

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

**IN THE MATTER OF THE PUBLIC SERVICE COMPANY)
OF NEW MEXICO'S REVISED RENEWABLE ENERGY)
PORTFOLIO PROCUREMENT PLAN FOR 2012,) Case No. 11-00265-UT
)
PUBLIC SERVICE COMPANY OF NEW MEXICO,)
)
Petitioner,)
_____)**

**INITIAL POST-HEARING BRIEF OF
RENEWABLE ENERGY INDUSTRIES ASSOCIATION OF NEW MEXICO**

Respectfully submitted,

Bruce C. Throne
Attorney at Law
1440-B South St. Francis Dr.
Santa Fe, NM 87505
Telephone: (505) 989-4345
Fax: (505) 820-2560
Email: bthroneatty@newmexico.com

Attorney for REIA

FILED: November 18, 2011

The Renewable Energy Industries Association of New Mexico (“REIA”) submits this Initial Brief in accordance with the Hearing Examiner’s November 8, 2011 Order.

STATEMENT OF REIA’S POSITIONS

REIA urges the Commission to reject and modify the Renewable Energy Portfolio Procurement Plan for 2012 (“2012 Plan”) proposed by Public Service Co. of New Mexico (“PNM”) in this case as recommended by REIA’s witness, Randall Sadewic, and further set forth below. Specifically, REIA recommends that the Commission:

- approve REIA’s proposal, and reject PNM’s proposal in its Rebuttal testimony, for extending the 0 to 10 kW and >10 to 100 kW tranches of PNM’s existing Solar Incentive Program (“SIP”) when they become fully subscribed;
- reject the non-levelized method PNM used to calculate the annual (“net revenue requirements”) and rate impacts of its proposed 2012 Plan;
- adopt instead a levelized method to calculate those costs that reasonably includes the “life cycle” avoided capacity cost benefits provided by the *PNM-owned* 22 MW of PV and Solar Demo with Batteries (“Solar Demo”) resources approved by the Commission in Case No. 10-00037-UT and by PNM’s Power Purchase Agreement (“PPA”) with the New Mexico Wind Energy Center (“NMWEC”);
- use the \$926.4 million and \$936.0 million revenue “approximations” for 2012 and 2013 provided by PNM and shown on Exhibit RS-7 to Mr. Sadewic’s Direct Testimony (REIA Ex. 2) as the best and most reliable evidence provided by PNM, before the hearing concluded, of its projected aggregated overall electric charges in those years to determine the Commission’s RCT limits in this case;
- reject PNM’s proposals (in its Rebuttal Testimony and November 10, 2011

- “Responses to Hearing Examiner’s Bench Requests”) that, when projecting its 2012 and 2013 revenues to determine its RCT limits, it be allowed to remove or exclude revenues “associated with the Rule 570.10.C large customers” and from charges for its demand-side response and energy efficiency programs; and
- reject the “alternate” proposals in PNM’s 2012 Plan to satisfy its Renewable Portfolio Standard (“RPS”) shortfalls in 2012 or 2013 with purchases of unbundled wind RECs without energy until PNM demonstrates that it has satisfied, and will continue to satisfy, its minimum 20% solar diversity requirement *without* any RCT-based RPS or solar diversity requirement reductions.

For the reasons stated in Mr. Sadewic’s Direct Testimony, REIA takes no position on the proposals by PNM, Staff and County of Santa Fe (“SFC”) for extension of the tranches of PNM’s existing SIP for solar systems sized greater than 100 kW-ac up to 1 MW-ac once the capacities of those tranches established by the Commission in Case No. 10-00037-UT are fully subscribed. *For this case only*, due to the Commission’s approval of paragraphs 13 and 30 of the Stipulation in the *Final Order* addressing PNM’s most recent general rate case (No. 10-00086-UT), REIA does not challenge the reasonableness of PNM’s exclusion of avoided fuel, system loss, capacity and other avoided cost benefits from its calculations of the costs of its procurements in its proposed 2012 Plan from its distributed generation (“DG”) programs in 2012 and 2013 when applying the Commission’s RCT.

It is REIA’s position that the \$899,897,069 and \$906,330,656 “Estimated Retail Revenues” in 2012 and 2013, respectively, provided by PNM for the first time after the

hearing in this case in its November 10, 2011 “Responses to Hearing Examiner’s Bench Requests” are better projections of PNM’s aggregated overall annual electric charges based on PNM’s current rates than the “2010 revenues” PNM used to determine its RCT limits in 2012 and 2013 in this case. Due to substantive issues about the reliability and inclusiveness of those revenue estimates and procedural due process problems with Commission reliance on them, however, if the Commission does consider them, it should do so solely for the purpose of assessing the reasonableness of the “2010 revenues” PNM used to determine its RCT limits.

ARGUMENT

I. Background; The Legal, Regulatory and Public Interest Bases for the Commission’s Renewable Energy Diversity Requirements.

Section 62-16-4.A(3) of the New Mexico Renewable Energy Act (“REA”) recognizes that, as in the context of investments in other types of resources, renewable energy resource diversity is important for investor-owned utilities (“IOUs”) and their customers in this State. That statute requires that each utility’s renewables portfolio “shall be diversified as to the type of renewable energy resource, taking into consideration the overall reliability, availability, dispatch flexibility and cost of the various renewable energy resources made available by suppliers and generators.”

Rules 572.7.G and 572.14 implement that statutory diversity requirement, requiring that PNM and the State’s other electric IOUs satisfy their minimum RPS requirement in 2012 (and 2013) with “no less than” 20% solar resources and 1.5% customer-sited DG, increasing to a minimum 3.0% DG requirement beginning 2015. Rule 572.14.D recognizes that DG provides resource diversity benefits to IOUs and their customers *in addition* to those provided by utility-scale renewable resources. It provides

that renewable energy certificates (“RECs”) used to meet the minimum DG requirement “may not also be used to meet a resource-specific diversity requirement.”

The utility customer and public interest bases for the Commission’s decision in 2007 to establish these renewable diversity requirements (virtually all of which PNM opposed) were well-reasoned and thoroughly discussed in the Commission’s *Final Order* in Case No. 07-157-UT, pp. 19-39. The Commission concluded there that, contrary to arguments by PNM, the New Mexico Industrial Energy Consumers and El Paso Electric Co. (“EPE”), “diversity is mandated by the law and is not an option for utilities.” The Commission also explained that language in the REA makes clear that it “was enacted to achieve certain public benefits by regulating the behavior of electric utilities” and was not intended to allow “the development of renewable energy in New Mexico to proceed at the discretion and judgment of utilities.”¹

The Commission’s past approvals of DG REC incentive programs for PNM and the other IOUs has satisfied several other purposes stated in the REA. These include the promotion of “energy self-sufficiency” by utility customers, preservation of “the state’s natural resources,” “improved environment in New Mexico,” and the opportunity to “bring significant economic benefits to New Mexico.”²

For example, it is currently estimated that, for every MW of installed solar power, approximately 35 people are employed, which includes jobs in both manufacturing and installation.³ Mr. Sadewic also explained that the DG REC purchase programs previously approved by the Commission for PNM and EPE provided an essential stimulus that allowed his company, Positive Energy, to grow from four employees in

¹ *Final Order*, Case No. 07-157-UT, p. 22 and n. 9; *see also id.*, p. 34.

² NMSA §§ 62-16-2.A(1) and (2).

³ Sadewic Dir. (REIA Ex. 2), pp. 3-4, 14-15.

2005 to over 46 full-time employees in 2011, and that those programs helped create similar job growth for a number of other New Mexico solar DG businesses.⁴

Thus, as recognized in the REA and Rule 572, aside from the avoided capacity, fuel, system loss, water usage and greenhouse gas emission benefits of solar generation to IOUs and their customers, the installation of solar DG provides *additional* employment and economic development benefits to the State that are not reflected by simple comparisons between the “compliance cost” per MWh of PNM’s projected procurements of RECs from its DG programs with its cost of RECs from other renewable resources in a particular year. Here in New Mexico, where numerous relatively small businesses provide much of the State’s employment and the engine for economic growth,⁵ the broader economic benefits of DG in PNM’s service area cannot reasonably be denied.⁶

When the Commission established the minimum DG, solar and other renewable diversity requirements in 2007, it recognized that, at that time, “[t]he primary form of distribution discussed” was “solar PV, which is a relatively expensive technology.”⁷ The Commission also recognized, however, the longer term benefits of distributed *and* “utility-scale” solar projects to utility customers in New Mexico and that, at that time, the IOUs’ acquisitions of solar resources were “miniscule aside from PNM’s customer-owned small PV incentive program” (which the Commission had somewhat artificially stimulated by providing PNM with a 3:1 weighting for RECs from that program).⁸

⁴ *Id.* REIA’s members include 20 New Mexico small businesses and individuals that employ over 600 persons in this State. *See also* 10/21 Tr. at 110-111 (Blank) (no reason to question recent report by the Solar Foundation that New Mexico currently has 2,099 people working in the solar industry).

⁵ *See, e.g.*, February 2011 “Small Business Profile” for New Mexico published by Small Business Administration, Office of Advocacy (www.sba.gov).

⁶ *See* O’Hare Dir. (SFC Ex. 1), pp. 3-8, 13, 15-17.

⁷ *Final Order*, Case No. 07-157-UT, p. 37.

⁸ *Id.*, pp. 11-18, 34.

The minimum DG “target” initially proposed by the Commission in Case No. 07-157-UT was 10% of each utility’s RPS.⁹ For the reasons noted earlier and because it believed that “even aggressive deployment of distributed generation is unlikely to bring utilities close to this [10%] target prior to 2020,” the Commission decided to lower that target to a “more realistic” 1.5% beginning in 2011, increasing to 3% in 2015.¹⁰

The *Final Order* in Case No. 07-197-UT shows that the Commission’s decision in 2007 to reduce its initially proposed minimum DG diversity requirement for all of the IOUs from 10% to 1.5% “by no later than January 1, 2011” was not based on any examination or determination at that time of the relative *long-term* costs and benefits of DG as compared to utility-scale renewable resources. That decision was based on the Commission’s concern at that time that requiring a 10% DG target might jeopardize a utility’s ability to satisfy its other diversity requirements within its RCT in a timely manner. To provide sufficient time for all IOUs to comply with its diversity requirements, the Commission’s *Final Order* extended the time for compliance it had initially proposed (January 1, 2009) by two years, until January 1, 2011.¹¹

PNM did not challenge the lawfulness of the diversity requirements in the *Final Order* in Case No. 07-157-UT. Nevertheless, it failed to satisfy its 20% solar diversity requirement in 2011. Now, in this case, PNM attempts to evade compliance with that requirement in 2012 and 2013 by relying on a number of unreasonable manipulations of the methods it uses to apply the Commission’s RCT, addressed below.

⁹ *Id.*, p. 23.

¹⁰ *Id.*, p. 37. The Commission also eliminated prospective 3:1 weighting for solar RECs. *Id.*, pp. 17-18.

¹¹ *Id.*, p. 39.

II. PNM's Last (Revised 2011) Plan Case, No. 10-373-UT.

In its Revised 2011 Plan Case No. 10-373-UT, PNM requested a Commission variance from its 20% solar diversity requirement in 2011, claiming it could not satisfy that without exceeding the Commission's RCT.¹² The Commission's *Final Order* in that case adopted the Hearing Examiner's recommendation that PNM be granted a variance from that solar (and its "other" resource) diversity requirement *on the condition* that it satisfy that requirement by "no later than April 5, 2015."¹³ The Commission rejected PNM's argument that the high cost of solar energy and the absence of Commission guidance about an appropriate methodology for calculating the RCT made it virtually impossible for PNM to meet its 2011 diversity requirements "even by April 2013," finding those arguments "nothing more than excuses for self-fulfilling future failures."¹⁴

Neither the Recommended Decision nor the *Final Order* resolved the reasonableness of the changed method PNM used to calculate the annual procurement costs from its owned 22 MW of PV and Solar Demo resources when applying the RCT. Instead, the *Final Order* adopted the Recommended Decision's conclusion that adoption of an approved methodology for applying the RCT was "not necessary to the resolution of" that case and stating: "[t]he Commission recognizes that there is a need for additional guidance with respect to the calculation of the RCT and there may be a need to address the RCT in connection with PNM's plan."¹⁵

On July 1, 2011, PNM filed a motion for rehearing of the *Final Order* that was granted on July 18, 2011. One of the grounds for that PNM Motion (in § II, pp. 5-6) was

¹² See *Recommended Decision* adopted in 6/2/11 *Final Order* in Case No. 10-373-UT, p. 60.

¹³ *Final Order*, Case No. 10-373-UT, ¶ 14; see also *Recommended Decision*, pp. 58-69.

¹⁴ *Final Order*, Case No. 10-373-UT, ¶ 4.

¹⁵ *Id.*, ¶ 6; see also *Recommended Decision*, p. 72.

that the *Final Order* was “unreasonable and unlawful in failing to make clear that PNM’s obligation to satisfy its diversity requirements for solar and ‘other’ technologies is subject to the reasonable cost threshold.”

The Commission’s *Final Order Upon Reconsideration* stated, *inter alia*:

With respect to the interaction of the diversity requirements and the RCT, this is clearly stated in the rule: “Public utilities shall not be required to provide a fully diversified renewable portfolio when doing so would conflict with reasonable cost thresholds established by the Commission. 17.9.572.14(B) NMAC. The Final Order should not be read to provide a different result.”¹⁶

PNM next filed a *Motion for Expedited Clarification of Final Order Upon Reconsideration* in that case. In its October 11, 2011 *Order Denying Motion for Clarification*, the Commission again made clear its decision to defer addressing the reasonableness of PNM’s RCT calculation methods until this case, indicating it intended to make “factual findings” concerning those matters, stating:

Staff is correct that the Commission did not grant PNM a permanent waiver for its 2011 RPS shortfall, and that while it is likely that a future make-up for 2011 will be foreclosed by Reasonable Cost Threshold (RCT) constraints, the possibility of a future make-up necessarily persists *pending factual findings on the RCT in a subsequent proceeding*.¹⁷

III. REIA’s Proposed Extension of the SIP for Systems 100 kW and Smaller is Reasonable, in the Public Interest and Should be Approved in this Case.

PNM’s initial 2012 Plan did not include any proposal for extending the SIP to its customers for systems with a capacity of 100 kW-ac or smaller after those two SIP “tranches” become fully subscribed with completed applications. Ms. Bothwell testified that PNM did not include such a proposal in its initial Plan “because “those tranches are not expected to be filled in the next year.”¹⁸

¹⁶ *Final Order Upon Reconsideration*, Case No. 10-373-UT, ¶ 4.

¹⁷ *Order Denying Motion for Clarification*, Case No. 10-373-UT, ¶ 5 (emphasis added).

¹⁸ Bothwell Dir. (PNM Ex. 8), p. 26.

In response, Mr. Sadewic provided a number of reasons why it was not reasonable or in the public interest for the Commission to approve PNM's proposal to wait to address those matters until PNM provides notice that those tranches are nearly filled.¹⁹ They included: the likelihood that those tranches will be nearly filled within a short time after the Commission decides this case, or well before PNM submits its next (2013) Plan on July 1, 2013; and the language in paragraph 41 of the *Final Order* in Case No. 10-00037-UT stating: "If PNM has reason to believe based on the actual participation trends in a particular program that waiting until the next-to-last tranche has been consumed will not provide sufficient time for the Commission to take appropriate action as described herein, the company shall provide sooner notice" of those participation trends.

Mr. Sadewic explained why the notice and 15-day proposal procedure established in that *Final Order* will not provide "sufficient time" for the Commission to take "appropriate" action regarding those SIP matters. He also addressed the "substantial negative impact" this sort of delay would have on the solar DG market and associated employment and business activity in New Mexico, and the problems with addressing these SIP matters outside one of PNM's procurement plan cases in the context of PNM's other renewable procurements and the Commission's RCT. He also addressed the significant resource burden such a separate additional Commission proceeding to address these SIP matters would impose on REIA and other interested parties.²⁰

To address these concerns, Mr. Sadewic recommended that the Commission decide in this case that, if and when either of those tranches becomes fully subscribed, they should be extended and modified as follows for any further applications:

¹⁹ Sadewic Dir., pp. 10-18.

²⁰ *Id.*

- For an initial “Tier 1” period of six months from the date on which PNM determines the tranche has been fully subscribed, the price for RECs offered should be reduced to \$0.055 per kWh, which would be ½ ¢ per kWh less than the lowest price step in those tranches under PNM’s existing SIP.
- The price for RECs offered thereafter should be reduced by an additional ½ ¢ per kWh every six months thereafter for a period of two years.
- At the end of that two-year period, the price for RECs for systems of those sizes should be reduced to \$0.03/kWh until otherwise ordered by the Commission.

The following table summarizes this REIA proposal:

<u>Tier</u>	<u>Period</u>	<u>REC Price per kWh</u>
1	6 months from tranche closure	\$0.055
2	6 months from Tier 1 closure	\$0.050
3	6 months from Tier 2 closure	\$0.045
4	6 months from Tier 3 closure	\$0.040
5	Until otherwise ordered by PRC	\$0.03 ²¹

REIA also proposes that, instead of the fixed contract lengths of 12 or 20-years in the existing SIP, all new REC contracts offered by PNM during this extension of these SIP tranches should have a common termination date of December 31, 2020. REIA proposes that the Commission order that all other terms and conditions set forth in PNM’s current SIP tariffs on file with the Commission should remain unchanged. For example, as provided in PNM’s current standard Application forms for the SIP, applicants for the 0 to 10 kW tranche would be required to complete construction of the solar facility applied for within 9 months of PNM’s “Screening Passed Date,” and

²¹ *Id.*, p. 19.

applicants for the 10 to 100 kW tranche would have to complete construction of the solar facility applied for within 12 months of their “Screening Passed Date.”²²

Mr. Sadewic explained why approval of this REIA proposal is reasonable, consistent with the REA and in the public interest. By approving this proposal at this time, the Commission will act in a timely and appropriate way to prevent the sort of automatic closure of these tranches for smaller solar DG systems in this size range for an indefinite time period that otherwise could occur and negatively impact businesses that provide these systems and related employment and economic development in PNM’s service area.²³ This is consistent with the finding in section 2 of the REA that “the use of renewable energy by public utilities subject to Commission oversight in accordance with the REA can bring significant economic benefits to New Mexico.”²⁴

REIA’s SIP extension proposal also is consistent with the finding in section 2 of the REA that “the generation of electricity through the use of renewable energy presents opportunities to promote energy self-sufficiency, preserve the state’s natural resources and pursue an improved environment in New Mexico.” It would promote energy self-sufficiency by more of PNM’s residential and small business customers and help reduce PNM’s future dependence on fossil-fueled generation resources, such as coal and natural gas, that produce greenhouse gas emissions and consume large amounts of water in New Mexico where water resources are scarce. REIA’s SIP proposal also is consistent with the finding in section 2 of the REA providing that “a public utility should have incentives to go beyond the minimum requirements of the renewable portfolio standard.”²⁵

²² *Id.*, p. 20.

²³ *Id.*, p. 20.

²⁴ *Id.*, p. 21.

²⁵ *Id.*

Mr. Sadewic explained that three features of the tiered, declining REC pricing structure in REIA's SIP extension proposal reasonably address the Commission's goal of ensuring that PNM's customers do not pay unreasonable amounts for RECs from these systems. First, the prices offered for RECs from systems in this size range will drop by ½ cent per kWh for a six-month period from the lowest (\$0.06) price offered in those tranches in PNM's existing SIP, and will continue to decline by ½ cent per kWh during each subsequent six month period for two years before dropping to \$0.03 per kWh until the Commission determines otherwise. This declining price structure is consistent with the fact that, though some PV system installation costs in New Mexico (e.g., copper, steel and labor costs) have recently increased, PV module costs, which constitute a substantial portion of the total installation cost of PV systems, have been declining over the past 30 years and are expected to continue to decline in the future.²⁶

Mr. Sadewic explained that the December 31, 2020 common termination date proposed for all new REC purchase contracts would reduce the total (long-term) cost of the SIP extensions proposed by reducing the lengths of those contracts on a monthly basis, as compared to the currently *fixed*, 12-year contract periods for participants in the 0 to 10 kW tranche and the 20-year contract periods for participants in the >10 to 100 kW tranche of the existing SIP approved by the Commission. For example, if either of those tranches becomes fully subscribed on December 31, 2011, the *longest* REC purchase contract PNM would be required to offer a subsequent participant in those tranches (i.e., that submits a completed application to PNM on January 2, 2012) would be nine years. If either of those tranches becomes fully subscribed on March 31, 2011, the longest REC contract PNM would be required to offer a subsequent participant in those tranches (i.e.,

²⁶ *Id.*, p. 22.

that submits a completed application to PNM on April 1, 2012) would be eight years and nine months, and so forth, with the maximum contract length declining each month.²⁷ This feature is similar to the common contract termination date in the tiered pricing structure for EPE's "Small and Medium System REC Purchase Programs" (for solar and wind systems sized 100 kW or less) in an unopposed Stipulation supported by Staff currently proposed in Case No. 11-00263-UT).²⁸

REIA's tiered pricing proposal for these SIP tranche extensions is time period-limited, rather than capacity-limited. This feature also is similar to the tiered pricing structure for EPE's "Small and Medium System REC Purchase Programs" supported by Staff and proposed in the uncontested Stipulation pending in Case No. 11-00263-UT).²⁹

Mr. Sadewic testified that REIA's proposed time-limited pricing structure will provide several benefits to PNM's customers compared to the capacity-limited pricing structure in PNM's existing SIP. It will reduce the cost per kWh for RECs during each successive six-month period regardless of how much additional capacity is applied for during any of those periods and how much of that capacity is actually interconnected with PNM's grid. It also will provide clearer advance notice to PNM's customers of the REC price that will be available when they are deciding whether to invest in a solar DG system in this size range. Further, in contrast to a capacity-limited SIP tranche approach, it will prevent the potential scenario where one applicant could apply for a relatively large amount of capacity within a tranche but not install that capacity within the 9 or 12-month installation deadline required in PNM's SIP tariffs, thereby preventing other customers

²⁷ *Id.*, pp. 22-23. Mr. Sadewic also compared this cost reduction feature to other fixed 12-year and 10-year REC purchase contract lengths previously approved by the Commission for EPE and SPS. *Id.*, pp. 23-24.

²⁸ *Id.*, p. 23 and Ex. RS-4.

²⁹ *Id.*, p. 24 and Ex. RS-4.

from participating in the SIP.³⁰ Retaining the existing 9-month and 12-month installation deadlines in PNM's SIP will prevent applicants from prematurely locking in higher REC prices by submitting applications before they have truly decided to proceed with installation of a solar DG system in this size range.³¹

Mr. Sadewic did not address PNM's proposed extension of its existing SIP for projects 100 kW up to 1 MW. He and REIA left it to other parties to address that subject for the following reasons:

As shown on PNM's current Rate No. 32, the Commission approved a total capacity of 17.48 MW-ac for solar DG systems sized greater than 100 kW-ac for the SIP in Case No. 10-00037-UT. Though a substantially lower number of system applications in those size tranches is expected to fill those tranches, due to the estimated kWh production from those systems and the 20-year REC contracts established by the Commission for participants in those tranches, the annual and total costs of those REC procurements in 2012 and subsequent years is expected to be substantially greater than the annual and total costs of PNM's REC procurements from the two smallest size tranches of the SIP that REIA's proposal addresses. REIA believes the installation of greater numbers of smaller solar DG systems in the 100 kW or lower size range generates more economic development benefits in New Mexico in terms of local value-added labor, engineering services, and components than the installation of a substantially lower number of solar DG systems sized larger than 100 kW. Also, most of the PV installations by REIA's members are in this smaller size range.³²

At the hearing, Mr. Sadewic projected that Commission approval of REIA's SIP extension proposal could result in interconnection of an additional 5 MW of DG in the first 12 months and an additional 5 MW in the second 12 months to PNM's system after the total capacity allocated by the Commission for the existing 100 kW and smaller SIP tranches is fully subscribed.³³ Those projections are reasonable considering PNM's

³⁰ *Id.*; see also 10/25 Tr. at 46-48 (Sadewic).

³¹ Sadewic Dir., pp. 24-25.

³² *Id.*, pp. 25-26.

³³ 10/25 Tr. at 20 (Sadewic).

projected subscriptions in 2011 for its existing SIP,³⁴ the REC prices in REIA's proposal that are lower than *the lowest* REC prices offered in the existing SIP, and the declining REC purchase contract lengths proposed that are substantially shorter than the 12-year and 20-year contract lengths in the existing SIP for systems of these sizes.³⁵

Based on those capacity projections, Mr. Sadewic estimated that the additional cost of this REIA proposal to PNM and its customers would be about \$313,000 for the first 12 months and about \$726,000 for the second 12 months after these tranches of the existing SIP are filled.³⁶ He testified that, to be conservative, assuming those tranches are filled by January 1, 2012 and all of that additional DG capacity is installed, interconnected and producing RECs during 2012 and 2013, those additional costs would constitute about 1.5% and 3.0% of PNM's RCT limits in 2012 and 2013 (if those limits are based on PNM's "approximations" that, under its *current* rates, its total annual retail charges in those years will be \$926.4 million and \$936.0 million, respectively).³⁷

Mr. Sadewic testified that the lower REC prices in REIA's proposal do not show or suggest that the lowest REC price offered for those systems in the existing SIP is "too high," explaining that REIA proposed those lower incentives to present a proposal it believed "would be accepted."³⁸ He also disagreed with PNM's counsel that the proposed time-limited declining price structure would not allow an accurate projection of the costs of REIA's SIP extension proposal, explaining that, based on historic participation rates in PNM's SIP, the Commission can reasonably project those costs.³⁹

³⁴ See Bothwell Reb., Ex. CDB-6R (2011 actual and projected "Existing SIP" subscriptions).

³⁵ 10/25 Tr. at 14-17, 41-42 (Sadewic).

³⁶ *Id.*, at 20-21 (Sadewic).

³⁷ *Id.*, at 20 (Sadewic); see also Sadewic Dir., pp. 42-44 and Ex. RS-3.

³⁸ 10/25 Tr. at 21-22 (Sadewic).

³⁹ *Id.*, at 39-40 (Sadewic).

In Rebuttal, Ms. Bothwell asserted that, as shown on her Exhibit CDB-6R, REIA's SIP extension proposal "would raise costs by at least \$1.5 million annually and that "[t]he additional cost would double the money that PNM ratepayers would be spending on the most expensive category of renewable energy."⁴⁰ There are a number of reasons why the data on Exhibit CDB-6R does not support rejection of REIA's proposal.

First, as shown on that PNM Exhibit, Ms. Bothwell's \$1.5 million "additional cost" calculation is based on an unrealistic "interconnection rate" assumption of "3 MW per 6 months," or 6 MW per year. That assumption fails to consider the financial impacts on potential applicants of the lower REC prices and substantially shorter REC purchase contract lengths (declining monthly) proposed by REIA, compared to the REC prices and 12-year and 20-year REC purchase contract lengths approved for PNM's existing SIP. As indicated in the data labeled "Existing SIP" on Exhibit CDB-6R, even at those higher REC prices and with those substantially longer REC contract lengths *and* the substantial rate increase PNM implemented in August of 2011, PNM forecasts that only 5.5 MW of additional solar DG will be "subscribed" in 2011. Ms. Bothwell's assumption that additional DG capacity will be interconnected and actually producing RECs at a *faster* rate when customers are offered lower REC prices for substantially shorter contract periods is not reasonably justified in her or PNM witness Styes' Rebuttal Testimony.

Moreover, as shown on Ms.Bothwell's Exhibit CDB-6R, even accepting her "interconnection rate" assumptions, the additional costs of REIA's SIP extension proposal are only \$193,050 in 2012 and \$895,050 in 2013, compared to Mr. Sadowek's cost calculations of approximately \$313,000 in 2012 and \$726,000 in 2013, noted earlier. By either calculation, those amounts constitute a very small percentage of PNM's RCT

⁴⁰ Bothwell Reb., p. 28.

limits and are well within the RCT “headroom” available in 2012 and 2013 if the Commission uses PNM’s current rates to project those RCT limits in this case.

The calculations on Ms. Bothwell’s Exhibit CDB-4 (challenged below) show that, considered on a “net revenue requirements per MWh-REC” basis, the costs of PNM’s procurements from its *utility-owned* 22 MW of PV and Solar Demo resources are substantially *higher* in 2012 and 2013 than the costs of most of the RECs PNM expects to acquire from its *existing* SIP. Thus, neither PNM’s existing SIP nor the SIP extension proposed by REIA is “the most expensive category of renewable energy” proposed in PNM’s 2012 Plan, as Ms. Bothwell asserts. And, as discussed below, Ms. Bothwell’s argument that the Commission should not adopt REIA’s SIP extension proposal based on her projections of its costs *after 2013* is divorced from, and not supported by, any reasonable or meaningful RCT analysis applicable to *those* years.

SIP (100 kW or Smaller) Extension Proposals by Other Parties

Citing PNM witness Ortiz’s acknowledgement of the harm to economic development that could result from abrupt termination of the SIP for systems sized 100 kW to 1 MW, SFC witness O’Hare, the County’s Energy Programs Specialist, also recommends that the Commission address extension of the SIP for systems 100 kW and smaller in this case because that economic harm is “equally true for the smaller size categories as well.”⁴¹ Mr. O’Hare (like Mr. Sadewic) recommends that the Commission extend those SIP tranches when their lowest (6¢/kWh) price step for RECs is exhausted, beginning at 5.5¢/kWh and decreasing by ½ ¢/kWh “every six months or, as before, with every 0.5 or 0.6 MW of deployment,” terminating thereafter at “a 3 to 4 cents/kWh level”

⁴¹ O’Hare Dir. (SFC Ex. 1), pp. 16-17, *citing* Ortiz Dir., p. 14.

so those incentives “continue for at least another two to three years.”⁴² Mr. O’Hare explained that, since “solar continues to be somewhat more expensive in the immediate term than traditional power sources,” like the current federal and state solar income tax incentives that “have sunset clauses for a little later this decade,” these continuing REC incentives should be considered “bridging incentives” necessary to provide sufficient time for their cost to reach “grid parity.”⁴³

Staff witness Lamberson testified that continuing Commission approval of REC incentives “to promote the use of DG technologies such as solar and wind” until the prices of these technologies “are at parity with other resource options” is important because it promotes “research and development in those technologies, as well as production improvement that reduce prices and improves the reliability of the technologies” and helps “create local jobs in support of the industry,” consistent with the goals of the REA.⁴⁴ For those reasons, he too recommends that the Commission act in this case to extend the SIP for systems 100 kW and smaller (and up to 1 MW) in a manner similar to Mr. Sadewic’s recommendation.

Mr. Lamberson recommends that REC contract lengths for all new participants in those (and all other) SIP tranches either be limited to 8 years or, as Mr. Sadewic recommended, expire at the end of 2020 and thus result in “shorter contract terms over time.” He (like Mr. Sadewic) recommends that tranche extensions for new applicants “be time limited as opposed to capacity limited,” and that “each tranche and related REC incentive price...be effective for a 6-month window, regardless of how much capacity is installed in each tranche.”

⁴² *Id.*, p. 18.

⁴³ *Id.*

⁴⁴ Lamberson Dir. (Staff Ex. 1), pp. 21-22.

The principal differences between Staff's and REIA's proposals for extending the SIP for systems 100 kW and smaller are that Staff's proposal would become effective on January 1, 2012 (rather than when those tranches are filled) and Staff recommends a one cent (rather than ½¢) per kWh reduction in REC incentive payments for all DG program classifications for each six month period going forward "based on current REC incentive prices."⁴⁵ REIA believes Staff's proposal, like REIA's, is more reasonable and consistent with the public interest than the "interim" proposal offered by PNM for the first time in its rebuttal testimony.

In Rebuttal, PNM witness Ortiz retreated from PNM's initial position that it was not necessary for PNM or the Commission to address any extension of the SIP for systems 100 kW or smaller in this case. He testified that subscriptions for those categories of the SIP "have nearly reached the next to last tranche due to the large number of applications received in August, September and October" and that "PNM anticipates making the required notification to the Commission in the coming weeks."⁴⁶ He testified that "[b]ecause the timing of the full subscription of the next to last tranche of these smaller sized categories will not coincide with the filing of PNM's 2013" Plan, PNM has the following "interim proposal to purchase RECs produced by systems 100 kW and smaller while the Commission considers PNM's recommendations regarding the continued purchase of RECs from" those systems:

PNM will file its Notice as the next to last price step of either of the two categories for solar systems at or below 100 kW_{AC} nears full subscription, and very soon thereafter will file a recommendation regarding whether and under what terms and conditions these SIP categories should be continued. While PNM's proposal is pending before the Commission, PNM will continue to accept applications for both categories until they are fully subscribed, at which time, if

⁴⁵ *Id.*, pp. 22-23.

⁴⁶ Ortiz Reb. (PNM Ex. 3), pp. 9-10.

there has been no final Commission action on the proposal, PNM proposes to continue to accept applications. Similar to the design of the current program, PNM will reduce the price in each category by one cent (\$0.01 per kWh), using the same price steps in the current program – 593 kW for systems 10 kW and smaller, and 450 kW for systems between 10 kW and 100 kW, for either six months or until the Commission has issued an order on PNM’s REC purchase continuation proposal, whichever is sooner. PNM also proposes that the term of the REC purchase contract be reduced to 8 years for these interim subscriptions as recommended by Mr. Sadewic [sic]. PNM asks the Commission to approve this interim proposal in this case to remove uncertainty for customers considering small PV installations as the current program becomes fully subscribed.⁴⁷

At the hearing, Mr. Sadewic testified that REIA opposes this PNM “interim” proposal because of its short-term nature, which would be a “disaster” for a business and mean “that we have to come back to renegotiate the incentive program no later than six months from now.”⁴⁸ As noted earlier, Mr. Sadewic explained why addressing extension of the SIP for systems 100 kW and smaller in the sort of “interim” and piecemeal manner proposed by PNM, outside the scope and context of one of PNM’s renewable energy procurement plans and plan costs, is unwise and contrary to the public interest.⁴⁹

In his Rebuttal Testimony, Mr. Ortiz offered the following “general observations” critical of the SIP extension proposals “by the other parties”:

These recommendations ignore the fact that the RECs that PNM acquires through this program are among the highest cost RECs in PNM’s renewable energy portfolio, and that PNM is already well positioned relative to the distributed generation diversity requirements in Rule 572. These facts are relevant because the continued purchase of these relatively expensive RECs will impair PNM’s ability to acquire less expensive RECs within the RCT constraint. This will either result in PNM acquiring less renewables in total if PNM is RCT constrained, or increase RPS compliance costs if PNM is not RCT constrained. PNM’s proposal recognizes the fact that PNM no longer needs DG RECs specifically, but proposes to continue to acquire them as long as they are competitive with other sources of RECs. It must also be remembered that customers with PV systems also receive a significant benefit in the form of net metering, on top of any REC purchases by

⁴⁷ *Id.* As noted, Mr. Sadewic recommended approval of a common Dec. 31, 2020 REC contract termination date—not fixed 8-year contracts-- for all participants in the SIP extensions he proposed.

⁴⁸ 10/25 Tr. at 10 (Sadewic).

⁴⁹ Sadewic Dir., pp. 16-18.

PNM. PNM, therefore, opposes the proposals put forth by other parties and Staff.⁵⁰

Mr. Ortiz’s “general observations” distort and omit relevant facts. As shown on Ms. Bothwell’s Exhibit CDB-4 and noted earlier, based on *PNM’s* “compliance cost” (i.e., “net revenue requirements” \$/MWh per REC) calculations (which exclude *any* avoided cost benefits from solar DG, including solar DG installed under the SIP), the *only* “compliance cost” for RECs from the SIP greater than the “compliance cost” of RECs from PNM’s *utility-owned* solar resources (\$480.14/MWh for Solar Demo and \$142.27/MWh for PNM Owned PV 22 MW) in the plan year (2012) is at the *highest* SIP price step (\$152.11/MWh at the \$0.14/kWh incentive level, including WREGIS costs), *which is already fully subscribed and no longer offered*. Even accepting PNM’s RCT cost-calculation methods (addressed below), the “compliance costs” of procurements from PNM’s *owned* solar resources are substantially higher than the compliance costs per MWh-REC of most of the capacity steps in PNM’s existing SIP in 2012 and 2013.

Second, REIA’s proposed extensions of the SIP—and SFC’s and Staff’s, for that matter—propose declining incentives that are *even lower* than the lowest REC prices in PNM’s existing SIP. Therefore, Mr. Ortiz’s comparison between the compliance costs of those proposals and the compliance costs of its procurements from its *existing* SIP is misleading in terms of application of the Commission’s RCT to those proposals.

It is true that, as indicated on Ms. Bothwell’s Exhibit CDB-4, the compliance cost per MWh-REC of REIA’s proposed extension of the SIP would be greater than the compliance cost per MWh-REC of PNM’s procurements of RECs bundled with wind energy from NMWEC and the compliance cost per MWh-REC of *one-time* purchases of

⁵⁰ Ortiz Reb., p. 7.

unbundled wind RECs *without* energy (proposed by PNM if it is required to satisfy its RPS without its claimed RCT reductions) in 2012 and 2013. PNM procurement of more wind RECs (with *or* without energy), however, will not move the Company closer to satisfying the Commission’s minimum 20% solar diversity requirement in 2012 or 2013. To the contrary, it will move PNM *further away* from satisfaction of those requirements and compliance with the Commission’s 2011 solar diversity variance condition in Case No. 10-373-UT, noted earlier.

Mr. Ortiz’s “general observations” also ignore the fact that, unlike the *single-year* RPS compliance benefits of PNM’s proposed unbundled wind REC (without energy) purchases at lower REC prices (that would cost PNM’s customers approximately \$2.8 million in 2012 and \$3.5 million in 2013), customer participation in the SIP extension proposed by REIA (and SFC) would provide PNM and its customers with much *longer-term* (multi-year) RPS compliance benefits throughout the terms of their REC purchase contracts with PNM, and even longer term avoided capacity, fuel, system loss cost and environmental benefits throughout the useful lives of the systems installed. REIA’s SIP extension proposal also would provide *additional* employment and economic benefits in PNM’s service area (compared to whatever past economic benefits were created by the installation of those wind facilities by other utilities outside PNM’s service area) that, as noted earlier, are not reflected in Mr. Ortiz’s simple RPS “compliance cost” comparisons.

The REC prices PNM customers would pay in rates for REIA’s SIP extension proposed would subsidize only a portion of the up-front capital investments *customers make* to install a PV system (i.e., taking into account the 30% federal and 10% New Mexico investment tax credits currently offered to taxpaying customers). As noted

earlier, Messrs. Sadewic, Lamberson and O'Hare explained that, notwithstanding the net metering benefits to customers that install solar DG systems, extension of those incentives at reasonable levels for the next two to three years is necessary to support continuation of those investments by PNM's customers and promote solar technology development until the cost of solar reaches grid parity.

Mr. Ortiz's "general observations" also ignore the facts that, under the REA and Rules 572.7.G(2) and 572.14.D, PNM's RPS and DG requirements are *minimum* ("no less than") requirements that increase, to 15% and 3% respectively of its retail sales in 2015, and that RECs used to meet those DG requirements "may not also be used to meet a resource-specific diversity requirement." They also ignore the fact that PNM clearly needs more solar procurements in 2012 *and* 2013 to satisfy its minimum 20% solar diversity requirements and the 2011 solar diversity waiver condition in the Commission's *Final Order* in Case 10-373-UT if its RPS for those years is not reduced by its claimed "RCT constraints," the unreasonableness of which is addressed below. REIA believes the following data shows that PNM's solar diversity shortfalls in those years will be even greater than the 16.4% in 2012 and 18.2% in 2013 shortfalls claimed on "Corrected Table C" to Ms. Bothwell's Direct Testimony (p. 20).

Table 1 of PNM's 2012 Plan and Ms. Bothwell's Exhibit CDB-2 Corrected ("Table 2") show that PNM's RPS after its "Adjustments for Large Customers," *before its further "Adjustments for the RCT,"* is 843,991 MWh in 2012 and 852,720 MWh in 2013. Per Rule 572.14.D, 1.5% of PNM's RPS (12,660 MWh/RECs in 2012 and 12,791 MWh/RECs in 2013) satisfied by DG cannot be used to satisfy PNM's 20% solar diversity requirement in those years.

As shown on Ms. Bothwell's Exhibit CDB-4 Corrected, PNM projects a total of 75,192 MWh/RECs in 2012 and 85,873 MWh/RECs in 2013 from its DG Programs. The remaining or excess solar DG RECs projected by PNM (62,532 MWh/RECs in 2012 and 73,082 MWh/RECs in 2013), plus the RECs from PNM's *owned* solar resources (52,431 MWh/RECs in 2012 and 52,163 MWh/RECs in 2013), would provide PNM with a total of 114,963 solar MWh/RECs in 2012 and 125,245 solar MWh/RECs in 2013. Those solar totals will satisfy only 13.6% of PNM's Large Customer-adjusted RPS in 2012 and 14.7% of its Large Customer-adjusted RPS in 2013 if its RPS is not further reduced based on PNM's challenged RCT calculations.

As REIA shows in the following section, when the RCT is reasonably and appropriately applied to the renewable procurements in PNM's proposed 2012 Plan, there is more than sufficient RCT "headroom" in 2012 and 2013 for REIA's proposed extensions of the SIP for systems 100 kW and smaller, and for additional procurements of solar energy to satisfy the Company's minimum solar diversity requirements without any *RCT*-based reductions to those requirements or its RPS.

IV. PNM's Proposed Methods for Calculating the Costs of its 2012 Plan and its RCT Limits Should be Rejected; Instead, Based on the Record and Applicable Law, the Commission Should Use (i) Reasonable 2012 and 2013 PNM Revenue Projections Based on PNM's *Current* Rates, Including Revenues from its Large Rule 572.10.C Customers and its Demand Response/Energy Efficiency Charges, to Calculate PNM's RCT Limits and (ii) a Levelized Cost Method that Includes the Reasonable Avoided Capacity Cost Benefits of PNM's *Owned* Solar Resources to Calculate the Annual Costs ("Net Revenue Requirements") and Rate Impacts of those Resources.

The stated purpose of Commission Rule 572 is "to implement" the REA "and to bring significant economic development and environmental benefits to New Mexico."⁵¹ Consistent with that purpose, Rule 572.10 provides that "[i]n developing its renewable

⁵¹ 17.9.572.6 NMAC.

energy portfolio, a public utility *shall take into consideration* the potential for environmental and economic benefits to New Mexico.”⁵²

Consistent with the REA (§ 62-16-4.A), Rule 572.11.A provides: “a public utility shall not be required to add renewable energy to its electric energy supply portfolio pursuant to the renewable portfolio standard, above the reasonable cost threshold established by the commission.” Per Rule 572.11.B, the RCT in 2012 and 2013 is 2.25% and 2.50%, respectively, “of all customers’ aggregated overall annual electric charges” for those years. That is the “denominator” of the RCT analysis, or annual RCT limit.

Neither the REA nor Rule 572 specifies how an IOU should project its revenues to determine its RCT limits in a given year. However, no language in Rule 572.11.B authorizes an IOU to exclude any revenues from any of its “aggregated overall annual electric charges” to any of its customers when making that calculation, and Rule 572.8 states that the Rule “shall be liberally construed to carry out its intended purposes.”

The REA and Rule 572.11 (to date) also do not specify how a public utility should calculate the annual costs of the renewable energy it proposes to add to its supply portfolio.⁵³ Both the REA (§62-16-4.C) *and* Rule 572.11.B do, however, provide *legal* guidance concerning that calculation. They state, in pertinent part, that in “establishing” and “modifying” the RCT, the Commission “shall take into account”:

- (1) the price of renewable energy at the point of sale to the public utility;
- (2) the transmission and interconnection costs required for the delivery of renewable energy to retail customers;

⁵² 17.9.572.10.A NMAC (emphasis added).

⁵³ As discussed below, PNM, SPS, EPE and other parties addressed this matter in Case No. 08-198-UT. The Commission, however, did not issue any final order in that docket and, on June 9, 2011, issued an Order closing that docket and initiating a new rulemaking proceeding, Case No. 11-218-UT, in which no proposed rule or final order was issued by the Commission prior to conclusion of the hearing in this case.

- (3) *the impact of the cost of renewable energy on overall retail customer rates;*
- (4) *the overall diversity, reliability, availability, dispatch flexibility, cost per kilowatt-hour and life-cycle costs on a net present value basis of renewable energy resources available from suppliers; and*
- (5) *other factors, including public benefits, that the commission deems relevant;...*
(Emphasis added).

As shown in the Commission’s record in Case No. 08-198-UT and below, consistent with the foregoing guidance in the REA and Rule 572.11.B, PNM advocated Commission adoption of a standardized “levelized” method to calculate the annual costs of its and other IOUs’ renewables procurements that also was supported by EPE, SPS and other parties in a “consensus” proposal. In Case No. 10-00037-UT, consistent with that legal guidance, PNM used *and asked the Commission to rely on* a levelized cost method that included PNM-“customized” avoided capacity costs (and other avoided cost) benefits to justify the reasonableness of the 22 MW of owned PV and the 0.5 MW Solar Demo Project resources proposed by PNM and approved by the Commission in that case.

The record shows that, in this case, rather than construe Rule 572 “liberally” to carry out its intended purposes, PNM has done exactly the opposite by abandoning those prior positions and unreasonably manipulating virtually every RCT calculation method imaginable to reduce its *minimum* 10% RPS *and* its 20% solar diversity requirements in the REA and Rule 572 in 2012 and 2013 (and subsequent years if those methods are approved) and to justify its proposed limits on extension of its SIP.

A. Reasonable Calculation of PNM’s RCT Limits for 2012 and 2013.

As shown on Ms. Bothwell’s Exhibit CDB-4, PNM used an historic “2010 revenues” amount (\$797,277,195) to calculate its RCT limits (“constraints”) for the 2012

Plan year *and* 2013. The Commission should reject that RCT calculation method in this case as unreasonable and inconsistent with the “intended purposes” of Rule 572.

Mr. Sadewic (and other witnesses) explained that PNM’s 2010 revenues were based on former PNM rates that don’t reflect the \$72.1 million annual revenue increase the Commission granted PNM in Case No. 10-0086-UT and PNM implemented in August of this year, which will remain in effect in 2012 and 2013.⁵⁴ The effect and obvious purpose of PNM’s reliance on that stale rate and unrealistic revenue data to project its RCT limits in 2012 and 2013 are to provide PNM with a basis for *each* of its following claims in this case:

- (i) its claimed *reduction* of its minimum 10% RPS requirement in the REA to “net RPS” percentages of 5.6% in 2012 and 5.7% in 2013 (after applying RPS reductions due to the REA’s annual “cap” on rate increases for its Rule 572.10.C large customers);⁵⁵
- (ii) its claimed reduction of the amount of additional RECs necessary for it to satisfy its minimum 20% solar diversity requirement in Rule 572.7.G;⁵⁶
- (iii) its claim that it will satisfy that *RCT-adjusted and RPS reduced* “20%” solar diversity requirement and comply with the Commission’s 2011 diversity variance requirement in its *Final Order* in Case No. 10-373-UT before April 2012 *without proposing any new solar resource procurements* in its 2012 Plan;⁵⁷

⁵⁴ Sadewic Dir., pp. 41-42; *accord*, Lamberson Dir. (Staff Ex. 1), pp. 9-10; O’Hare Dir., pp. 14-15; Curl Dir. (CCAEx. 1), p. 5; Beach Dir. (NMIPP Ex. 1), pp.15-16.

⁵⁵ 2012 Plan (PNM Ex. 1), p. 6, Table 1 Corrected (claiming *RCT-based* reductions of 348,339 MWh and 347,295 MWh, *in addition to* Large Customer “Adjustments” of 41,045 MWh and 41,017 MWh, to PNM’s RPS in 2012 and 2013, respectively).

⁵⁶ 2012 Plan, p. 9, Table 2.

⁵⁷ *Id.*; *see also* Ortiz Dir., pp. 9-10; Bothwell Dir., pp. 19-20 (based on PNM’s “net RPS” calculations).

(iv) its “alternate” proposal to be allowed to satisfy its “full” RPS requirements in 2012 and 2013 by spending approximately \$ 2.8 million and \$3.5 million in those years to purchase unbundled wind RECs *without any renewable energy*;⁵⁸

(v) its “alternate” proposal to be allowed to satisfy its 20% solar diversity requirement by purchasing unbundled solar RECs *without any solar energy*⁵⁹; and

(vi) its objections to REIA’s SIP extension proposal, and to the SIP extension proposals by Staff and SFC.

Mr. Sadewic testified that the most reasonable way to calculate PNM’s RCT limits in this case is to apply PNM’s *current*, higher rates to the “Projected Retail Sales (MWh)” of 8,843,583 MWh in 2012 and 8,934,983 MWh in 2013 shown on “Corrected Table 1” in PNM’s 2012 Plan and Exhibit CDB-2 (Table 2) to Ms. Bothwell’s Direct Testimony.⁶⁰ Though REIA asked PNM for that calculation in discovery, PNM refused to provide it, claiming it was “irrelevant” and too burdensome for it to do so.⁶¹ Instead, as shown on Exhibit RS-7 to Mr. Sadewic’s Direct Testimony:

PNM stated that “an approximation of projected revenues and the RCT revenue cap could be calculated” by applying the \$72.1 million revenue increase approved in Case No. 10-00086-UT and factoring in PNM’s higher projected retail sales volumes (shown on Table 1 of PNM’s Plan and Ms. Bothwell’s Exhibit CDB-2, which take into account PNM’s estimates of reduced customer electric usage as a result of “approved and projected energy efficiency”) of 8,843,593 MWh in 2012 and 8,934,983 MWh in 2013. As shown there, that results in projected annual PNM revenues of \$926.4 million in 2012 and \$936.0 million in 2013, as compared to the \$797,277,195 PNM used for the denominator of its RCT calculations for both of those years.⁶²

Mr. Sadewic testified further:

⁵⁸ Bothwell Dir., Ex. CDB-4 Corrected, Tables 4&5.

⁵⁹ *Id.*

⁶⁰ Sadewic Dir., p. 43.

⁶¹ *Id.*

⁶² *Id.*, p. 44.

Based on those PNM projected revenue “approximations,” PNM would have an RCT “revenue cap” of \$20.8 million in 2012, or about \$1.5 million greater than the \$19.3 million cost for the “Total Annual Resources” in 2012 shown on Table 4 of Ms. Bothwell’s Exhibit CDB-4 (corrected). Based on those PNM “approximations,” PNM would have an RCT “revenue cap” of \$23.4 million in 2013, or about \$3.9 million greater than the \$19.5 million cost for the “Total Annual Resources” in 2013 shown on Table 5 of that Exhibit.

This shows that, even if the Commission were to accept PNM’s non-levelized procurement cost calculations without considering avoided capacity costs as reasonable for applying the RCT in this case, the annual costs of PNM’s 2012 Plan would be less--rather than more--than its annual RCT revenue caps as shown on Ms. Bothwell’s Exhibit CDB-4. I believe this denominator change alone to PNM’s RCT calculation and analysis would allow PNM to implement the extensions of the SIP REIA is recommending without exceeding its RCT in 2012 or 2013.⁶³

This demonstrates that the RCT basis for PNM’s claimed reductions to its RPS and solar diversity requirements in 2012 and 2013 evaporates if realistic projections of PNM’s retail revenues in those years based on its *current* rates are used to calculate its RCT limits. Mr. Sadewic could not determine from PNM’s discovery responses if PNM’s revenue “approximations” for 2012 and 2013 included revenues from PNM’s charges for its demand-side energy efficiency programs. Based on the language “all customers’ aggregated overall annual electric charges” in Rule 572.11.B, REIA believes those revenues should be included for the purpose of calculating PNM’s RCT limits.⁶⁴ In sum, Mr. Sadewic recommended that the Commission:

use, and direct that PNM use, the \$926.4 million and \$936.0 million projected revenue “approximations” for 2012 and 2013 provided by PNM in discovery and shown on **Exhibit RS-7** to reasonably project PNM’s aggregated overall electric charges in 2012 and 2013 as the “denominator” of PNM’s RCT analysis in this case unless PNM provides more accurate revenue projections for those years, using the rates recently approved by the Commission in Case No. 10-00086-UT, *prior to closure of the record in this case*.⁶⁵

⁶³ *Id.*, pp. 44-45.

⁶⁴ *See also id.*, p. 45; *accord*, O’Hare Dir., pp. 14-15.

⁶⁵ Sadewic Dir., p. 47 (emphasis added).

PNM did not provide any “more accurate” projections of its 2012 or 2013 revenues from its “aggregated overall annual electric charges” based on its current (Case No. 10-0086-UT) rates in its rebuttal testimony *or* at the hearing. On the last day of the hearing, however, the Hearing Examiner issued a bench request for that information.⁶⁶

PNM’s *post-hearing*, November 10, 2011 “Responses to Hearing Examiner’s Bench Requests” assert that, based on projected retail sales of 8,826,372,298 kWh in 2012 and 8,841,606,400 kWh in 2013, its “estimated” revenues (excluding revenues from its Energy Efficiency Rate Riders, voluntary renewables (Sky Blue) program, underground riders, unbilled revenues, franchise fees and gross receipts taxes) are \$899,897,069 in 2012 and \$906,330,656 in 2013. Based (as asserted) on its *current* rates, those appear to better projections of PNM’s aggregated overall annual electric charges in 2012 and 2013 than the “2010 revenues” PNM used to calculate its RCT limits for those years. There are a number of reasons, however, why the somewhat higher revenue “approximations” provided by PNM in discovery, available at the hearing and addressed earlier, are the best evidence of those annual charges, and why it is more reasonable for the Commission to rely on them to determine PNM’s RCT limits in this case.

First, as noted, PNM clearly had an opportunity to provide that information in a *timely* manner in response to REIA’s discovery request, or in its rebuttal testimony, so its reliability could be tested through cross-examination prior to the end of the hearing, but *chose* not to do so. Second, that PNM information is not supported by sworn affidavit, as required by 1.2.25.E(2) NMAC. Nor is it supported by any workpapers showing *how* it was calculated. Further, the “projected retail sales” volumes used to estimate those revenues in 2012 and 2013 are *lower* than the “Projected Retail Sales (MWh) PNM used

⁶⁶ 10/25 Tr. at 65 (Huffman); *see also id.*, at 66-67 (Throne and Huffman).

in its 2012 Plan (p. 6, Table 1 corrected) and Ms. Bothwell's Exhibit CDB-2 Corrected to calculate PNM's RPS. Thus, those estimates are contradicted by the record, unsupported and unreliable for that reason.

The Commission's Rules of Evidence, 1.2.2.35.K NMAC, provide that, where the Commission requires "the production of further evidence upon any issue...[a]ll parties and staff will be given an opportunity to reply to such evidence submitted *and cross examine the witness under oath.*" (Emphasis added). Because that opportunity was not provided, Commission reliance on that post-hearing information, other than as an "admission against interest" to show the *unreasonableness* of PNM's use of its 2010 revenues to determine its RCT limits in this case, would violate the rights of REIA and other parties to procedural due process.

In Rebuttal, Ms. Bothwell offered a number of reasons why the Commission should not use projected revenues based on PNM's current rates to determine its RCT limits that have no merit and are unpersuasive. She argued first that, in the Stipulation proposed in Case No. 10-0037-UT, CCAE, WRA and REIA agreed to PNM's use of its prior calendar year revenues to "avoid speculation and contentiousness" for determining its RCT limits.⁶⁷ That is true. In that case unlike this one, however, PNM did not receive and implement a *substantial* rate increase shortly after filed its Revised 2010 Plan and well before the hearing and closure of the record there.

In fact, in its *initial* 2010 Plan filed on July 1, 2009, PNM did not use the "rates" in effect in the prior calendar year for its RCT calculations. Ms. Bothwell testified that

⁶⁷ Bothwell Reb., p. 10.

PNM used “the rates in effect as of July 1, 2009,” that included “fuel adjustments for the prior year [2008] such that further fuel adjustments were not necessary.”⁶⁸

Ms. Bothwell argued further that utility reliance on prior year’s revenues to calculate its RCT limit was a method “used in the rulemaking in Case No. 08-00198-UT” and “included in Staff’s proposal for the new rulemaking in 11-00218-UT.”⁶⁹ As noted earlier, however, the Commission never issued a final order approving that in Case No. 08-00198-UT. Nor has the Commission issued a final order in Case No. 11-00218-UT adopting Staff’s proposed revisions to Rule 572.11, which don’t address the sort of *substantial* rate change before closure of the record in a utility plan case at issue here.

Ms. Bothwell also argues (without citation) that “SPS used the projected revenues in the year prior to the new procurement and decreased the total revenues by those received from the large customers covered by Rule 572.10.C,” that “[n]either SPS nor EPE included projected rate increases,” and that “[t]heir projected revenues were based on current rates and projected sales.”⁷⁰ As noted earlier, however, REIA (and other interveners and Staff) do not argue that PNM should be required to use any “projected rate increases” to determine its RCT limits in this case. Rather, they argue that PNM should be required to use its *projected revenues* based on its *current rates*, clearly established by the Commission prior to the hearing, and projected sales volumes to determine those RCT limits *in this case*. Moreover, the projected sales volumes REIA contends PNM should use to calculate those limits are exactly the same as the “Projected Retail Sales (MWh)” PNM used in its Plan to determine its RPS (before any “Large

⁶⁸ REIA Ex. 5 (Bothwell Dir., Case No. 09-260-UT, p. 14 & Ex. CDB-6); *see also* Rule 572.10.D.

⁶⁹ Bothwell Reb., p. 10.

⁷⁰ *Id.*

Customer” or RCT “Adjustments”), which take into account sales *reductions projected by PNM* due to “approved and *projected* energy efficiency” programs.⁷¹

Ms. Bothwell presented no evidence that either SPS or EPE relied on their prior year’s revenues to determine RCT limits in any *similar* case where *they* received a substantial rate increase shortly after filing a renewables plan. As noted earlier, the plain language in Rule 572.11.B provides no basis for PNM to exclude revenues from its large, Rule 572.10.C customers from its RCT revenue projections.

Ms. Bothwell also argues that “using existing rates for all customers” to calculate its RCT limits “is consistent with the approach required for the large customer adjustment to the RPS” as provided in Rule 572.10.D.⁷² Again, PNM’s 2010 revenues are not based on PNM’s “existing” rates. Moreover, that argument conveniently ignores the language in Rule 572.10.D stating: “*In determining the amount of the reduction specified in Subsection C of this section, a public utility shall assume that electric rates in effect on the day of the procurement plan filing will be in effect for the year during which the procurement reduction will apply.*” (Emphasis added).

Subsection C of Rule 572 literally applies only to the large customer RPS reduction referenced in subsection D. That “rate” assumption for that adjustment makes sense. Otherwise, IOUs would be required (and allowed) to reduce their annual RPS using large customer adjustments based on revenues those customer won’t pay due to the special renewables rate increase protection they enjoy in the REA (§ 62-16-4.A(2)). That would be nonsensical.

⁷¹ 2012 Plan (PNM Ex. 1), p. 7, Table 1 Corrected, note 1 (emphasis added); Bothwell Dir., p. 10.

⁷² Bothwell Reb. (PNM Ex. 8), p. 11.

In contrast, the language in Rule 572.11.B addressing determination of the RCT limit, quoted earlier, contains no similar prior year “rates” assumption. Had the Commission intended to include such an assumption there, it easily could and would have done so. There is no inconsistency between that language and the assumption in Rule 572.D that the Commission needs to reconcile, as Ms. Bothwell suggests, by using former rather than *current* PNM rates to calculate its 2012 and 2013 RCT limits.

Ms. Bothwell’s further argument that it would be unreasonable to require PNM to calculate its RCT limits in this case based on the higher rates PNM was granted shortly after it filed its 2012 Plan because that would “create a ‘moving target’”⁷³ also is unpersuasive. REIA is not recommending that, as a general matter, PNM be required to calculate its RCT limits based on speculative rates that have not been approved by the Commission, and therefore can not reasonably be projected by PNM, prior to the closure of the record in this (or any other renewable plan) case. And given the various “updated” SIP participation information and other data, *and* the “interim” SIP extension proposal addressed earlier (effectively amending its initial 2012 Plan) that PNM did not present until it filed its Rebuttal Testimony on September 30, 2011, PNM is not in a position to make a persuasive “moving target” argument in this case.

Though not offered by PNM as legal expert, Ms. Bothwell also argues that “PNM’s energy efficiency rider is not a charge for electricity...but only recovers the costs associated with offering energy efficiency programs to PNM’s customers,” so PNM should not be required to include revenues from that rider in its calculation of its RCT limits, likening that to “a tax on top of an existing tax.”⁷⁴ Again, however, the plain

⁷³ *Id.*, p. 11.

⁷⁴ *Id.*, p. 12.

language in Rule 572.11.B does not make the *legal* distinction or suggest the meaning Ms. Bothwell pours into it.

The Efficient Use of Energy Act authorizes IOUs to recover the costs of approved energy efficiency and load management programs for their customers. That Act describes those programs as “cost-effective resources that are an essential component of the balanced resource portfolio that public utilities must achieve to provide affordable and reliable energy to public utility customers.”⁷⁵ PNM likewise describes those demand-side programs in its 2011 IRP as “resources” that provide peak demand “savings” and reductions for the Company’s and its customers’ benefit.⁷⁶ For these reasons, this “tax on top of tax” analogy by Ms. Bothwell, who also claimed no expertise about tax matters at the hearing,⁷⁷ is neither legally supported nor otherwise justified.

B. PNM’s Unreasonable Abandonment of the “Levelized” Method it Used to Justify the Reasonableness of its *Owned* Solar Resources to Calculate the Annual “Net Revenue Requirements” Costs of Procurements from those Resources.

As shown on REIA Exhibits 9 and 10 and addressed by Mr. Sadewic,⁷⁸ in Case No. 10-00037-UT, PNM very clearly used a “levelized” cost method to both justify the reasonableness of the cost of the utility-owned 22 MW of PV and Solar Demo projects it proposed in its Revised 2010 Plan (compared to procuring equivalent solar energy and RECs through a PPA) to the Commission *and* calculate the projected “procurement costs” of those solar resources for applying the RCT in 2010-2011. The Commission’s

⁷⁵ NMSA, § 62-17-2.

⁷⁶ NMIPP Exs. 2 and 3.

⁷⁷ 10/25 Tr. at 135-136 (Bothwell).

⁷⁸ Sadewic Dir., pp. 31-34 and Ex. RS-6.

Final Order in that case approved those PNM-owned solar projects without clearly addressing the reasonableness of that RCT cost calculation method.⁷⁹

In this case, PNM abandoned that levelized method and switched to a non-levelized cost method to calculate the cost of its procurements from those PNM-owned solar resources in 2012 and 2013. As shown on Ms. Bothwell's Exhibit CDB-4, the non-levelized calculation of the "net revenue requirements" costs of those procurements (\$7.8 million in 2012 and \$7.1 million in 2013) to acquire approximately 10.7% and 10.5% of the total RECs procured by PNM's 2012 Plan in 2012 and 2013 account for substantial portions (approximately 40.4% and 36.4%) of the total cost of PNM's proposed 2012 Plan in those years, respectively.

PNM Discovery "Exhibit REIA 1-6" (in REIA Exhibit 3) shows that, if PNM used a levelized method to calculate the "net revenue requirements" of those PNM-owned solar resources (excluding *any* avoided capacity costs), that reduces the total cost of PNM's 2012 Plan by \$874,337 in 2012 (\$19,342,981-\$18,468,644) when the RCT is 2.25%, and by \$212,366 in 2013 (\$19,510,879 -\$19,258,513) when the RCT *increases* to 2.50%.⁸⁰ That Exhibit also shows that, if PNM used that levelized calculation of the cost of procurements from its *owned* solar resources *and* PNM's higher projected revenue "approximations" of \$926.4 million in 2012 and \$936 million in 2013 based on its *current* rates, the costs of PNM's proposed 2012 Plan are *well below* (1.99% in 2012 and 2.06% in 2013) the 2.25% and 2.50% RCT limits in both of those years.

⁷⁹ Case No. 10-00037-UT, *Final Order Partially Adopting Recommended Decision; But see, id.*, pp. 20-22 (after relying on Ms. Bothwell's justification of these utility-owned solar resources and addressing RCT claims by the AG and others, stating that, in approving the first 22 MW proposed under the PNM-Owned Utility-Sited Solar Program we shall expect the same assumptions described as pertaining to that approach to apply to the 22 MW phase of this project the same as they would for the total 45 MW.®).

⁸⁰ See also REIA Ex. 3 (last page); 10/25 Tr. at 130-133 (Bothwell).

Ms. Bothwell acknowledged that PNM advocated adoption of the levelized cost method to calculate renewables costs as part of the “consensus” proposal in Case No. 08-198-UT, and also used that method in its 2010 Plans (Case Nos. 09-260-UT and 10-00037-UT) to justify the reasonableness of the cost of its “self-build” solar resources.⁸¹ She testified that PNM “returned to its original method based on actual costs and actual avoided costs” to calculate the costs of those PNM-owned resources because the Commission “chose not to adopt” that method in Case No. 08-198-UT, and because “in recent cases several stakeholders, including those that represent ratepayer interests, have supported an RCT methodology that reflects the actual rate impact to customers....”⁸²

Ms. Bothwell acknowledged that she is not a rate expert, and that the “net revenue requirements” calculations for the solar resources shown on her RCT Exhibit CDB-4 were provided by other PNM personnel who did not testify in this case.⁸³ Mr. Sadewic explained that, even if the Commission accepts Ms. Bothwell’s argument that Rule 572.11 should be interpreted as a customer “rate impact” limit “*without consideration for rate cycles* using actual costs and avoided costs,” there are a number of additional reasons why PNM’s abandonment of the levelized method to calculate the revenue requirements of its *owned* solar resources in this case is not reasonably justified.⁸⁴

Even *before* any settlement discussions began or any settlement was proposed in PNM’s 2010 Plan cases (Nos. 09-260-UT and 10-00037-UT), Ronald Darnell, PNM’s Vice-President, Regulatory Affairs, testified under oath that it “is important that net

⁸¹ Bothwell Reb., p. 8; *See also* REIA Ex. 8 (“PNM Attachment A” to 12/1/09 Revised NOPR in Case No. 09-198-UT); Contrary to Ms. Bothwell’s Rebuttal Testimony, REIA Ex. 4 shows that she also relied on the levelized cost method in Case No. 08-221-UT to address PNM’s concerns regarding various DG program proposals for its 2009 Plan “in relation to” the RCT. *See also* REIA Ex. 1 (Darnell Reb., p. 10).

⁸² Bothwell Reb., p. 8. As noted earlier, the only “choice” the Commission made in Case No. 08-198-UT was to close that docket without taking any action on the “consensus” proposal there.

⁸³ 10/25 Tr. at 116-120 (Bothwell).

⁸⁴ Sadewic Dir., pp. 28-38.

levelized cost be used in calculating the RCT” because “PNM strongly believes that it is in our customers’ best interest that PNM own at least some portion of the renewable resources required to meet RPS compliance in 2011 and beyond,” and “[i]t is unlikely that new renewable generation owned by PNM would pass the RCT if the RCT calculation was based on a method other than the levelized method.”⁸⁵ Mr. Darnell subsequently testified in Case No. 10-00037-UT that the levelized approach is consistent with the “‘life cycle cost analysis on a net present value basis’ that the Commission is required to consider in establishing the RCT under Rule 572.11.B(4)” and “with the methodology employed by other New Mexico utilities in their procurement plans.”⁸⁶ He also testified there that use of the levelized method to calculate the annual costs of its renewables procurements is particularly appropriate to address “the problem of the high initial cost of adding owned resources to rate base, which could cause a proposed resource to be rejected for non-compliance with the RCT in a single year, even though the cost in all future years might be below the RCT,” thus disadvantaging “self-build projects...compared to a long-term PPA.”⁸⁷

Ms. Bothwell testified similarly in Case No. 10-00037-UT, adding:

The levelized method using life cycle cost per 17.9.572.11 NMAC...provides the *truest view of the total cost and total impact and benefit* of the renewable resources and of the total renewable portfolio standard. If the RCT is calculated *on a piecemeal basis*, it will encourage projects that are less efficient overall but which squeeze in under an earlier year RCT calculation *and will not properly recognize the system costs and benefits of a renewable project over its useful life.*⁸⁸

This sworn testimony by Mr. Darnell and Ms. Bothwell (and PNM’s support of the levelized method in Case No. 08-198-UT) shows quite clearly that, *apart from any*

⁸⁵ REIA Ex. 6 (Darnell Dir., Case No. 09-260-UT, pp. 9-10).

⁸⁶ REIA Ex. 1 (Darnell Reb., Case No. 10-00037-UT, p. 10); *see also* Sadewic Dir., Ex. RS-9.

⁸⁷ REIA Ex. 1 (Darnell Reb., Case No. 10-00037-UT, pp. 10-11).

⁸⁸ REIA Ex. 10 (Bothwell Reb., Case No. 10-00037-UT, p. 2) (emphasis added).

settlement concerning the details of PNM's Revised 2010 Plan in Case No. 10-00037-UT, PNM understood that the levelized method *is* the appropriate method for the Commission to use to calculate the annual costs and customer impacts of its renewables procurements *based on the RCT provisions in the REA and Rule 572, and even from a customer benefit viewpoint*. It also shows quite clearly that PNM explicitly asked the Commission to rely on that RCT calculation method to justify the reasonableness of the 22 MW of PV and Solar Demo resources proposed in that Plan.⁸⁹

The levelized cost method is appropriate and consistent with the RCT criteria in the REA (§ 62-16-4.C (3) and (4)) and Rule 572.11.B(3) and (4) because they *require* that the Commission consider *both* “the impact of the cost for renewable energy on retail customer rates” *and* “their life cycle cost on a net present value basis” when establishing the RCT. That method *also* is consistent with the “net revenue requirements” method PNM uses to calculate the impact of the costs of its 2012 Plan on its customers’ rates.

The Commission’s RCT percentages apply on a calendar year basis. It is undisputed, however, that as provided in paragraph 27 of the Stipulation approved by the Commission in Case No. 10-00086-UT addressed by Mr. Sadewic,⁹⁰ PNM will not be able to even *begin* recovering most of the 2012 costs calculated in Ms. Bothwell’s Exhibit CDB-4 (i.e., except for NMWEC procurement costs recovered by PNM’s FPPCAC) from customers until July 1, 2012. Thus, most of those costs will not “impact” PNM’s customers in 2012. Instead, their “actual” annual bill impacts on customers will be deferred beyond 2012 pursuant to that Stipulation and as authorized in Rule 572.12.

⁸⁹ See also *id.*, pp. 10-11 (justifying inclusion of PNM’s Solar Demo Project in its RCT calculation on the grounds that it intended to use it for RPS compliance and, based on the levelized cost method, its \$237,880 RCT impact in 2011 would be only 0.03%); Compare Ms. Bothwell’s Ex. CDB-4 (calculating the *non-levelized* costs of that project to be \$521,434 in 2012 and \$490,569 in 2013).

⁹⁰ Sadewic Dir., pp. 29-31.

Use of the levelized cost method is particularly appropriate to calculate the annual revenue requirements of PNM's procurements from its 22 MW of *utility-owned* PV and 0.5 MW Solar Demo projects for RCT purposes when the Commission considers how PNM is allowed to effectively levelize the 30% federal investment tax credit ("ITC") it received when it invested in those resources for ratemaking purposes.⁹¹ When calculating the 2012 and 2013 "revenue requirements" (bill) impacts of its procurements from *those* solar resources, PNM does *not* include (i.e., pass through) the full amount of that tax benefit to its customers. Instead, relying on provisions in the Internal Revenue Code (IRC)⁹² and prior Commission approval of tax "normalization" (rather than "flow through") treatment of such federal tax credits for ratemaking purposes, PNM amortizes those ITC benefits on a straight-line basis over the projected 30-year useful lives of those *utility-owned* resources.⁹³ As a result, only 1/30th of those ITC benefits to the Company is included in PNM's calculation of the *annual* revenue requirements associated with those resources shown in the RCT analysis on Ms. Bothwell's Exhibit CDB-4 and will be passed on annually to customers when PNM is authorized to recover those revenue requirements beginning in July 2012 (through the "Renewables Rider" agreed to in the Stipulation approved by the Commission in Case, No. 10-00086-UT).⁹⁴

In other words, based on this tax "normalization" ratemaking treatment, PNM will be allowed to defer passing along most of the federal ITC benefits associated with its investments in these two utility-owned solar resources to its customers until *after* the

⁹¹ See Case No. 08-260-UT, Direct Testimony of Ron Darnell, PNM Ex. 1, pp. 32-33 (explaining that Congress' expansion in 2008 of the federal ITC to utility-owned renewable generation was one of the principal PNM considerations in selecting these utility-owned solar resources instead of procuring similar amounts of solar energy through PPAs with developers).

⁹² IRC § 50(d)(1), referencing § 46(f) of 1990 IRC (use of investment credits by "regulated companies").

⁹³ See, e.g., 10/25 Tr. at 122-125, 134-136 (Bothwell); 10/21 Tr. at 44-56 (Blank).

⁹⁴ 10/25 Tr. at 137-138 (Bothwell); 10/21 Tr. at 53-56 (Blank); see also Sadewic Dir., pp. 29-30.

2012 “Plan year” and 2013 addressed in its RCT calculations in this case. The amount of those up-front ITC benefits to PNM and its shareholders is significant.

In Case No. 10-00037-UT, PNM informed the Commission that the estimated “capital costs” of the initial 22 MW of utility-owned PV and 0.5 MW PV Demo projects it proposed there were \$101.7 million and \$6 million, respectively.⁹⁵ At 30% (even if not applicable to 100% of its Solar Demo project “capital costs”), the up-front federal ITC benefit to PNM on those investments is \$26 million or more. That tax benefit *alone* is substantially greater than the *total* \$17.9 million and \$19.9 million RCT *limits* calculated by Ms. Bothwell on her Exhibit CDB-4 for 2012 and 2013, respectively, and even the higher RCT limits calculated by REIA and other parties in this case. Use of the levelized cost method to calculate PNM’s RCT limits also is consistent with PNM’s ability to use accelerated tax depreciation benefits for its investments in these *owned* solar resources faster and sooner than it depreciates those investments, on a straight-line basis, over the useful lives of those resources for ratemaking purposes.⁹⁶

In contrast, PNM’s non-levelized method of calculating the “net revenue requirements” of its *owned* solar resources is a non-synchronized and biased RCT approach that attempts to take unreasonable advantage of this levelization of benefits in the ratemaking process in order to *reduce* its RPS in the REA and its minimum diversity obligations and evade compliance with the Commission’s 2011 solar diversity variance requirement in Case No. 10-373-UT. PNM’s use of that non-levelized cost method is, in fact, exactly the sort of “piecemeal” approach to calculating the RCT that, as quoted earlier, Ms. Bothwell testified in Case No. 10-00037-UT is inappropriate. As such, it not

⁹⁵ Case No. 10-00037-UT, Darnell Dir. (PNM Ex. 1), Ex. RND-3.

⁹⁶ See Stipulation, ¶¶ 25.f and 27.f, approved by *Final Order* in Case No. 10-00086-UT.

only is inconsistent with the legal criteria in § 62-16-4.C(4) and Rule 572.11.B(4), but also with the requirement in 572.8 that Rule 572 “be liberally construed to carry out its intended purposes” of implementing the REA, as provided in Rule 572.6.

C. PNM’s Unreasonable Exclusion of the Avoided Capacity Cost Benefits of its Owned Solar and NMWEC Wind PPA Resources from its “Net Revenue Requirements” Calculations.

PNM’s calculations also unreasonably overstate the annual costs of its proposed 2012 Plan for applying the RCT by failing to include any avoided capacity cost benefits from its owned 22 MW of PV and Solar Demo resources *or* its wind PPA with NMWEC.⁹⁷ Mr. Sadewic and witnesses for NMIPP, Staff, CCAE/WRA and SFC testified that this omission is unreasonable because (i) as PNM testified in Case No. 10-00037-UT, those solar and wind resources provide avoided capacity cost benefits to PNM and its customers that the Commission is required by the REA (§ 62-16-4.C(4)) and Rule 572.11.B(4) to “take into account” in establishing the RCT and (ii) in accord with those laws, EPE and SPS include avoided capacity costs in *their* calculations of the annual costs of *their* solar procurements when applying the RCT to *their* renewables plans.⁹⁸

Ms. Bothwell acknowledged the latter fact.⁹⁹ She offers, however, various reasons why she believes exclusion of avoided capacity costs from her calculations of the annual costs of PNM’s owned solar NMWEC resources is reasonable.¹⁰⁰ None of those

⁹⁷ Bothwell Dir., Ex. CDB-4, Tables 4&5. The “Procurement Costs/Savings” calculations in parenthetical on those Tables reflect only avoided fuel and system loss benefits. *Id.*, pp. 13-15.

⁹⁸ Sadewic Dir., pp. 32-38 and Ex. RS-9; Beach Dir. (NMIPP Ex. 1), pp. 8-10, 12-14, 17-20, 22-23; Lamberson Dir. (Staff Ex. 1), pp.14-16, 19; Curl Dir. (CCAEx. 1), pp. 4-5; O’Hare Dir., pp. 11-14.

⁹⁹ Bothwell Reb., p. 39 (Ex. CDB-1R, “Avoided Capacity” Comparison); *see also* Sadewic Dir., Ex. RS-9 (RCT calculation by EPE in Case No. 11-263-UT showing EPE uses a “2011 Levelized Avoided Cost per MWh of Combustion Turbine” of \$165.224 “based on EPRI TAG calculation” and a March 2011 EIA forecast of natural gas prices).

¹⁰⁰ Bothwell Reb., pp. 6-7, 9-10, 15-24.

reasons has merit. They are all either inconsistent with applicable law or contradicted by the record here and established ratemaking principles.

The provisions in § 62-16-4.C and Rule 572.11.B do not authorize the Commission or IOUs to apply the RCT “from a ratepayer perspective” in a manner that fails to consider the life cycle benefits of renewables until a future year when a utility announces it is not installing additional non-renewable generation resources *that year* to satisfy its peak system demands *that year*. Those laws direct the Commission to consider the life-cycle benefits of proposed renewable resources at the time they are proposed beginning *when those resources are placed in service*.

In fact, in Case Nos. 09-260-UT and 10-00037-UT where PNM proposed acquisition of its 22 MW of PV and Solar Demo resources, Ms. Bothwell testified that the levelized avoided capacity cost benefit of those solar resources was \$30.41 per MWh “based upon EPRI TAG data for a 1x1 combined cycle facility *customized to PNM and New Mexico conditions*” and included “transmission integration costs *and begins at the in-service date of the new renewable resource*.”¹⁰¹ Responding to criticism of that calculation by the AG’s witness in that case, Ms. Bothwell testified:

...the RCT calculation is a comparison between utility business with and without compliance with the RPS based on life-cycle costs. The RCT calculation considers the total cost of the renewable resource over the life of the resource as is done in the IRP process. My Direct Testimony page 14, lines 11-15, discuss [sic] how PNM determined avoided capacity, which was the result of negotiations of the parties in the Renewables Stipulation and is not inconsistent with the rule amendments proposed in Commission Case No. 08-00198-UT and the methodologies used and approved for the other utilities in New Mexico.¹⁰²

¹⁰¹ REIA Ex. 9 (Bothwell Dir., p. 14 and Ex. CDB-6, Case No. 09-260-UT) (emphasis added).

¹⁰² REIA Ex. 10 (Bothwell Reb, pp. 8-9, Case No. 10-00037-UT).

The *signatories* to the Stipulation in that case did not “customize” the EPRI TAG data for a 1x1 combined cycle facility “to PNM and New Mexico conditions.” How could they have? *PNM did.*

Ms. Bothwell’s arguments that her exclusion of avoided capacity costs from these RCT calculations is “based on best available data,” and that they are “hypothetical future benefits” because “there are no non-renewable projects that are being deferred or eliminated” in 2012 or 2013 “based on renewable procurements” are contradicted by the record. Ms. Bothwell acknowledged at the hearing that, pursuant to a stipulation approved in Case No. 08-305-UT, PNM is required to maintain a “firm reserve margin” (i.e., exclusive of its “non-firm, intermittent resources”) of 13% of its “base scenario” (mid-load) forecast of peak demand on its system.¹⁰³ As shown on PNM’s most recent Load and Resources (“L&R”) Table in its July 2011 IRP, however, PNM’s firm reserve margin will fall *below 13% (12.6%) in 2013.*¹⁰⁴ Ms. Bothwell acknowledged this at the hearing, agreeing that PNM is counting on peak capacity (“contribution”) from its “non-firm” renewable resources shown on that Table, which include its 22 MW of PV, to meet its “minimum reserve capacity margin as set by this Commission in 2013.”¹⁰⁵ As shown on that L&R Table (and stated in PNM’s 2011 IRP, p. 107), “Solar PV systems are expected to contribute 55% of the installed capacity to meet the reserve margin.”¹⁰⁶

Ms. Bothwell acknowledged that, to meet its firm reserve margin in 2012 and 2013, PNM also is relying on investments it made *prior to those years* to install the non-

¹⁰³ 10/25 Tr. at 92-94, 101 (Bothwell).

¹⁰⁴ NMIPP Ex. 3.

¹⁰⁵ 10/25 Tr. at 100-102, 104-106 (Bothwell); *see also* 10/24 Tr. at 43, 45-46 (Beach).

¹⁰⁶ The 12 MW of peak capacity in 2012 and 2013 from “Future Renewable Additions-Approved” shown on NMIPP Ex. 3 is 55% of the 22 MW of PNM-owned PV approved by the Commission in Case No. 10-00037-UT. That L&R Table also shows PNM expects that its projected peak system demands will be reduced each year by 55% of the installed capacity from its “Customer Sited PV.” 10/25 Tr. at 94-95, 103.

renewable owned generation resources identified on that L&R Table.¹⁰⁷ She also testified that it typically takes about two years from initiation of planning to an in-service date for PNM to actually install an additional gas-fired peaking plant.¹⁰⁸

As Mr. Beach explained, from a utility planning (or ratepayer) perspective, PNM cannot wait until the year in which it needs a new non-renewable resource to meet the projected peak demand on its system to begin planning for that additional resource or spending funds to do so.¹⁰⁹ For these reasons, Ms. Bothwell's argument that neither PNM nor its customers receive any avoided capacity cost benefit in 2012 or 2013 from PNM's installation, in 2010 and 2011, of its owned 22 MW of PV and Solar Demo resources is not only unjustified from an economics point of view, but also contradicted by the realities of reasonable public utility resource planning.

Ms. Bothwell's "actual benefit" argument also is inconsistent with the very ratemaking process PNM relies on to calculate the "net revenue requirements" costs of renewables when applying the RCT. That process includes elements, such as "construction work in progress" and "allowance for funds used during construction," that allow IOUs to include in their rates costs for new generation plant incurred *before* it is placed in service, thus recognizing that customers receives the benefits of that plant *when it is placed in service*. And, as the Commission is aware, to *benefit* its customers, PNM based the rates in the proposed Stipulation approved (in part) by the Commission in PNM's most recent general rate case (No. 10-00086-UT) on *future* "Test Period" cost and revenue data that allowed PNM to recover "budgeted" future costs it had not yet incurred.

¹⁰⁷ 10/25 Tr. at 106-110; *see also id.*, at 92 (Bothwell) (Ms. Bothwell is not an economist).

¹⁰⁸ *Id.*, at 110-112; *see also id.* at 113-114 (Bothwell).

¹⁰⁹ 10/24 Tr. at 36-37 (Beach).

Using *PNM-specific data*, Mr. Beach, NMIPP’s expert, calculated that, excluding DG avoided cost benefits due to the Stipulation in Case No. 10-00086-UT), the avoided capacity-related benefits from PNM’s owned solar resources are \$0.0319 per kWh for generation and \$0.0463 per kWh for transmission in 2012 which, when applied to the 52,431 MWh of owned solar procurements projected on Ms. Bothwell’s Ex. CDB-4, reduce PNM’s proposed 2102 Plan costs by \$4.10 million.¹¹⁰ He testified that PNM’s procurements of bundled wind from NMWEC provides PNM with an *additional* avoided capacity benefit (with no avoided transmission capacity cost) of \$98.76 per kW-year, reducing those Plan costs by an additional \$0.99 million in 2012.¹¹¹ Using a different approach, Staff calculated PNM’s total avoided costs from its renewables procurements to be \$165.22 per MWh, resulting in \$21.7 million and \$23.4 million reductions of PNM’s proposed Plan costs in 2012 and 2013, respectively.¹¹²

PNM did not provide any different avoided capacity cost calculations in this case. As noted earlier, however, Ms. Bothwell testified in Case No. 10-00037-UT that its proposed owned solar resources would provide it with a levelized avoided cost benefit “customized to PNM and New Mexico conditions” of \$30.41 per MWh beginning at their “in-service date.”¹¹³ Moreover, in response to discovery here, Ms. Bothwell explained that “using the methodology and assumptions” in that case for 2011-2012 “would result in the same levelized costs” for its owned solar resources in 2012-2013.¹¹⁴

¹¹⁰ Beach Dir. (NMIPP Ex. 1), pp. 19-20 and Table 2; *see also id.*, at 8-10.

¹¹¹ *Id.*

¹¹² Lamberson Dir. (Staff Ex. 1), pp. 15-16.

¹¹³ *See also* Sadewic Dir., pp. 32-33 and Ex. RS-6.

¹¹⁴ REIA Ex. 3 (Supplemental Response to REIA 1-4).

PNM projects that its 22 MW of PV and Solar Demo resources will provide it with 52,311 MWh/RECs in 2012 and 52,043 MWh/RECs in 2013.¹¹⁵ Applying the levelized PNM-“customized” avoided capacity cost credit of \$30.41 per MWh to those MWh projections reduces the annual costs of those resources (and PNM’s proposed 2012 Plan) using PNM’s “net revenue requirements” approach by \$1.59 million in 2012 and \$1.58 million in 2012. These *additional* avoided capacity cost reductions to PNM’s calculations of the costs of its proposed 2012 Plan show further why the Commission should reject PNM’s claimed RCT reductions to its RPS and solar diversity requirements and its “alternate” proposals (on Bothwell Exhibit CDB-4) to satisfy its RPS and solar diversity shortfalls in 2012 and 2013 with single-year purchases of unbundled wind and solar RECs that will not add any renewable energy to its renewables portfolio.

CONCLUSION

For the foregoing reasons, REIA urges the Commission to (i) reject PNM’s proposed 2012 Plan, its RCT-based RPS reductions and solar diversity requirement compliance claims and its “alternate” proposals to satisfy its RPS and solar diversity requirements, (ii) approve REIA’s proposed extension of the existing SIP for systems 100 kW and smaller, and (iii) adopt the other REIA positions set forth in this brief.

Respectfully submitted,

Bruce C. Throne
Attorney at Law
1440-B South St. Francis Dr.
Santa Fe, NM 87505
Telephone: (505) 989-4345
Fax: (505) 820-2560
E-mail: bthroneatty@newmexico.com
Attorney for REIA

¹¹⁵ Bothwell Dir., Ex. CDB-4 Corrected, Tables 4&5.