Foundational Issues PNM 2023 IRP

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PNM's 2023 IRP must consider solar, wind, energy storage, and demand response + energy efficiency in a distinctly different manner than their 2020 IRP.

- PNM's assumption regarding the effective capacity[ii] of solar, wind, storage resulted in a 100 – 133% increase in capacity requirements over the twenty-year period (2021 3,000 MW to 2040 6,000 – 7,000 MW),[iii] when the 20-year forecast of demand increases only 20%.[iv]
  - PNM does not pair storage with solar as a firming resource to improve the effective capacity of solar.[v]
  - Wind, solar, and storage were otherwise conceptually siloed or isolated from one another, giving the impression that there are negative effects from solar.[vi]
  - PNM assumed that under its 20-year "Current Trends & Policy Future" wind, solar, and storage decrease over time.[vii]

- PNM considered negligible demand response and energy efficiency (DR + EE) and assumed that DR + EE decrease to zero by 2031 for DR, and 2038 for EE.[viii]

- PNM assumed that 606 MW of "hydrogen-ready" new-build gas combustion turbines were for reliability purposes and would rarely run. This equates to essentially a 30% planning reserve margin (PRM), (606 MW CTs / 2,363 MW peak load 2040).[ix]

- It is not possible to compare the costs of new gas generation to wind, solar, and energy storage because PNM does not present resource costs by levelized cost of energy (LCOE).[x]

- Even with these foundational issues that bias the analysis to favor gas CTs, the no-CT portfolio costs only $188M or 2.8% more, over 20-year period, net present value basis (NPV). Hydrogen-ready CTs: $6,841M NPV to No CTs: $7,029M NPV.
  - In modeling terms, this difference is di minimis.
  - Because the CT and no-CT portfolios likely over forecasted the amounts of new wind, solar and storage needed to replace coal and gas, and because neither portfolio utilizes DR+EE as a utility resource, a more integrated analysis should result in a much lower forecast of future revenue requirements in a no gas portfolio.

For PNM's 2023 IRP, these are the foundational issues across all scenarios, futures, and sensitivities that should be vetted prior to modeling.

The end game of the stakeholder process should be real options to pursue in the action plan period, particularly as it relates to storage and DR + EE.

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ii ELCC Effective Load Carrying Capacity is the preferred method of measuring the capacity contribution of non-firm resources. **Note:** The derivation of ELCCs is complex via generally opaque modeling. Understanding the logic and key assumptions and algorithms used to calculate ELCCs, whether PNM's 2020 ELCCs for standalone solar and wind are reasonable, and how higher diversity benefit values from say using storage to firm solar, can be achieved, is critical going forward.

iii PNM 2020 IRP, Figure 4.

iv PNM 2020 IRP, Table 22.

v While solar effective capacity does decline as penetration increases, storage can be paired with solar to "firm" its intermediacy and improve its effective capacity. In fact, PNM's filing for the replacement of San Juan resources includes four solar + storage projects totaling 650 MW of solar and 300 MW of storage. (See Table 2). However, the modeling of the solar + storage does not appear to pair storage as a firming resource. For instance, in 2022, solar nameplate to effective capacity is cut by 83%, and in 2040 cut for a total of 94%. C Mitchell, PNM Table 2 and Appendix K.

- Storage otherwise is not paired with solar in PNM's 2020 IRP, with solar ELCCs between 8-10%, and wind 22%, 2040. (See Table 3).
- PNM's EnCompass model apparently did not include the logic to capture the synergistic effects between resources explicitly. PNM 2020 IRP 5.4.1.
- In sum, PNM needs a new worldview of storage in PNM's 2023 IRP, one that considers how "energy storage is like a Swiss army knife, and it has many uses and applications." E3 Consulting ppt Overview of E3 Storage Capabilities", 2/26/2019 (Resolve et al model)

vi PNM 2020 IRP Figure 23.

vii PNM 2020 IRP Table 22.

viii PNM 2020 IRP Table 22.

DR is listed as the last resource and included in the sum of "total generation". DR should be first resource and netted out of gross peak in the net peak calculation. This would reduce the MWs for the planning reserve margin (PRM).

Per PNM's 2020 IRP, Appendix L-3, there are two DR programs, Power Saver and Peaker Saver. Per a newspaper ad last Summer 2022, PNM also ran a PNM "Flex Your Power" program - customer initiated to join, where PNM communicated when curtailments would be helpful.

An update on these and any additional DR activities and programs (existing and planned), should be provided, including: Dispatch history, days and time, duration correlated to peaks (how measured, derived); Location on distribution system; Number of participants and incentives paid.

Note: DR + EE are multi-attribute resources that can no longer be essentially ignored by PNM. A key focus of the stakeholder process should be on developing a much more robust approach to DR + EE that is implemented asap.

ix There are several other concerns regarding key assumptions re HRCTs that should be resolved, including: PNM maintains a large fleet of gas gen up to 2040 when "poof", it becomes hydrogen! (987 MW gas 2021 - 2027; 2031 - 2039 692 MW; then 2040 0 MW).

The use of CTs for supposedly planning reliability only also raises the questions regarding PNM's 18% PRM applied to peak demand. The 2017 IRP dropped RM to 13%; was 15%. PNM has increased to 18% given increasing solar and storage penetration. Questions: Where on the system does the peak occur and how determined, measured? Cause(s) of the peak identified by distribution station, circuit, line, feeder. How does an additional 350+MW added to total resources (assume 2000 MW peak * 18%) provide reliability to the most common service disruption: Distribution.

x See Lazard's Comparative LCOE data Comparison – Unsubsidized Analysis, p.2 shows that: Solar PV+Storage-Utility Scale: $46 – 102 LCOE. Gas Peaking $115 -221 LCOE.
https://www.lazard.com/research-insights/2023

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