the larger resource choice process, include information about the differences in part load fuel efficiency and emissions, loss of output due to elevation and temperature, lead time for installation, reliability difference due to more units of smaller size vs less units of larger size?

EPE Response:
The Strategist inputs will include:

- Heat rates for local elevation on per unit type basis. Differences in heat rates between the different types will be input accordingly.
- Availability factors will also be estimated by type.

Capacity Assumptions (page 50)
PAG Q14:
An advantage to both EPE owned solar and EPE owned reciprocating engines is that they are very modular; they can be purchased in a wide range of output values. Would it not be wise to include solar capacities down to 5 or 10 MW and recips down to 2 or 3 MW - certainly some increment below 50MW? Solar can

be built in any size, taking into account size (acres) and location of available land and possible economies of scale. For recips you might choose one or more locations that minimize transmission and distribution costs and losses, build a facility (building) to accommodate multiple recips, and add additional recip units over time as needed to avoid carrying costs of unneeded capacity.

EPE Response:
From an IRP planning perspective to meet load requirements, we have chosen to start with larger increments which present the most cost effective economies of scale. In this fashion Strategist will select the most effective portfolio. We can do subsequent analysis of solar and/or reciprocating engines if Strategist picks them in the initial runs (with the higher increments, which have the cost benefits due to economies of scale). If selected, various deployment strategies can be further discussed.

Emails received on 9/14/17 and 10/9/17

PAG Q15:
Has EPE evaluated the costs and benefits of joining the Western EIM?

a. What were the company's findings?

EPE Response:
EPE has not performed studies related to joining the Western EIM.

PAG Q16:
Does EPE have transmission rights that connect the company's transmission to:

a. Current EIM participants in the EIM (e.g., APS, CAISO, NV Energy)?
b. Companies scheduled to join the EIM (e.g., SPR, LADWP)?

EPE Response:

a. Yes, EPE has transmission rights at the Palo Verde switchyard, and has transmission access to the Four Corners switchyard.
b. Yes, EPE has transmission rights at Palo Verde switchyard, and has transmission rights at Coronado and Springerville.

PAG Q17:
How large are EPE's transfer rights and what restrictions are placed on the exercise of such rights (e.g., firm rights, non-firm rights, single directions rights)?

EPE Response:
EPE's transfer rights are:

a. Palo Verde – Firm rights, limited to EPE's Palo Verde generation amount less 3rd party obligations.
b. Four Corners –
    i. EPE has 124 MW firm point to point transmission from Four Corners to West Mesa.
    ii. EPE has up to 150 MW of transmission rights over multiple transmission paths, which can include rights to Four Corners. These rights are cumulative, and therefore limited by EPE's use of the 150 MW on other transmission paths, and its need to meet native load requirements.
c. Coronado – See Four Corners response 3.b.2.
d. EPE's system interfaces with SRP at Springerville.

PAG Q18:
Could EPE bid part of its share of the Palo Verde Nuclear Power Plant into the EIM and use freed-up transmission from Palo Verde to EPE to make additional sales/purchases in the EIM?

EPE Response:
EPE has not explored the mechanics of utilizing Palo Verde, which is a baseload unit, into the EIM which requires responsiveness to energy imbalances.

PAG Q19:
How would PNM or TEP joining the EIM increase EPE's connectivity to EIM participants?

EPE Response:
EPE has direct tie-lines to TEP and PNM.

PAG Q20:
Can you clarify what is meant by "monitoring the development of the EIM"?

EPE Response:
EPE is aware of what entities have announced joining the EIM. Additionally, EPE has reviewed the APS filing summarizing its analysis on costs for implementing required software and joining the EIM. EPE is also aware of the public announcements by the Mountain West Transmission Group's plans to join the SPP.

PAG Q21:
As noted by EPE during the October 5 meeting, spreading out renewable resources can help to smooth variability; given that fact, why is EPE only monitoring the development of the EIM?

EPE Response:
While the EIM is designed to address the energy imbalance created in part by intermittent generation, EIM participants are still required to secure adequate resources for serving their load reliably.

<u>Questions received in notecards during PAG meeting</u>

PAG Q22:
I like the idea load management and load shifting, and its potential to reduce peak demand.

a. When will this reduction be modeled in the 20 year L&R table?
b. Will this modeling be accomplished in time to impact the decision whether or not a new gas-fired power plant is needed to meet peak demand?

EPE Response:
It is assumed that the question is in reference to the rate discussion and impacts to customer choice to load shift. The time table that is shown is a ten year horizon and is not an immediate impact to load profiles. The IRP analysis will include a base case run with the provided demand forecast (20-year L&R), as well as two sensitivity scenarios with high load and low load scenarios. The expectation is that any impacts of load shifting due to rate or rate structure changes will fall within the base case and the low load sensitivity run.

PAG Q23:
What is the cost allocation between the new transmission line from Rio Grande to Substation Re. August 2017 440 filing?

EPE Response:
Following completion of the Rio Grande substation to Sunset substation transmission line upgrade, the cost of the project will be allocated between jurisdictions and customer classes in a rate proceeding. EPE historically has allocated transmission based on jurisdictional and class contribution to the summer monthly coincident peak demand (4 CP).

PAG Q24:
Please define a PTR "resource" that would move demand off peak and contribute to "avoiding the need for new capacity" (per the IRP rule). Please format the resource using the Resource Option Template.

EPE Response:
Peak Time Rebate programs are more appropriately characterized as dynamic pricing than demand response, and incentivize reduction in customer usage during peak time periods. The net effect of customer response, whether load is shifted or simply reduced, is a function of how an individual customer responds to a PTR event. The extent to which this rate design "might assist in meeting, delaying or avoiding the need for new capacity" is likewise a function of how customers respond. On an event basis, PTR can assist in meeting peak demand with available resources by reducing concurrent customer peak demand. In the longer term, the extent to which future capacity requirements are impacted (delayed, avoided, etc.) will be a function of whether or not customers make permanent changes in their usage timing and requirements. In those instances, the effectiveness of PTR as a resource for is reduced and the near term benefit is translated into a long term benefit.

EPE plans to model rate-based pricing such as TOU and dynamic options as a variable in the load forecast used in modeling, not as a capacity resource.

PAG Q25:
How much carbon dioxide is EPE producing per year in billions of pounds?

EPE Response:
In 2016 EPE's total Carbon Dioxide equivalent emissions were 4.54 billion pounds. In 2015 total CO_2e emissions were 5.55 billion pounds and in 2014 total CO_2e emissions were 5.40 billion pounds.

PAG Q26:
Please portray all of the resources that EPE is proposing to model using the template. This will satisfy the requirement that resources be evaluated on a comparable basis.

EPE Response:
EPE has provided inputs for the resources it plans to model in the October 5, 2017 presentation (pages 47 to 52). Additionally, sample templates were provided and discussed. The templates were provided in response to PAG feedback that there was uncertainty on how to submit data. The participants may use the templates to:

- Submit input recommendations different to those listed in pages 47 through 52.
- Submit resource options different to those listed on pages 47 through 52.

The templates will serve as a starting point for discussion on the options/input being proposed. The fields in the template are open text and you may add narrative explanations as needed to fully describe your proposals/input. If we have questions upon receipt of the templates we will respond with questions and/or discuss in the subsequent meeting.

PAG Q27:
Please complete template for each of the resources that were proposed in response to EPE's all source RFP.

EPE Response:
The all-source RFP is still in process and is a competitive RFP. RFP respondents have submitted their bids as confidential and they cannot be disclosed during the RFP process. Disclosing the bids during the process may negatively impact bidders and jeopardize the integrity of a competitive bid process. Additionally, this could potentially prevent EPE from obtaining the best and final offers from bidders, which would in turn be detrimental to ratepayers.

Email received on 10/9/17

PAG Q28:
Please confirm that we are in agreement that "equivalent" as used in the IRP rule will be defined as +/- 3% of the net present value of the Revenue Requirement. If we are not in agreement, please propose an alternative definition and the related justification.

EPE Response:
EPE does not agree with this proposal. It is best to discuss this aspect of the Rule once the output data from Strategist runs is available, with the inclusion of the sensitivity runs and/or varying portfolio scenarios. At that time, discussion regarding equivalent resources as defined in the Rule can be had based on portfolios and costs.

It is worthwhile to quantify that +/- 3% of the 2015 IRP recommended portfolio's NPV would equate to potentially $133.9 million for the 20 year planning horizon.

It is also important to clarify the Rule states "For resources whose costs and service quality are equivalent…" (Emphasis added).

PAG Q29:
Please confirm that we will use 3 categories for the environmental impact of resources. The discussion seemed to result in agreement on the terms "least", "mid", and "most" environmental impact with no disagreement as to the characterization provided in the presentation material. If you cannot confirm this premise, please propose an alternative and the related justification.

EPE Response:
Initial thoughts are that an approach of this type may be the most appropriate. We can jointly discuss further as the process and the portfolio review progresses.

PAG Q30:
Please confirm that the values I used for Demand Forecast Assumptions detailed on pg 21 of the PAG presentation made on September 22, 2017 are correct and will be used in line 4.1 of the Loads & Resources Table. Alternatively, please clearly define and explain the values EPE believes are correct for line 4.1, Native System Demand.

EPE Response:
EPE will not utilize the demand numbers presented in the September 22, 2017 PAG meeting. EPE has adjusted the 20-year L&R table presented on September 7, 2017 to incorporate the 45% solar DG

contribution to peak hour during summer peak load season. EPE will utilize the numbers on the revised 20-year L&R table that will be distributed to PAG. The demand numbers that EPE plans to utilize are based on the econometric load forecast which is weather normalized as described in the August 8, 2017 meeting.

PAG Q31:
Please revise your assumptions around the growth in Distributed Generation. The L&R Table that EPE has provided to date, assumes a constant 3 MW/yr growth in DG over the planning period. Historical data shows that DG growth has been exponential, not constant at 3 MW/yr. Please provide a more appropriate forecast.

EPE Response:
EPE has not experienced exponential growth in DG systems over the period for which EPE has data (beginning in 2008). EPE utilizes the most recent two-year average increase in DG systems for forecast purposes, which captures near-term changes in system installations. The 3MW (2.5 MW) incremental annual DG capacity value is the annual amount of additional DG capacity that EPE expects at the hour of the system peak. The 3MW value is 45% of the name plate incremental annual DG capacity that EPE forecasts. EPE estimates annual DG capacity growth of approximately 5.62MW per year and believes the 5.62MW name plate DG capacity growth is reasonable and that a downward adjustment must be made to that name plate value when analyzing its impact to the system peak. Please note that EPE's DG forecasts are reevaluated and updated annually to try and account for changing trends.

EPE intends to discuss the issue of the long-term DG forecast more fully in response to the PAG presentation from the September 22 meeting, where the alternative DG forecast was proposed.

PAG Q32:
Please revise your assumptions in the L&R Table regarding the growth in Energy Efficiency to match other internal EPE documents.

EPE Response:
The L&R uses newer Energy Efficiency numbers than some T&D planning reports. EPE intends that the EE forecast embedded in the L&R table used for IRP purposes reflect the most current historical data on programs by jurisdiction.

PAG Q33:
Please explain how Energy Storage will be incorporated into this IRP process and the L&R Table per the new requirements in the IRP rule.

EPE Response:
Presently, EPE does not have any storage resources in its portfolio. If the current IRP process results in selecting storage, the storage resource would be identified in the L&R as a resource and denote its capacity in the appropriate year of deployment. EPE will model battery storage as a resource option in this IRP. The October 5th, 2017 meeting included the cost for battery storage and an explanation of how storage could be used in a resource portfolio.

PAG Q34:
Please remove the constraints described in the slide on pg 50, Resource Capacity Assumptions. There is the potential that limiting the "Total Available to Add" of each kind of resource will have unintended and unrecognized consequences in the outcomes. Alternatively, provide for comparable capacity in each renewable resource as what is provided for fossil fuel resources.

EPE Response:
As denoted in the presentation, EPE will evaluate results to determine if Strategist exhausts any particular resource and at that point evaluate more resources of that type. In particular, EPE will evaluate if a particular resource type is selected in the early years. Keep in mind EPE will need to evaluate regulating reserve and the reserve margin dependent on the amount of intermittent generation that is selected in the initial Strategist run (topic presented in the October 5th, 2017 meeting).

It should be noted that EPE consciously provided a total amount of solar resources that would cover the projected resource deficiency through 2026. The L&R provided in the September 7, 2017 meeting denotes resource need of 416 MW. Given the capacities and quantities for solar, EPE is proposing starting with 475 MW of solar options for the model to consider. Additionally, there is 200 MW of wind, 20 MW of Biomass and 20 MW of Geothermal to be included in resource capacity assumptions.