PNM Responses to Comments from EFG, CCAE & SWEEP

Responses to the questions sent to PNM by Anna Sommer on behalf of EFG, CCAE and SWEEP follow.

STAKEHOLDER PROCESS

Stakeholder processes in support of an IRP are important, but also complex undertakings, and we appreciate that PNM is committed to a stakeholder process that is not superficial. Addressing multiple concerns and viewpoints while helping to unpack the variety of assumptions and inputs in an IRP is a challenge for any utility. EFG has been a part of many IRP stakeholder processes and has seen a wide variety of approaches, some that work and some that do not. Some of Indiana's IOUs use a process that we've seen work fairly well. Each meeting is scheduled ahead of time, as PNM is doing, but they also set the schedule so that stakeholders know which topics will be discussed as in this example from AES IN's 2022 IRP:

This figure shows the public stakeholder process leading up to a November filing deadline. The data that would be discussed at each meeting is released well before the meeting for two reasons. One is to give time for stakeholders to review it and draft up questions, the other is because there is also generally a "technical" meeting before the public meeting so that confidential information can be discussed.

Another important element of these meetings is that these utilities set aside some time at the beginning of every meeting to go over a list specific items of feedback they've gotten and how they will address that feedback. Prior to meeting 4, stakeholders who have signed
NDAs get the utility's model too, which we can load and look at it in its native format. There can be substantial differences between summary data of model inputs and the

manner in which they are modeled. Having the model itself also allows us to look at the simulation settings which can influence the optimization and helps create an understanding of how assumptions such as costs and build limits change through time. To the extent any errors are identified in this review that can be especially useful *before* the IRP modeling is finalized so that the post-IRP filings are not dealing with the implications of errors, but rather the merits of the preferred plan and the modeling supporting it. For all these reasons, we request access to the Company's Encompass and SERVM models.

Given our experience in PNM's stakeholder meetings so far, we strongly recommend that PNM adopt a process like this one. It will help all participants use their time wisely, e.g., they can opt in/out of meetings that are not relevant to their interests and it will help avoid the situation that routinely seems to come up in PNM's meetings to date, which is that there is not enough time to cover issues and clarify the information that is being presented.

> Response: Gridworks provided a meeting schedule with an outline of topics at workshop #2 and has updated these topics and dates with successive office hours and workshops. Given the dynamic nature of this process, Gridworks recommends flexibility in the scheduling/planning to accommodate new needs as they arise.
>
> In an early survey, stakeholders indicated a preference for workshop materials 3 days in advance. While we haven't met this goal, Gridworks has initiated several office hours after workshops to provide follow up time on presented material. Our goal in doing so is to give stakeholders time to digest and seek clarification on previous material before introducing new material at the next workshop.
>
> This need for technical workshops has not come up in our workshops. Stakeholders in this process have voiced objections to holding exclusive sessions. Non-technical stakeholders benefit from hearing technical discussions.
>
> Time will be dedicated at each meeting to respond to stakeholder feedback. The three office hours following workshop #3 and the first hour of workshop #4 were dedicated to this. Gridworks will encourage keeping this as a standing agenda item in future workshops.

LOAD FORECAST

At the February 11th meeting, we heard conflicting explanations for which new loads are included in PNM's load forecast. Initially, it seemed like only loads that meet an 80% probability (and are judged as such because they have made a downpayment) are included in the HEG forecast, but with further explanation it seemed that all loads deemed 80% probable were included in all three load forecasts and have met thresholds like having signed reimbursable agreements for interconnection costs. It would be especially helpful to see all load forecast workbooks. These include PNM's econometric variables and regression results and PNM's probabilistic model for large loads—to evaluate the documents related to that model that PNM is collecting for those large loads even if it's anonymized or names are redacted. We'd also like to know under which rate class these loads would take service, whether a large load tariff is being considered, if PNM is considering incorporating certain resource requirements into supply contracts, and what your line extension policy is, if any, that applies here.

> Response: The large loads in the IRP forecast are ones that signed a reimbursement agreement or are existing customers that are expanding operations. While there is some additional economic development as part of the HEG, it is not specific to large load customer requests. PNM included rate class models on Venue a couple of weeks ago in the Load Forecast Workpapers Folder. PNM is working on a proposed large load tariff to potentially include in its next rate case.

LARGE LOAD INTERCONNECTION

Given the unique characteristics of concentrated and synchronized power electronic loads[1], we are also interested in how PNM is studying these loads for interconnection. The results of interconnection studies can influence needs in the IRP such as the timing of new loads, e.g., if limited by the in-service dates of transmission projects, ramping needs modeled in the IRP, as well as the overall likelihood of interconnection. We'd like to request any documents related to your large load interconnection policy that include any standards[2] PNM applies in those studies and any operational limits PNM might impose in interconnection or service agreements with those customers, or whether PNM's interconnections provide for expansion for existing and future proposals. We're also interested in what PNM has determined so far with respect to transmission mitigations that might be needed to add these loads and the in-service dates for network upgrade projects.

> Response: Large load interconnection requests are evaluated using PNM's standard transmission interconnection study framework, which assesses thermal loading,

voltage performance, short circuit duty, stability, and protection impacts. Customers provide load ramp data, load factor, and power factor data to PNM that is utilized for these studies. These studies adhere to FERC and NERC requirements.

PNM is performing a cluster study on large loads that have signed study agreements. This study is not complete. The study will define the network upgrades and schedule that will be needed to reliably provide service to the large loads. Regarding the load model, we use a composite load model that includes motor and cooling load, electronic load, lighting and other loads.

Regarding generation dispatch, I am not sure if it is appropriate to include the assumptions we have made for the large load which is essentially the list that your team provided to use and we multiplied it by 2 I think.

MARKET POTENTIAL STUDY

As it relates to the market potential study (MPS), we would like to request the workbooks used to develop the energy efficiency (EE) and demand response (DR) bundles for modeling in EnCompass.

Response: All workbooks associated with the EE bundles as well as the potential DR programs that stem from the PNM Potential Study 2026-2045 were uploaded to the IRP Venue site on February 26, 2026.

For Demand Response:

1. **Program Bundles.** All cost effective, achievable resource potential for DR products modeled in an MPS should be present and reflected within the IRP. Since DR products effectively represent unique programs, each with unique levelized costs, one approach to modeling could involve running every program separately and individually. Recognizing this may be computationally challenging, DR program bundles can be constructed involving like groupings of DR programs. These groups could be based on several factors, including: sector or customer segment/class, tiers of resources by levelized cost threshold, or type of demand response (e.g., rate-based DR vs. control based vs. behavioral DR; firm vs. non-firm DR). The goal for bundling is to have enough distinct resources selectable within the IRP and to avoid over-bundling that may result in bundles that blend combinations of

resources with varying levels of cost effectiveness. The thrust here is that a variety of different end-uses are likely to be targeted through a comprehensive DR program, but there will be some threshold at which additional DR is not likely to be cost-effective.

Response: PNM is modeling every potential program for DR separately. PNM does not use a bundled approach for modeling DR potential programs. PNM's approach was discussed in the Workshop #3 meeting on February 11, 2026. All the potential programs are granted equal footing in the software database and are allowed to be selected independently or in combination with each other. This provides the maximum ability for new DR resources to be selected in PNM's modeling efforts.

2. **Savings.** Conversion of the savings from the MPS to the IRP should account for the peak marginal line losses rather than average losses. Losses are determined based on I^2R (the square of current times the resistance of the line) therefore demand response's ability to avoid losses increases as line loading increases, which are at their highest during peak periods. Demand response reduces consumption on the margin, so the peak marginal line loss rate should be used to convert savings from the meter to the generator for purposes of IRP modeling.

- Savings should be converted to the generator using peak-period marginal line losses as follows: generator savings = meter savings / (1 - line_loss_marginal). If the line loss study does not specify a marginal value at peak, it can be estimated using average line loss x 2.86 (extrapolated based on this RAP report).[3]
- A similar marginal peak line loss factor should be used for any economic screening of DR resources within the MPS, as applicable.

Response: In the years 2026-2029, no line loss calculation was applied. For the years 2030 and beyond, PNM's vendor for the potential study, ICF, used annual peak line losses to calculate savings. Although marginal annual peak line losses could be utilized, the savings achievable would be considered to have a minimal impact on cost effectiveness.

For Energy Efficiency:

1. **Time vintages.** Since the selection of EE within an IRP often informs the level of savings implemented in the plan, we recommend aligning the selection of savings with the next two DSM plan periods. To reduce the overall problem size, the remaining years can collapse into a third time vintage.

- Align the first vintage with the upcoming DSM plan period (e.g. 2026-2028)

- Align the second vintage with the following DSM plan period (e.g. 2029-2031)
- A third vintage should include all remaining years of the MPS

Response: IRP modeling is distinct from the Energy Efficiency & Load Management Triennial Plan performed by PNM's EE team which is designed to meet the EUEA requirements. For IRP modeling, the goal is to determine if additional EE bundles can be economically achieved beyond which to be proposed by the upcoming Energy Efficiency & Load Management Triennial Plan filing which covers 2027-2029 to meet the energy load requirements of the system. IRP modeling is not restricted to any such timeframes defined since the analysis only seeks to provide an indication or magnitude of the bundles at projected costs of energy efficiency programs that could be added to PNM's portfolio. Program specifics are not identified nor determined in an IRP analysis. Should EE bundles be selected and included in the most cost-effective portfolio, this would indicate that new energy efficiency programs that are like the bundles evaluated should be pursued in a future RP procurement/solicitation process where detailed program design would need to be identified.

2. **Program bundles.** Because multiple levels of savings should be tested and there can be wide differences in the costs of different measures, we recommend grouping programs into bundles that align with the implementation of these measures while still allowing some flexibility in choosing the level of savings offered. C&I measures tend to be among the most cost-effective and can be evaluated as one bundle. Income qualified residential measures do not have to pass cost
effectiveness screening, so they should be grouped separately and fixed into the plan. Residential behavior measures are uniquely short-lived and can be widely applied and should be bundled separately from other residential measures.

- All C&I
- Residential income-qualified
- Residential behavior
- Residential – low/medium cost
- Residential – high cost. If necessary or appropriate, split out the highest cost measures (in terms of $/lifetime kWh) and bundle separately, so that the remaining low/medium cost measures have an opportunity for economic selection. The highest cost bundle should not represent more than ~ 15% of the residential potential after removing IQ and behavior.

Response: PNM is flexible to consider this approach and would work with any stakeholder and our consultant (ICF) to determine the best approach to use. To determine specifics, please request a stakeholder scenario to begin the process.

3. **Scenarios.** An enhanced C&I RAP scenario consisting of increased incentives and therefore increased savings for measures that remain cost-effective can be created to maximize the level of cost-effective potential evaluated in the IRP. Each level of savings can be evaluated explicitly by forcing in the level of savings or simply making the bundles selectable.

○ Commercial: base RAP and enhanced RAP, separately with each being selectable ○ Residential: RAP, selectable (excluding income qualified, which is forced in) Response: See PNM's response to item #2.

4. After completing steps 1-3, there will be 18 bundles as follows: ○ C&I: 3 time vintages x 1 program bundles x 2 scenarios = 6

○ Res: 3 time vintages x 4 program bundles x 1 scenario = 12

Response: See PNM's response to item #2.

5. **Savings.** Conversion of the savings from the MPS to the IRP should account for the net to gross ratio and the marginal line losses rather than average losses. Losses are determined based on I^2R (the square of current times the resistance of the line) therefore energy efficiency's ability to avoid losses increases as line loading increases. Energy efficiency reduces consumption on the margin, so the marginal line loss rate should be used to convert savings from the meter to the generator for purposes of IRP modeling.

- Lifetime savings should include savings that persist beyond the IRP planning horizon
- Savings should be converted from gross to net using net-to-gross ratios specified in the MPS
- Savings should be converted to the generator using marginal line losses as follows: generator savings = meter savings / (1 - line_loss_marginal). If the line loss study

does not specify a marginal value, it can be estimated using average line loss x 1.4 (based on this RAP report).

Response: In the years 2026-2029, no line loss calculation was applied. For the years 2030 and beyond, PNM's vendor for the potential study, ICF, used annual peak line losses to calculate savings. Although marginal annual average line losses could be utilized, the increased savings achievable in 2026-2029 and presumably decreased savings achievable in the years 2030 and beyond would be considered to have a minimal impact on cost effectiveness.

Energy efficiency bundle savings are captured in the planning period along with the costs. This methodology puts energy efficiency bundle savings and costs on the same basis as other candidate resources. For this reason, lifetime savings beyond the planning period is not included in the IRP analysis.

6. **Levelized cost calculation**.

- The NPV of the lifetime savings should be calculated using a real discount rate. It

is important to use a real (not nominal) discount rate since energy savings do not experience economic inflation. The nominal discount rate should be converted to a real discount rate using the inflation rate assumed by the MPS.

- Future costs from the MPS should be converted to real/current dollars, removing the effect of inflation if applied in the MPS. This step is necessary since the efficiency cost NPV must also be calculated using a real discount rate. • MPS costs should net out avoided T&D benefits, since they aren't picked up in the IRP modeling.

- The NPV of EE costs should be calculated using the real discount

rate. - Levelized cost = NPV cost / NPV lifetime savings

Response: For the potential study, levelized cost is calculated by levelizing the upfront (and any ongoing) costs over the measure's life and dividing this levelized annual payment by the first-year energy savings. The levelization is performed using a real discount rate. For IRP modeling, PNM used annual costs and not levelized costs for any potential bundle. T&D deferral costs are accounted for within IRP modeling as a credit to potential program costs. All NPV costs in the software modeling are based on using a real discount rate.

Regarding the MPS itself, we have several questions and observations after having had a chance to review the document.:

1. Program Potential: ICF ties Program Potential to ramping program activity to meet the EUEA 5% savings requirement by 2030 (relative to 2025 sales). Is that ramp calibrated to PNM's historical program performance, or is it primarily a policy driven adoption path? If it's policy-driven, what assumptions drive the ramp (adoption, incentives/budgets, measure mix)?

Response: Program potential was informed by PNM historical program activity and data on maximum customer willingness to participate in energy efficiency programs. Using these assumptions, the estimated potential was sufficient to meet the EUEA requirements, so additional policy-driven adjustments were not required.

2. 2026–2030 subtraction: ICF indicates Program Potential is subtracted from Achievable Technical during 2026–2030. Please explain what the rationale for that is and how that is implemented in the IRP inputs (e.g., what is forced in vs what is selectable as incremental EE).

Response: During 2026–2030, Program Potential is subtracted from Achievable Technical Potential to avoid double counting energy efficiency that is already assumed to occur under statutory EE requirements. In the IRP, that portion of EE is forced in as a baseline load modifier, and the remaining incremental potential beyond those goals is not made selectable to keep IRP modeling consistent with PNM's EE team's triennial filing process.

3. Data appears to be missing from the MPS. The market profiles in Appendix A and the adoption curves in Appendix B are missing, can you please provide them?

Response: The supporting files for Appendix A and B have been added to the report.
https://www.pnm.com/documents/d/pnm.com/pnm-2025-potential-study-report-1-pdf

4. Can you post an updated version of the MPS with an update ToC to give the correct page numbers?

Response: PNM will post an updated version of the report with corrected page numbers. https://www.pnm.com/documents/d/pnm.com/pnm-2025-potential-study report-1-pdf

5. The MPS describes the levelized cost methodology for DR, but not EE, can that be added?

Response: The potential study report is not being updated at this time, however, a description of the levelized cost methodology is provided below.

For each measure, ICF estimates the per-unit annual electricity savings, per-unit costs, and effective useful life. For the levelized cost from a Utility Cost Test basis, only the assumed customer incentives and utility administrative costs are considered. To calculate the levelized cost, the cost is levelized over the measure life (using a real discount rate) and this flat annual value is divided by the annual energy savings (grossed up for line losses).

6. What incremental cost is assumed to be paid for each measure?

Response: ICF develops an estimate of the typical incremental cost for each

measure using technical reference manuals, market data, and other sources.

7. How were meter-level savings converted for IRP modeling? Were marginal or average line loss rates used? And were peak rates used for demand response?

Response: For both demand response and energy efficiency, in the years 2026-2029, no line loss calculation was applied. For the years 2030 and beyond, PNM's vendor for the potential study, ICF, used annual peak line losses to calculate savings. Although marginal annual peak line losses could be utilized, the changed savings would be considered to have a minimal impact on cost effectiveness.

8. Feasibility and timing: the slides note some rate-based options were screened out due to billing feasibility. How are near-term feasibility constraints reflected in the IRP base case(s), and what DR options are actually modeled/selectable?

Response: The IRP base case reflects no rate-based options. The DR potential options noted in the potential study are actually modeled/selectable. The DR potential options that were screened out due to billing feasibility were Critical Peak Pricing and Peak Time Rebate.

9. DR cost basis: what cost components are included for DR options (admin, incentives, enabling tech, etc.), and where is that documented?

Response: Cost includes administrative costs, development costs, incentive costs, equipment/installation costs, vendor costs, marketing costs, and O&M costs. These can be found in the Program Inputs workbook in the Cost Inputs tab as well as the PNM DR Viewer – Integrated 3.0 workbook across several tabs.

An 8% profit incentive adder was applied to all strictly defined demand response (DR) programs,. Please note that the electric vehicle time of use, time of day rate, and the electric vehicle direct charge management potential programs were not considered strictly defined demand response programs even though they were included in the demand response portion of the potential study. PNM has not

traditionally included profit incentives for these types of programs. In contrast, consider strictly defined demand response resources that PNM projects would be funded outside of the EUEA framework—such as grid-interactive water heater and battery energy storage direct load control potential programs. These resources were assumed to require a policy change to allow for the inclusion of a profit incentive in order to have a similar profit incentive treatment to demand response resources within the EUEA framework.

10. EE/DR interaction: how is double counting avoided between EE load reductions and DR capability (baseline assumptions / hierarchy)? How is the study accounting for positive or complimentary interactions between EE and DR, such as increased saturation of eligible equipment/devices, increased likelihood of adoption?

Response: The EE Achievable Potential forecast serves as the baseline for the DR analysis. This methodology is used both to reflect that energy efficiency programs may lead to increased saturation of DR-enabling equipment and that more efficient equipment may lead to lower DR program impacts.

11. Post economic screening, did the analysis revise potential estimates for any products that split the population (e.g., if EV TOU and EV DLC assumed separate portions of the market, and EV DLC was not selected for achievable potential, the population of customers likely to enroll in EV TOU should increase)?

Response: In the integrated case, a program hierarchy was applied to account for programs that draw from the same pool of eligible customers for a given end-use technology. This hierarchy ensures that once one program selects participants, the remaining programs draw from a reduced pool. Programs were ordered based on their

likelihood of adoption so that the most probable programs select customers first, and subsequent programs reflect the appropriately decremented pool. A stand-alone case was also simulated where each program acts in a vacuum of other programs (i.e. no competition for eligible customers). Because economic screening was not performed within the potential study, the type of reallocation suggested was not performed within the study.

12. Some decision making occurred regarding the ramp rate of program adoption, which is reasonable; however, rollout of products like TOU and BDR appear overly conservative, showing up in a meaningful way only beginning in 2035. The study is missing near term potential, particularly for BDR since this can be rolled out almost instantaneously.

Response: Although programs can be rolled out in a year or two, PNM's experience is that behavioral programs take some years to reach their full potential. We believe that this is due to customers taking some time to adjust to the new messaging, figure out what new behaviors work for them, and implement the new behaviors.

13. Can you provide us with detailed information about achievable potential by program, season, and year?

Response: This information is included in the PNM DR Viewer – Integrated 3.0 workbook in the "Program Potential" tab.

14. Res HVAC DLC (Power Savings) and Non-Res Voluntary Curtailment (Peak Saver), both existing programs, make up the bulk of DR potential across the horizon. TOU, EV TOU/Managed Charging, and Behavioral show up in later years. As noted above, we would expect TOU and behavioral to show up sooner, and would expect TOU may reflect a larger level of total potential. Both APS and SPR have robust TOU programs with 30%+ adoption – unless ICF made very conservative estimates on the TOU adoption rate or rate design (e.g., low peak to off peak ratio), we would expect this could be a more significant near-term lever for capacity savings.

Response: All non-existing programs are assumed to launch in 2030, followed by a five year ramp to reach steady-state participation. Given the inherent uncertainties in program design, regulatory approval, and implementation timelines, PNM intentionally selected conservative start years for these future programs to ensure the analysis reflects realistic planning and rollout expectations.

15. We request the cost-effectiveness analysis workbooks and results for all measures and the avoided costs used in that screening.

Response: Information on demand response measure costs is provided in in the PNM DR Viewer – Integrated 3.0 workbook which was uploaded to the 2026 IRP Facilitated Stakeholder Process. Avoided costs provided by PNM are included at the bottom of the UCT tab.

GOING-IN POSITION

During the February 11th meeting, PNM presented this chart showing its going-in resources by technology type.

Description	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Coal Resources (MW)	160	160	160	160	160	160	0	0	0	0
Total Nuclear Resources (MW)	282	282	282	282	282	282	282	282	282	282
Total Natural Gas Resources (MW)	966	966	977	1,314	1,314	1,354	1,354	1,354	1,354	1,354
Total Demand Response Programs (MW)	49	49	49	49	0	0	0	0	0	0
Total Renewable Resources (MW)	231	234	237	343	342	344	344	344	344	327
Total Storage Resources (MW)	854	991	1,294	1,494	1,494	1,621	1,621	1,621	1,621	1,621
Total Short-Term Firm Wholesale Purchases (MW)	50	150	100	0	0	0	0	0	0	0
Total Resources (MW)	2,592	2,832	3,099	3,642	3,593	3,761	3,601	3,601	3,601	3,584

It appears that PNM is assuming resources identified through procurement activities related to the 2023 IRP are going-in resources and will be fixed in its modeling. Based on the IM's report on the 2023 IRP, it appears that those resources consist of a mix of specific projects identified through PNM's RFP and generic gas units that PNM has added to its model. One of those resources is a 344 MW gas combustion turbine. However, that size doesn't appear to conform with the size of combustion turbines generally available on the market. F-class turbines are about 200 to 230 MW in size and H-class turbines are 290, 380, or 430+ MW in size depending on whether they are GE or Mitsubishi machines. How, if at all, would using a different sized machine based on a specific OEM proposal influence PNM's modeling in the 2026 IRP?

PNM also discussed the upcoming release of a dispatchable capacity RFP, will the responses to that RFP result in any changes to modeled resource costs?

Response: For gas turbines, OEM quoted sizes are based on a standard set of conditions (59 F and sea level). Output for any gas turbine is dependent on ambient air temperature and site elevation. Output will decline for any temperature or elevation above ISO (International Organization for Standardization) conditions termed a derate. For long-term planning assumptions, PNM uses derated values to accurately account for expected capacity. For modeling purposes and considering PNM's load size, PNM will select the smallest OEM sizes such aeroderivative and frame

7 classes based on GE technology which will be derated for typical site conditions in New Mexico during the peak period. Modeling larger sizes for any economies of scale is an activity of an RFP process.

FUTURE RESOURCES

During the February 11th meeting, PNM stated that it will generally assume that resources cannot be added before 2033. Is this a product of an implementation limit that PNM sees for new resources or a simplification for the modeling due to a lack of capacity need before 2035 in several scenarios? Finally, for the HEG runs in which the first year available date is generally relaxed to 2029, what leads PNM to the conclusion that it can bring a SCGT online by that date? Does PNM have an existing manufacturing reservation agreement with any OEM? Is PNM entertaining the idea of purchasing gray market turbines?

Response:

1st Question:

For technologies that require time to reach commercial development, the first available year ties to its technological readiness as well as the expected timeframe to obtain regulatory approval and interconnection/transmission availability. For all other technologies, the first available years are dependent upon the future being evaluated. For CTP & LEG futures, the years where PNM is seeking potential resource procurements begin in 2033, since years 2026 through 2032 have already been defined. For the HEG future, some resource technology first year availability have been moved up in time to allow candidate resources to be added to meet the higher load requirements before 2033. There are no restrictions in the model impeding new resource selection except the first available date. The only exceptions to this are for generic wind resources (can add up to 1,500 MW of new wind) and potentially solar (PNM is testing whether or limit only the annual maximum to 300 per year, which reflects the largest historical sizes PNM as procured in any given year.

2nd Question

Based on the timeline PNM provided in Workshop #2, PNM believes that if all approvals can be obtained, gas technologies which are among the most mature of all candidate resources can be brought online by 2029.

3rd Question

No, not at this time. Manufacturing reservations are considered an RFP

procurement activity and not part of the integrated resource planning process nor is it factored in the

modeling. The IRP determines direction and magnitude of resource selection. Specifics are determined through market solicitations.

4th Question.

Purchasing of any equipment for the purpose of procuring resources is not an activity of the IRP process, nor is it factored in any IRP modeling. However, currently PNM is analyzing gray market turbines.

Will PNM model Renewable Energy Act Renewable Portfolios Standards (RPS) to 2045 and take into account stranded asset costs for new proposed gas turbine plants being proposed? Will costs of conversion to hydrogen be considered in order to meet the 2045 RPS requirements?

Response: The IRP modeling will take into account the Renewable Energy Act RPS. Should the modeling select any new gas resource turbines, the cost to convert to burn hydrogen gas is included in the model. This data can be found on 2026 IRP Facilitated Stakeholder Process Venue site.

CONCLUSION

EFG, CCAE, and SWEEP value this opportunity to comment upon PNM's IRP. We also hope the feedback is responded and that all data requested is supplied to us and that the questions we posed elicit answers. We remain open to providing support and feedback. To summarize, we ask PNM for the following:

1. Publish a detailed meeting schedule with clear topic

sequencing. 2. Release data well in advance of meetings.

3. Hold technical (confidential) sessions prior to public meetings.

4. Dedicate time at each meeting to respond to stakeholder feedback.

5. Provide stakeholders (under NDA) access to the actual models (EnCompass

and SERVM), not just summaries, to allow review of modeling assumptions and simulation settings before finalizing the inputs.

6. Provide the load forecast workbooks (econometric models, regression results, probabilistic model for large loads).

7. Provide documentation supporting large-load probability model inputs (even if anonymized).

8. Provide clarification on rate classes for large loads, possible large-load tariffs, supply contract requirements, and line extension policies.

9. Articulate the interconnection standards and operational limits for large load customers.

10. Provide any studies conducted for those customers such as system impact or feasibility studies.

11. Describe the manner in which the large load interconnection study results influence IRP modeling (timing, ramping, feasibility).

12. Provide the MPS workbooks and their results and the EE and DR bundling workbooks.

13. Restructure the DSM bundles so they are not grouped by cost-effectiveness alone.

14. Use marginal peak and energy line losses (not average losses) to convert meter savings to generator savings.

15. Subtract avoided T&D benefits from MPS costs if not already captured in IRP modeling.

16. Clarify which resources are going-in projects.

17. Clarify how the upcoming dispatchable RFP will affect modeled resource costs. 18. Explain why new resources are generally not modeled before 2033.

19. Explain whether modeling will account for:

- Renewable Portfolio Standard (RPS) requirements through 2045.
- Stranded asset risks for new gas turbines.
- Hydrogen conversion costs to meet long-term RPS mandates.