BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

PUBLIC SERVICE COMPANY OF NEW MEXICO'S NOTICE OF FILING OF "RENEWABLE ENERGY PORTFOLIO PROCUREMENT PLAN FOR 2012"

PUBLIC SERVICE COMPANY OF NEW MEXICO, Petitioner.

Case No. 11-00265-UT

DIRECT TESTIMONY AND EXHIBITS OF R. THOMAS BEACH ON BEHALF OF THE NEW MEXICO INDEPENDENT POWER PRODUCERS

October 3, 2011
DIRECT TESTIMONY OF
R. THOMAS BEACH
NMPRC UTILITY CASE NO. 11-00265-UT

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INTRODUCTION

Q. Please state for the record your name, position, and business address.
A. My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q. Please describe your experience and qualifications.
A. My experience and qualifications are described in the attached curriculum vitae ("CV"), which is attached to this testimony as Exhibit RTB-1.

Q. Have you previously submitted testimony before this Commission?
A. Yes, I have. In Public Service of New Mexico’s ("PNM") recent general rate case (Docket No. 10-00086-UT), I served testimony in support of the Stipulation that PNM and other parties filed in that case on February 3, 2011. My testimony was prepared on behalf of the Interstate Renewable Energy Council ("IREC"), and addressed the provision of the Stipulation whereby PNM withdrew the riders that it had proposed for new customers who install distributed generation ("DG"), including solar photovoltaic ("PV") systems.

I also have testified on numerous occasions before state regulatory commissions in California, Nevada, Oregon, and Colorado. My CV includes a current list of the testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities.

Q. On whose behalf are you testifying today?
A. I am appearing on behalf of the New Mexico Independent Power Producers ("NMIPP"). NMIPP is an association that advocates for the development of new utility-scale independent power production in New Mexico through open
wholesale competition in order to deliver clean, reliable, and cost-competitive electricity while stimulating economic development in New Mexico.

Q. What is the interest of NMIPP in this proceeding?
A. NMIPP is concerned with PNM’s assertion that it is not required to purchase additional renewable energy in 2012 because the costs for its existing purchases of renewable generation will exceed its Reasonable Cost Threshold (“RCT”).

Q. What is the purpose of this testimony?
A. This testimony provides an analysis of PNM’s proposed RCT calculations in its Revised 2012 Renewable Energy Portfolio (“REP”) Plan filing. I also comment on the Commission Staff’s RCT proposals in PNM’s Revised 2010 and Revised 2011 REP Plan cases and on Western Resource Advocates’ (“WRA”) initial proposal for a revised RCT calculation in the Commission’s Rulemaking Docket #11-00218-UT, which would apply to all of the electric utilities in New Mexico. I also review the RCT calculation that El Paso Electric (“EPE”) recently filed in its REP Plan case, Docket No. 11-00263-UT.

Based on this review, I propose, on behalf of NMIPP, an approach to the RCT calculation that modifies the PNM proposal in two key ways that will make PNM’s approach more consistent both with the statutory basis for the RCT and with the EPE approach. If approved by the Commission, this approach would help to standardize the RCT methodology in New Mexico. To reduce the need for annual litigation, and to improve stability in the renewable energy market, NMIPP urges the Commission to consider adopting this methodology for the remainder of the REP for PNM, rather than just for one year.
II. SUMMARY OF RECOMMENDATIONS

Q. Please summarize NMIPP's recommendations concerning the application of the RCT to PNM in 2012 and subsequent years.

A. This testimony recommends that an RCT calculation for PNM that is most consistent with the underlying statute and with EPE's approach.

NMIPP’s recommended RCT would be:

the sum of the following costs:
1. Forecast, Renewable Portfolio Standard ("RPS") costs in upcoming calendar year. The RPS costs will include costs for both bundled and REC purchases;
2. Integration costs;
3. Incremental billing system costs, beyond those now included in rates, that PNM has shown to be necessary and prudent to implement PNM’s Commission-approved REP Plan; and
4. WREGIS costs for tracking and verifying RPS purchases.

less these avoided costs from bundled RPS purchases (but not from REC or DG purchases):
5. Avoided fuel costs;
6. Avoided line losses; and
7. Avoided capacity costs.

The resulting net costs for renewables would be divided by the best available forecast of revenues in the future year for which the RCT is being established (i.e. 2012), in order to determine the rate impact for that year. When applied to PNM’s 2012 costs for existing renewables, this approach shows that PNM’s costs for existing renewables in 2012 will be 1.65%, below the 2.25% RCT limit for that year. The Commission also may want to consider a variation on the above approach in which both the costs of utility-owned renewables, and their avoided cost benefits, are levelized, so that all of the RPS costs and benefits in the numerator of the RCT calculation are expressed on a levelized basis. Levelizing the costs of PNM’s utility-owned renewables results in a modest reduction in those costs, and increases the avoided cost benefits of these resources.
The testimony of PNM’s witness Ms. Cynthia D. Bothwell includes data on the
costs of the purchases that PNM could make in 2012 but for the RCT constraint.
Based on these costs, plus accounting for avoided capacity costs and using
forecasted 2012 revenues in the denominator of the RCT calculation, PNM will
be able to meet its full 10% RPS obligation in 2012. PNM can meet its full RPS
obligation in 2012 using both wind RECs and diversity resource (i.e. solar)
additions, while remaining below the RCT limit that NMIPP recommends.

III. BACKGROUND

Q. Please describe the statute governing the RCT calculation in New Mexico.

A. The Renewable Energy Act ("REA") states that the Commission should “take into
account” the following in setting the RCT:

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;
3. the impact of the cost for renewable energy on overall retail customer
   rates;
4. the overall diversity, reliability, availability, dispatch flexibility, cost per
   kilowatt-hour and life-cycle cost 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.

Obviously, this is a broad set of considerations, and the statute does not prescribe
precisely how the RCT calculation is to be performed. As a result, the
Commission appears to have considerable leeway in adopting an approach to
calculate the RCT, although of course it also must create a record showing that it
has appropriately considered each of the factors listed above when establishing a
reasonable method for calculating the annual costs of a utility’s renewable energy
procurement. To some extent these factors can be difficult to reconcile: for

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NMSA 1978, § 62-16-4(C)(1) to (5).
example, the third criteria calls for the Commission to consider the rate impacts of
renewable energy purchases, while the fourth factor includes consideration of the
net present value ("NPV") of the lifecycle costs of renewable resources. The rate
impacts of renewable resources in the near term are not the same as the lifecycle
costs for these resources; thus, a resource with relatively high near-term rate
impacts may have a lower lifecycle cost than other resources with more modest
immediate rate impacts.

Q. Has the Commission provided any detailed direction on the RCT
calculation?
A. No, it has not. Instead, the Commission has approved a variety of approaches to
the RCT calculation in prior renewable energy portfolio plan filings. As I will
discuss further below, the approach to the RCT calculation that NMIPP
recommends in this case uses elements, such as avoided capacity costs, from the
approach which El Paso Electric has used in Docket No. 11-00263-UT and in its
prior REP plan filings.

IV. REVIEW OF PROPOSED RCT CALCULATION METHODOLOGIES

Q. What proposals are you aware of for setting the RCT for PNM in 2012?
A. It is my understanding that three parties have advanced proposals for setting the
RCT for PNM in 2012: PNM itself, Commission staff, and Western Resource
Advocates ("WRA"). I will discuss each of these proposals in turn below, then
review the EPE approach filed in Docket No. 11-00263-UT.
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A. PNM

Q: Please describe PNM's approach to the RCT calculation in its revised 2011
REP Plan.

A: PNM proposes to compare its RCT limit to the costs of its annual renewable
energy procurement, which PNM asserts are:

the sum of the following costs:

a. Forecasted RPS costs in 2012 and 2013, including costs for both bundled
and REC purchases,
b. Integration costs,
c. Billing system costs, and
d. WREGIS costs for tracking and verifying RPS purchases
less
e. The avoided fuel costs and avoided line losses from bundled RPS
purchases (but not from REC purchases).

The utility then would divide these net costs by actual PNM revenues in 2010 to
calculate RPS costs as a percentage of 2010 utility revenues. The utility would
compare this percentage to its RCT percentage in 2012 (2.25%) to determine if its
renewable procurement exceeds this RCT limit.

Q: What net RPS costs for its existing renewable contracts does PNM forecast in
2012, and will these costs be within what PNM believes to be its RCT limit?

A: The testimony of PNM witness Ms. Bothwell projects $20.3 million in net RPS
costs in 2012 (2.55% of 2010 revenues) from PNM's existing renewable
resources, or $41 per MWh of renewable power. Using PNM's approach, the
RCT limit in 2012 would be 2.25% of 2010 revenues of $797.3 million, or $17.9
million. Because this is less than the costs of PNM's existing renewable contracts,
the utility proposes no incremental RPS purchases in 2012.

Q: What about 2013?

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2 Exhibit CDB-4, Table 4.
A: In 2013, the RCT limit will increase to 2.5%. PNM expects its 2013 costs to be slightly above 2.5% of 2010 revenues, but anticipates that 2011 revenues will be greater than in 2010, thus allowing additional RPS purchases in 2013 and subsequent years. In other words, PNM would use actual 2011 revenues as the denominator of the RCT percentage calculation in 2013. Thus, PNM states that it expects to resume procurement of new renewables in 2013.

Q: What problems do you see with PNM’s RCT calculation?

A: I see three basic issues:

First, the purpose of the RCT is clearly to place a limit on the costs for renewable energy as a percentage of overall customer rates. This is expressed clearly in the third factor listed in the REA. Accordingly, as applied to PNM’s renewable purchases in 2012, the purpose of the RCT should be to place a limit on RPS costs in 2012 as a percentage of 2012 rates. Thus, the first issue that stands out in PNM’s proposed RCT is its use of actual 2010 revenues in the denominator of the calculation of the RCT percentages for 2012 and 2013. Although the use of a recorded number has the benefit of being known, actual 2010 revenues really have little to do with what PNM’s costs or revenues will be in 2012. It is clear today, and was clear when PNM made its revised REP Plan filing in July, that PNM’s revenues in 2012 will be significantly higher than in 2010, as a result of the large rate increase was in the final stages of approval at the Commission in July, and that now has received final approval in Docket No. 10-00086-UT. Furthermore, recorded revenues can be affected, both up or down, by past economic or weather conditions that may not be typical of the future or of the average conditions used in forward-looking projections. As a result, PNM’s use of historical revenues is not the best estimate of “the impact of the cost for renewable energy on overall retail customer rates,” the third factor that the REA requires to be considered in setting the RCT.

3 Exh. CDB-4, Table 5 and Exh. CDB-5.
Second, it is my understanding that, in its integrated resource plans, PNM selects new resources, both utility-owned and independently-owned, based on the levelized cost to the ratepayer over the life cycle of the resource. The fourth factor in the REA states that such levelized costs should be considered in setting the RCT. However, the utility uses the revenue requirements for its renewable resources in the RCT calculation, which represents the current rate impact of these resources (the third factor in the REA). For utility-owned renewable resources whose costs are recovered under traditional rate-base accounting, this results in costs for utility-owned renewables that are, in the early years of their operation, higher than their levelized costs. This problem does not exist for renewables acquired through third-party PPAs, because the contract prices for such resources typically are levelized over the term of the REC contract (either 12 or 20 years). This difference can be seen in Ms. Bothwell’s Exhibit CDB-5 by comparing the costs over time between the 22 MW of PNM-owned solar resources (not levelized) and the costs of solar DG resources acquired through REC PPAs (levelized).

Third, the only benefits that PNM accounts for explicitly are the avoided fuel and avoided line loss costs for non-REC purchases. However, the REA states that the RCT calculation should consider the contribution of renewables to system reliability (the fourth factor in the REA). Renewable resources contribute to system reliability because they provide a certain amount of dependable generating capacity that is available to serve peak demands and that PNM counts in its resource plans. As a result, renewable power sources avoid the need for PNM to build additional conventional generating capacity, thus supplying important avoided capacity benefits that reduce ratepayer costs. The capacity-related costs that can be avoided by adding more renewable energy to the grid include:

- capital costs associated with the avoided generating assets;
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- capital costs for transmission interconnection and system upgrades
  specifically assigned to the avoided generating assets;
- transmission and distribution costs that are avoided because solar can be
  sited closer to loads than other types of generation, and
- fixed operating and maintenance costs of the avoided generating assets,
  which the utility would have to incur whether or not the unit operated..

Utilities across the country have conducted studies to assess the value of avoided
capacity costs from renewable resources. For example, the graph below, from a
2009 study prepared for Arizona Public Service (“APS”) by R.W. Beck, shows
that each kilowatt-hour of solar added to the APS grid provides between 0.81 to
5.89 cents per kWh of capacity cost savings to the utility.4

![Solar DE Value Buildup Graph]

PNM’s own resource plans count at least a portion of the installed capacity of the
renewable generation on its system toward its capacity needs, indicating that the

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utility believes that these resources provide capacity benefits. However, PNM’s RCT calculation fails to account for these avoided capacity costs.

B. Commission Staff

Q: Please describe the NMPRC Staff’s proposed approach to the RCT calculation.

A: The Commission staff would base the RCT on incremental RPS costs, that is, the costs for new RPS purchases in any given year. Thus, the RCT would be:

Forecasted RPS costs for new RPS purchases (including new REC purchases) in the procurement plan year, based on the revenue requirement or rate impact of such purchases. Specifically excluded are RPS costs included under prior year RCTs or already included or approved for inclusion in rates, less The avoided fuel costs from these purchases.

These net costs are then divided by “all customers’ aggregated overall annual electric charges for the most recent calendar year prior to a filing,” which for PNM would be actual PNM revenues in 2010. Even though the staff proposal would consider only incremental RPS costs, the staff would continue to compare this much more limited set of costs to 2.25% of PNM’s overall electric charges, with this percentage growing at 0.25% per year.

Q: What problems have you identified with the staff’s approach?

A: The staff’s proposal focuses only on the costs of new, incremental purchases of renewables in the test year. Absent the RCT, PNM states that, in 2012, it could meet its full 10% RPS requirement by purchasing 315,296 MWh of incremental wind RECs for $2.7 million ($8.60 per MWh), or a similar quantity of mixed renewables.

PNM’s 2008 Resource Plan (at page 37) values PNM’s long-term contract for wind at 10 MW of capacity. PNM assumes that solar PV resources will produce at 65% of nameplate at the time of the system peak (2008 Resource Plan, a:74).
solar and wind RECs for $4.2 million ($13.00 per MWh). These costs for incremental RPS purchases are just 0.29% and 0.45% of PNM’s expected 2012 revenues, far below 2.25%. Thus, it is clear that, under staff’s RCT proposal, PNM’s 2012 costs for incremental renewables would be far below the 2.25% RCT percentage. I expect that PNM could meet its full RPS obligation without ever approaching the staff’s RCT limit in any year. Conversely, if the utility’s new renewable purchases in every year hit the staff’s limit, and thus increased its revenue requirement by 2% to 3% each year compared to the prior year, PNM’s rates would escalate very quickly, even if the utility’s remaining costs simply increased with inflation. Such a result seems contrary to the intent of the RCT statute. Finally, like PNM, staff fails to consider the important avoided capacity benefits of renewable resources.

C. WRA

Q: Please describe WRA’s position on the RCT calculation.
A: In the PRC Rulemaking Docket #11-218-UT, WRA has proposed that the Commission identify technology-specific cost limits for each type of renewable energy resource, and establish the RCT limits using these specific costs. These cost limits would be for bundled RPS purchases. WRA has proposed the following limits:

a. $160/MWh for small-scale solar (< 100 kW)
b. $110/MWh for large-scale solar (> 100 kW)
c. $50/MWh for wind
d. $70/MWh for other technologies.

WRA proposes that the RCT for REC-only purchases would be set at 2% of 2011 total jurisdictional revenues and escalate to 3% as the current rule provides. WRA notes that the RCT for a REC-only purchase is simpler and can be subject to a rate-impact test because, by definition, a stand-alone REC represents the additional impact to rates associated with REA compliance. This revenue percentage would be reduced by a percentage equal to the ratio of unbundled

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RECs to total REC procurement, for utilities making both REC-only and bundled
REC purchases.

Q: **Please critique WRA’s proposal.**
A: WRA’s proposal is difficult to analyze, as WRA did not provide precise details
for the calculations it envisions. For example, we assume, but are not sure, that
the WRA cost caps are meant to be before any adjustment for avoided fuel or
avoided capacity savings. The costs of most of PNM’s existing wind resources
fall below WRA’s $50 per MWh wind cap, but most of the utility’s existing solar
RECs are more expensive than WRA’s caps. Further, based on Table B in Ms.
Bothwell’s testimony, the results of PNM’s 2011 RPS RFP show wind
($60/MWh), solar ($130/MWh), geothermal ($120/MWh), and biomass
($120/MWh) costs that are higher than WRA’s caps ($50/MWh for wind, $110
for large solar, and $70/MWh for the other technologies).

Thus, even if WRA’s proposal is adopted, it is unclear if PNM could purchase
new renewables in 2012 at those caps (much less at 20% less than the caps, which
WRA suggests will be possible). WRA states that its proposed caps are
“reflective of our estimates of the current market price of these resources.” The
differences between WRA’s market estimates and PNM’s RFP results show the
primary difficulty with WRA’s proposal: in my view, WRA’s proposal will result
in disagreements over what are reasonable market prices. Such disputes can be as
complex and as difficult to resolve as the issues raised by the rate impact
approaches used by PNM and staff.

D. **El Paso Electric**

Q: **Please discuss the RCT calculation that EPE proposed in the REP Plan that
it has filed in Docket No. 11-00263-UT.**
A: EPE filed its most recent RCT calculation for 2012-2013 in conjunction with its
REP Plan. EPE starts with the entire cost of the unbundled RECs and the net cost
of the bundled renewable resources (i.e. both energy and RECs) that it expects to purchase in those years. EPE calculates the net cost of its bundled renewable resources as the levelized cost of the renewable resource less the levelized, “all-in” costs of the fossil resource that the renewables replace. EPE includes in those avoided costs not just the avoided fuel-related cost for the non-renewable technology, but also the associated non-fuel fixed and variable costs and the levelized capacity costs of that fossil resource. Unlike PNM, EPE’s avoided fuel costs are based on the levelized, long-term costs to fuel the avoided fossil resource. For baseload renewables, EPE uses a combined-cycle plant with a levelized, all-in cost of $107.64 per MWh. For peaking renewables including solar, EPE assumes that the avoided fossil resource is a gas turbine peaker with an all-in cost of $165.22 per MWh. Finally, EPE assumes that a solar resource will contribute 85% of its nameplate capacity to the system peak.  

Thus, EPE’s approach to the RCT calculation can be described as follows:  

- the sum of the following costs:  
  a. Forecasted RPS costs in 2012 and 2013, including costs for both bundled and REC purchases,  
  b. WREGIS costs for tracking and verifying RPS purchases  
     less, for bundled RPS purchases,  
  c. The levelized fuel costs from the avoided fossil resource,  
  d. Non-fuel fixed and variable costs of the avoided fossil resource, and  
  e. Levelized capacity costs of the avoided fossil resource.

To calculate the RCT percentage for 2012-2013, EPE divides these RPS costs by an estimate of its revenues in 2012-2013. EPE’s estimated revenues for 2012-2013 are based on an assumption that base rates in effect on the day of the 2011 plan filing will be in effect for 2012 and 2013.  

I would characterize EPE’s approach as emphasizing the long-term rate impact of its renewable purchases, because EPE employs the long-term levelized costs of its renewable purchases.
renewable contracts less the long-term levelized costs of the fossil alternatives to those purchases.

EPE states that this approach is the same methodology that it used in its last two procurement proceedings, NMPRC Case Nos. 09-00259-UT and 10-00200-UT, and that its methodology was developed from workshops in NMPRC Case No. 08-00198-UT, Inquiry into a Standard Methodology for Determining Renewable Energy Costs for the Purpose of 17.9.572.11 NMAC. ⁸

V. RECOMMENDED APPROACH FOR CALCULATING THE RCT

Please describe the approach to calculating the RCT that you believe to be most consistent with the REA.

My understanding of the intent of the RCT provisions of the REA is that they ask the Commission to establish a reasonable limit on the rate impact in a given year of a utility’s purchases of renewable power. I have discussed above a number of issues and problems with PNM’s suggested approach laid out in this docket. The best means to address these issues and to meet the statutory goal, in my opinion, is to modify PNM’s proposal, drawing from methodologies already under use by other utilities in the state. Without the following two modifications, PNM’s approach falls short of complying with the guidance set forth in the REA rules. The changes that I recommend are:

- Use a forecast of revenues for the year to which the RCT applies.
- Include avoided capacity costs in the RCT calculation.

The Commission also may want to express both the costs of utility-owned renewables, and the costs of the fossil resources that they avoid, on a levelized basis, as EPE has done. The EPE approach emphasizes the long-term rate impacts of renewables, and would be consistent with the fact that PNM pays a

⁸ Ibid., at pp. 7-8.
constant, levelized price for the renewable resources that it purchases through
power purchase agreements or REC purchase contracts.

Q: Please discuss your first recommended modification.
A: The third factor that the REA requires to be considered in setting the RCT is "the
impact of the cost for renewable energy on overall retail customer rates." As I
have discussed above, PNM's use of historical revenues as the measure of the
level of retail rates in the future year for which the RCT is being established is not
the best estimate of "overall retail customer rates."

As an alternative to using recorded revenues, I recommend that the utility use its
best available forecast of revenues in the future year for which the RCT is being
established. This use of forecasted revenues should not be viewed as requiring
the use of "speculative" projections. Indeed, the use of recorded revenues in the
denominator of the calculation of the RCT percentage is the only element of that
calculation which does not use forecasted quantities. The quantities and costs of
renewable purchases in 2012 (i.e. the numerator of the calculation of the RCT
percentage), as well as the overall RPS requirements for 2012, are all based on
forecasts for 2012. Furthermore, PNM makes regular forecasts of its future
revenues, for a variety of planning and regulatory purposes, including periodic
presentations to investors and rating agencies. These forecasts obviously include
assumptions about future rates that may differ from what the Commission
ultimately approves. This circumstance is no different than the assumptions about
future sales or costs which are part of PNM's RCT calculation - these
assumptions also can differ from Commission-adopted quantities. The
Commission can make clear that its adoption of a forecast of 2012 revenues is for
the limited purpose of setting the RCT, and has no precedential value in any other
context.
Q: What do you believe to be the best available forecast of PNM's 2012 revenues?

A: At the time of PNM's filing of its 2012 REP Plan, the best available forecast of PNM's 2012 revenues would have been the PNM General Rate Case (GRC) Stipulation's proposal for a Phase 2 revenue requirement of $900.8 million (based on 2010 volumes). Since PNM filed its RCT proposal, the Commission has reduced the Stipulation's rate increase by about $13 million per year in its final order in the PNM GRC. Based on that final order in the PNM GRC, and adjusting for PNM's forecast of 2012 volumes, PNM has confirmed that a reasonable estimate of 2012 revenues is $926.4 million. This is $129.1 million higher than actual 2010 revenues of $797.3 million, and thus would increase the 2.25% RCT for 2012 from $17.9 million to $20.8 million. This forward-looking forecast is a much better estimate of 2012 revenues than using recorded data that is two years old (i.e. $926.4 million is a much better forecast of 2012 revenues than is $797.3 million).

PNM forecasts its costs for renewable generation in 2012 in the numerator of the RCT calculation, and we are confident that the utility can provide an up-to-date forecast of its revenues in 2012 for use in the denominator. This approach of using the best available estimate of test year 2012 revenues will provide the most accurate estimate of the impact of renewable costs on rates in the test year, which is the fundamental intent of the RCT calculation.

Another way to look at this issue is to examine Ms. Bothwell's figure (Exh. CDB-5) showing PNM's own estimate of the RCT limit through 2030 and the costs of PNM's existing renewables. Using a forecast of 2012 revenues instead of actual 2010 revenues would shift the curve for the RCT limit two years to the left –

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9 See Stipulation in Case No. 10-00086-UT, filed February 3, 2011, Exhibit 1, at p. 2 of 5.
10 PNM "Response to the Email of Mr. Throne Dated September 22, 2011," included in Exhibit RTB-2.
apparently providing at least a small amount of “headroom” for additional RPS purchases in all years including 2012.\textsuperscript{11}

Q: Why should the RCT calculation consider avoided capacity costs?
A: The RCT calculation must look broadly at the avoided cost benefits of RPS power. The only benefits that PNM accounts for explicitly are the avoided fuel and avoided line loss costs for non-REC purchases. However, the REA states that the RCT calculation should consider the contribution of renewables to system reliability (Factor #4). In this regard, bundled renewable power provides avoided capacity benefits. Electric systems are reliable because they have adequate generating capacity to meet peak needs. Renewable resources can provide such capacity, although intermittent wind and solar resources typically are credited with less firm capacity than their nameplate capacity. As a result, renewables reduce ratepayer costs not just by displacing fuel use and reducing line losses, but also because the utility does not have to procure another source of capacity to ensure a reliable electric system.

Q: Has PNM recognized that renewable generation provides capacity benefits to its system?
A: Yes. PNM’s testimony in its recent GRC acknowledged that new DG customers provide benefits in terms of savings in fuel, purchased power, and line losses, and can avoid investment-related costs for generation and transmission capacity.\textsuperscript{12}

Q: Have you quantified these capacity-related benefits?
A: Yes. PNM’s avoided summer capacity costs associated with its energy efficiency and demand response programs are $98.76 per kW-yr in 2012, as stated in Appendix A of PNM’s 2009 annual report on its energy efficiency programs. In the GRC, PNM used the same 2009 avoided costs to calculate the avoided energy

\textsuperscript{11} Assuming $20.3 million in 2012 RPS costs as shown in Ms. Bothwell’s Exhibit CDB-4, the RCT percentage based on 2012 revenues of $926.4 million would be 2.19\% = $20.3 / $926.4.

\textsuperscript{12} Direct Testimony of James A. Mayhew in Docket No. 10-00086-UT, at page 92, lines 22-23.
costs associated with DG, with an adjustment for the drop in natural gas costs since the 2009 avoided costs were determined. It is important for the Commission to treat energy efficiency, demand response, and renewable/distributed generation consistently in the calculation of avoided cost benefits. Thus, if PNM’s projected avoided summer capacity-related costs for energy efficiency and demand response are $98.76 per kW-year in 2012, the same value should be used to assess the avoided capacity benefits of new renewable generation.

Q. What about avoided transmission costs?
A. The marginal cost study that PNM performed for its recent GRC includes a summer marginal transmission cost of $143.35 per kW-year, based on expected marginal transmission investments during this rate case cycle.

Q. You have noted that wind and solar resources are intermittent, and will not provide 100% of their nameplate capacity on a reliable basis during a utility’s system peak. In valuing the capacity-related benefits of wind and solar in your analysis of their capacity benefits, do you recommend discounting the rated capacity of wind and solar units?
A. Yes. I used the same assumptions for the operation of wind and solar that PNM employed in its most recent Integrated Resource Plan: 65% of the rated capacity of solar DG is available at the time of the system peak, and the solar DG operates with a 23% capacity factor. In my opinion, the use of 65% of rated capacity as the capacity value of solar resources is consistent with other studies of actual

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As stated in Appendix A to PNM’s 2009 EE Annual Report, these avoided costs are the same as those approved in Case No. 08-00204-UT. This appendix is included in Exhibit RTB-3.

PNM Marginal Cost Study, Sheet Transmission-I, line 5, from Docket No. 10-00086-UT. This marginal cost is based on adding 50.8 MW of peak transmission capacity from 2011-2014. This sheet is included in Exhibit RTB-3.

operating experience with solar DG. For wind, PNM's 2008 resource plan (at page 37) values PNM's long-term contract for wind at 10 MW of capacity.

Q. Using these assumptions, what are the annual capacity-related benefits that should be included in the 2012 RCT calculation?

A. I assume that solar DG can avoid 65% of generation and transmission avoided capacity costs, and that a 1 kW solar DG system produces 2,015 kWh per year (i.e. a 23% capacity factor). With these assumptions, the resulting per unit capacity benefits are $0.0319 per kWh for generation and $0.0463 per kWh for transmission. In dollar terms, when applied to the 52,431 MWh of bundled, utility-owned solar generation in 2012, these capacity benefits reduce PNM's RPS costs by $4.10 million.

Bundled wind also has a generation capacity value – PNM's 10 MW of effective capacity from the New Mexico Wind Energy Center is worth $0.99 million per year at PNM's 2012 avoided capacity cost of $98.76 per kW-year. As wind is more remotely located, we do not assume that wind avoids costs for transmission capacity.

The total avoided capacity benefits of PNM's bundled RPS purchases in 2012 are thus $5.09 million, $4.1 million from solar and $0.99 million from wind.

PNM assigns no additional costs or benefits to its purchases of DG RECs in 2012. In the GRC PNM proposed DG riders to collect what it believed to be the costs of DG for non-participating ratepayers. My GRC testimony for IREC in Docket No. 10-00086-UT opposed this proposal, and showed that DG provides greater

16 The California Public Utilities Commission's 2009 evaluation report on the California Solar Initiative reports that installed PV systems have shown outputs of 59% of rated capacity at the time of the system peak. See http://www.cpuc.ca.gov/PUC/energy/Solar/eval09.htm, at pages 5-5 to 5-6.

17 $98.76/kW-yr x 0.65 / 2015 kWh/kW-yr = $0.0319/kWh.

18 $144.35/kW-yr x 0.65 / 2015 kWh/kW-yr = $0.0463/kWh.

19 $4.10 million = ($31.90 + $46.30 per MWh) x 52,431 MWh.
benefits to PNM’s ratepayers than the reduced bills that result from DG
installations using net metering. In other words, DG produces benefits for non-
participants. IREC showed that these benefits were 6 c/kWh, or $60/MWh, for
small customers with DG, and more for larger end users who install DG.\textsuperscript{20}
However, in the GRC Stipulation the parties settled on PNM’s withdrawal of the
gD rider proposal. PNM’s assumption here of no cost or benefit from DG for
non-participants is consistent with the parties’ agreement in the GRC Stipulation.

\textbf{Q:} Does the EPE approach to the RCT calculation consider the avoided capacity
benefits of its purchases of bundled renewables?

\textbf{A:} Yes, it does. EPE uses the “all-in” costs of a combined-cycle and a combustion
turbine as the measures of the long-term costs that are avoided by its purchases of
bundled renewables. These “all-in” avoided costs include both avoided energy
and capacity costs.

\textbf{Q:} Please discuss the issue of whether the costs of utility-owned renewables used
in the RCT Calculation should be levelized.

\textbf{A:} There are good arguments that the costs of utility-owned renewable resources
should be expressed on a levelized basis. This would reflect the long-term rate
impact of these resources (REA Factor #3), while also recognizing the life-cycle
and net present value (i.e. levelized) cost of all renewable resources on a
comparable basis (REA Factor #4). PNM’s approach of using the traditional
revenue requirements for utility-owned renewable generation relies entirely on
REA Factor #3 with no consideration of REA Factor #4 (levelized, life-cycle
costs), except perhaps for the fact that PNM procured the utility-owned
renewables because, in PNM’s view, they were less expensive on a levelized basis
than third-party PPAs. Further, using levelized costs for utility-owned renewables
would be consistent with the costs of PNM’s purchased renewable resources,
which typically are already levelized.

\textsuperscript{20} IREC GRC Testimony, at 25 and Exhibits RTB-2 and RTB-3.
However, the use of levelized costs for utility-owned resources also presents difficulties. The levelized costs of these resources differ from the actual revenue requirements for these resources that will be included in PNM’s rates in 2012, so the use of levelized costs would move the RCT calculation away from a measure of short-term rate impacts in 2012. In addition, for consistency the use of these levelized costs would have to be carried forward into the RCT calculation in subsequent years.

**Q:** What would be the impact on the RCT calculation if the costs of utility-owned renewable resources were levelized?

**A:** Based on PNM’s response to a data request from REIA, Table 1 shows that the levelized costs of PNM’s utility-owned renewables in 2012 is $0.47 million lower than the costs using traditional ratemaking.\(^2\)

**Table 1:** Costs of PNM’s Utility-owned Renewables: Traditional vs. Levelized

<table>
<thead>
<tr>
<th>Utility-owned Resource</th>
<th>2012 Volumes</th>
<th>Traditional</th>
<th>Levelized</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MWh</td>
<td>$/MWh</td>
<td>$000</td>
</tr>
<tr>
<td>Algodones-Aztec</td>
<td>120</td>
<td>521.83</td>
<td>567</td>
</tr>
<tr>
<td>Solar w/ Batteries</td>
<td>1,086</td>
<td>183.95</td>
<td>9,239</td>
</tr>
<tr>
<td>PNM 22 MW PV</td>
<td>50,225</td>
<td>149.28</td>
<td>9,806</td>
</tr>
<tr>
<td>Total / Average</td>
<td>52,311</td>
<td>149.28</td>
<td>9,806</td>
</tr>
</tbody>
</table>

Sources: Exhibit CDB-4, PNM Response to REIA Data Request 1-4

**Q:** What is your recommendation on the levelization issue?

**A:** As discussed below, the two other adjustments that I propose to the RCT calculation for PNM result in PNM’s 2012 RPS costs for its existing renewables falling well below the RCT threshold, with enough “headroom” for PNM to fully comply with its RPS obligations in 2012. As a result, there is no need for the Commission to consider the levelization issue at this time.

\(^2\) PNM provided the levelized costs of its utility-owned renewables in response to REIA Data Request 1-4 (PNM Exhibit REIA 1-4). This response is included in Exhibit RTB-2.
Q: Please summarize your recommended RCT calculation for PNM.

A: An RCT calculation for PNM that is consistent with the REA should determine PNM’s net costs for renewable generation in 2012 using the following formula:

PNM’s net costs for renewable generation in the year for which the RCT is being set would be:

*the sum of the following costs:*

1. Forecasted RPS costs in the upcoming calendar year. The RPS costs will include costs for both bundled and REC purchases;
2. Integration costs;
3. Incremental billing system costs, beyond those now included in rates, that PNM has shown to be necessary and prudent to implement PNM’s Commission-approved REP Plan; and
4. WREGIS costs for tracking and verifying RPS purchases.

*less these avoided costs from bundled RPS purchases (but not from REC or DG purchases):*

5. Avoided fuel costs;
6. Avoided line losses; and
7. Avoided capacity costs, which should be consistent with those used to evaluate energy efficiency and demand response programs.

Table 2 shows NMIPP’s recommended RCT calculation for PNM for 2012 based on the above approach. To determine the RCT percentage for existing resources, the total net cost from Table 2 of $15.3 million is divided by the best available forecast of PNM’s 2012 revenues, $926.4 million, as of the date when the utility made the filing to set the RCT. The result is that PNM’s costs for its existing renewables in 2012 will be 1.65% of its overall retail rates, well below the RCT threshold.

Q: Can PNM purchase additional renewables in 2012 adequate to meet its RPS obligations, at a cost that is less than the RCT limit that you have recommended?
Yes, it can. The lower portion of Ms. Bothwell’s Table 4 in Exhibit CDB-4 shows the costs of the additional purchases that PNM could make in 2012 to fill out a 10% RPS portfolio in 2012, either with new wind RECs alone or with diversity resource additions that include both solar and wind RECs. Incorporating these into my Table 2, the lower portion of the table shows that PNM should be able to meet its full 10% RPS obligation in 2012 using both wind and solar RECs (i.e. full diversity resource additions) at a cost that is 2.09% of its anticipated 2012 revenues. This would be within the RCT limit for 2012 of 2.25%.

If the RCT calculation were to use levelized costs for PNM’s utility-owned renewables and to offset renewable costs with levelized avoided costs, what would the result be?

Table 3 shows the results of this calculation. I have taken the levelized costs of the PNM-owned renewables from PNM’s data response to REIA, and used EPE’s levelized costs for the avoided fossil resource (a combustion turbine) that PNM’s bundled solar resources will displace. For PNM’s wind purchases, I used a 10-year levelized avoided capacity cost from Appendix A of PNM’s 2009 annual report on its energy efficiency programs. The calculations in Table 3 show that the use of levelized costs – in other words, a long-term rate impact perspective – provides even more “headroom” below the RCT for additional purchases of renewables in 2012 than the approach that is NMIPP’s primary recommendation.

Does this conclude your direct testimony?

Yes, it does.
### Table 2: NMIPP Proposed RCT Calculation for 2012

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
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<td>Wind</td>
<td>Existing Resources</td>
<td>355,000 $</td>
<td>27.25 $</td>
<td>(22.53) $</td>
<td>4.72 $</td>
<td>1,674,900 $</td>
<td>71.7%</td>
</tr>
<tr>
<td>Distributed Generation</td>
<td>Small PV RECs</td>
<td>11,408 $</td>
<td>34.33 $</td>
<td>3.76 $</td>
<td>47.09 $</td>
<td>537,203 $</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Small PV RECs</td>
<td>10,606 $</td>
<td>130.00 $</td>
<td>11.25 $</td>
<td>141.25 $</td>
<td>1,498,098 $</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Large PV RECs</td>
<td>19,539 $</td>
<td>150.00 $</td>
<td>12.98 $</td>
<td>162.98 $</td>
<td>3,184,466 $</td>
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</tr>
<tr>
<td></td>
<td>SIP DG @ 0.14</td>
<td>1,231 $</td>
<td>140.00 $</td>
<td>12.11 $</td>
<td>152.11 $</td>
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</tr>
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<td>141.25 $</td>
<td>329,536 $</td>
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</tr>
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<td>6,725 $</td>
<td>120.00 $</td>
<td>10.38 $</td>
<td>130.38 $</td>
<td>537,203 $</td>
<td></td>
</tr>
<tr>
<td></td>
<td>SIP DG @ 0.11</td>
<td>9,592 $</td>
<td>110.00 $</td>
<td>9.52 $</td>
<td>119.52 $</td>
<td>1,146,436 $</td>
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</tr>
<tr>
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<td>SIP DG @ 0.10</td>
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<td>8.66 $</td>
<td>108.66 $</td>
<td>623,382 $</td>
<td></td>
</tr>
<tr>
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<td>6,883 $</td>
<td>90.00 $</td>
<td>7.79 $</td>
<td>97.79 $</td>
<td>673,086 $</td>
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</tr>
<tr>
<td></td>
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<td>3,237 $</td>
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<td>5.20 $</td>
<td>65.20 $</td>
<td>95,388 $</td>
<td></td>
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<tr>
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<td>54.34 $</td>
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<td>Total Distributed Generation</td>
<td>82,262 $</td>
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<td>9,661,786 $</td>
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<td>574.62 $</td>
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<td>(119.88) $</td>
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<td>PNM Owned PV 22 MW</td>
<td>51,225 $</td>
<td>183.95 $</td>
<td>(119.88) $</td>
<td>64.07 $</td>
<td>3,281,986 $</td>
<td></td>
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<tr>
<td></td>
<td>Total Solar</td>
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<td>3,776,407 $</td>
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<td>10.88 $</td>
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<td>600 $</td>
<td>20.00 $</td>
<td>1.74 $</td>
<td>21.74 $</td>
<td>13,044 $</td>
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<td>4,660 $</td>
<td>20.00 $</td>
<td>1.74 $</td>
<td>21.74 $</td>
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<td>$</td>
<td>$</td>
<td>$</td>
<td>95,392 $</td>
<td>0.8%</td>
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<td>Total Proposed</td>
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<td></td>
<td>210,179 $</td>
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<td>WREGIS Annual Fee</td>
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<td>$</td>
<td>1,500 $</td>
<td>0.0%</td>
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<td></td>
<td>Total Annual Resources</td>
<td>494,973 $</td>
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<td>15,323,272 $</td>
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<td>Blended REC Cost</td>
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<td>RCT Limitation</td>
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<td></td>
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<td></td>
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</tbody>
</table>

#### Full RPS Resource Additions

1. **RPS with Wind Resource Additions**

| 2012 Revenues | 315,296 $ | 7.91 $ | 0.70 $ | 8.61 $ | 2,714,699 $ | 1.95% |
| Portfolio Impact | $ | 18,037,971 |

2. **RPS with Diversity Resource Additions**

| Total Portfolio | 810,268 $ | 2.09% |               |               |               |               |          |

Crossborder Energy
Table 3: PNM RCT Calculation for 2012 Using Levelized Costs

<table>
<thead>
<tr>
<th>2012 Existing Resources</th>
<th>Procurement Costs/Savings</th>
<th>2012 Net Rev Req's</th>
<th>2012 Net % RECS % Cost</th>
</tr>
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<tbody>
<tr>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind - NMWEC</td>
<td>355,000 $</td>
<td>27.25 $</td>
<td>(22.82) $</td>
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<tr>
<td>Distributed Generation</td>
<td></td>
<td></td>
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<tr>
<td>Small PV RECs</td>
<td>11,406 $</td>
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<td>3.76 $</td>
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<td>Small PV RECs</td>
<td>10,606 $</td>
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<td>11.25 $</td>
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<td>Large PV RECs</td>
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<td>12.98 $</td>
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<tr>
<td>SIP DG @ 0.14</td>
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<td>140.00 $</td>
<td>12.11 $</td>
</tr>
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<td>SIP DG @ 0.13</td>
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<td>100.00 $</td>
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<td>Solar</td>
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<tr>
<td>Algodones Aztec @31</td>
<td>120 $</td>
<td>574.62 $</td>
<td>(140.44) $</td>
</tr>
<tr>
<td>Solar Demo with Batteries</td>
<td>1,086 $</td>
<td>474.37 $</td>
<td>(140.44) $</td>
</tr>
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<td>PNM Owned PV 22 MW</td>
<td>51,225 $</td>
<td>174.31 $</td>
<td>(140.44) $</td>
</tr>
<tr>
<td>Total Solar</td>
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<td>$ 2,149,698</td>
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</tr>
<tr>
<td>Biogas (RECs)</td>
<td>0 $</td>
<td>10.00 $</td>
<td>0.88 $</td>
</tr>
<tr>
<td>Resources &amp; Costs Proposed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Santa Fe Hydro</td>
<td>600 $</td>
<td>20.00 $</td>
<td>1.74 $</td>
</tr>
<tr>
<td>SIP DG 2012 $0.02</td>
<td>4,680 $</td>
<td>20.00 $</td>
<td>1.74 $</td>
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<td>Billing System Upgrade</td>
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<td>$ 95,392</td>
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<tr>
<td>Total Proposed</td>
<td>5,280 $</td>
<td></td>
<td>$ 210,179</td>
</tr>
<tr>
<td>WREGIS Annual Fee</td>
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<td>$ 1,500</td>
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<td>Total Annual Resources</td>
<td>494,973 $</td>
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<td>$ 13,594,963</td>
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<td>Blended REC Cost</td>
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<tr>
<td>2012 Revenues</td>
<td></td>
<td></td>
<td>$ 926,400,000</td>
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<tr>
<td>Portfolio RCT Impact</td>
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<td>1.47%</td>
</tr>
<tr>
<td>RCT (Impacted)</td>
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<table>
<thead>
<tr>
<th>Full RPS Resource Additions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. RPS with Wind Resource Additions</td>
</tr>
<tr>
<td>Wind REC Purchases</td>
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<tr>
<td>Total Portfolio</td>
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<tr>
<td>Portfolio RCT Impact</td>
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<td>2. RPS with Diversity Resource Additions</td>
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<td>Solar RECs</td>
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<tr>
<td>Wind RECs</td>
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<td>SIP DG 2012 @ 0.038</td>
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<tr>
<td>Total Portfolio</td>
</tr>
<tr>
<td>Portfolio RCT Impact</td>
</tr>
</tbody>
</table>
Exhibit RTB-1

Qualifications and Experience of R. Thomas Beach
Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- **Renewable Energy Issues**: extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- **Restructuring the Natural Gas and Electric Industries**: consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- **Energy Markets**: studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- **Qualifying Facility Issues**: consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- **Pricing Policy in Regulated Industries**: consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.
EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

   - Competitive and environmental benefits of new natural gas pipeline capacity to California.

   - Natural gas procurement policy; gas cost forecasting.

   - Brokering of interstate pipeline capacity.

   - Natural gas procurement policy; gas cost forecasting; brokerage fees.

   - Firm and interruptible rates for noncore natural gas users

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   - Brokering of interstate pipeline capacity; intrastate transportation policies.

7. Prepared Direct Testimony on Behalf of the Canadian Producer Group (A. 90-08-029/Phase II — April 17, 1991)
   - Natural gas brokerage and transport fees.

   - Natural gas parity rates for cogenerators and solar powerplants.

   - Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.


   - Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.

    - Natural gas procurement policy; prudence of past gas purchases.

12. a. Prepared Direct Testimony on Behalf of the California Cogeneration Council (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the California Cogeneration Council (I. 86-06-005/Phase II — July 2, 1992)

    - Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.

13. Prepared Direct Testimony on Behalf of the California Cogeneration Council (A. 92-10-017 — February 19, 1993)
    - Performance-based ratemaking for electric utilities.
   • Natural gas transportation service for wholesale customers.

15. a. Prepared Direct Testimony on Behalf of the Canadian Association of Petroleum Producers (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the Canadian Association of Petroleum Producers (A. 92-12-043/A. 93-03-038 — July 8, 1993)
   • Natural gas pipeline rate design issues.

   • Utility overcharges for natural gas service; cogeneration parity issues.

17. Prepared Direct Testimony on Behalf of the City of Vernon (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)
   • Natural gas rate design for wholesale customers; retail competition issues.

   • Natural gas rate design issues; rate parity for solar power plants.

   • Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.

   • Recovery of above-market nuclear plant costs under electric restructuring.

   • Natural gas rate design; unbundled mainline transportation rates.
   
   - \textit{Incremental Energy Rates; air quality compliance costs.}

23. 
   
   - \textit{Natural gas market dynamics; gas pipeline rate design.}

   
   - \textit{Natural gas rate design: parity rates for cogenerators.}

25. Prepared Direct Testimony on Behalf of the \textit{City of Vernon} (A. 96-10-038 — August 6, 1997)
   
   - \textit{Impacts of a major utility merger on competition in natural gas and electric markets.}

26. 
   a. Prepared Direct Testimony on Behalf of the \textit{Electricity Generation Coalition} (A. 97-03-002 — December 18, 1997)
   
   - \textit{Natural gas rate design for gas-fired electric generators.}

   
   - \textit{Natural gas service to Baja, California, Mexico.}

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\textit{Crossborder Energy}

- Natural gas cost allocation and rate design for gas-fired electric generators.


- Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.


- Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the California Cogeneration Council (A. 00-04-002 — September 1, 2000).
b. Prepared Direct Testimony on behalf of Southern Energy California (A. 00-04-002 — September 1, 2000).

- Natural gas cost allocation and rate design for gas-fired electric generators.

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32. a. Prepared Direct Testimony on behalf of Watson Cogeneration Company (A. 00-06-032 — September 18, 2000).
b. Prepared Rebuttal Testimony on behalf of Watson Cogeneration Company (A. 00-06-032 — October 6, 2000).

- Rate design for a natural gas "peaking service."


- Terms and conditions of natural gas service to electric generators; gas curtailment policies.


- Avoided cost pricing for alternative energy producers in California.

b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of Wild Goose Storage (A. 01-06-029—November 2, 2001)

- Consumer benefits from expanded natural gas storage capacity in California.

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the County of San Bernardino (I. 01-06-047—December 14, 2001)

- Reasonableness review of a natural gas utility's procurement practices and storage operations.

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 01-10-024—May 31, 2002)
b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 01-10-024—May 31, 2002)

- Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.
38. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Manufacturers & Technology Association (R. 02-01-011—June 6, 2002)
   • “Exit fees” for direct access customers in California.

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the County of San Bernardino (A. 02-02-012 — August 5, 2002)
   • General rate case issues for a natural gas utility; reasonableness review of a natural gas utility’s procurement practices.

   • Recovery of past utility procurement costs from direct access customers.

   • Rate design issues for Pacific Gas & Electric’s gas transmission system (Gas Accord II).

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc. (R. 02-06-041 — March 21, 2003)
   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc. (R. 02-06-041 — April 4, 2003)
   • Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the California Wind Energy Association (R. 01-10-024 — April 1, 2003)
   • Design and implementation of a Renewable Portfolio Standard in California.
R. THOMAS BEACH  
Principal Consultant  

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 01-10-024 — June 23, 2003)
   b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 01-10-024 — June 29, 2003)

   • Power procurement policies for electric utilities in California.


   • Electric revenue allocation and rate design for commercial customers in southern California.

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of Calpine Corporation and the California Cogeneration Council (A. 04-03-021 — July 16, 2004)
   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of Calpine Corporation and the California Cogeneration Council (A. 04-03-021 — July 26, 2004)

   • Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (A. 04-04-003 — August 6, 2004)

   • Policy and contract issues concerning cogeneration QFs in California.

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council and the California Manufacturers and Technology Association (A. 04-07-044 — January 11, 2005)
   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the California Cogeneration Council and the California Manufacturers and Technology Association (A. 04-07-044 — January 28, 2005)

   • Natural gas cost allocation and rate design for large transportation customers in northern California.

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Manufacturers and Technology Association and the Indicated Commercial Parties (A. 04-06-024 — March 7, 2005)
   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the California Manufacturers and Technology Association and the Indicated Commercial Parties (A. 04-06-024 — April 26, 2005)

   • Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.

Crossborder Energy
50. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Solar Energy Industries Association (R. 04-03-017 — April 28, 2005)
   - Cost-effectiveness of the Million Solar Roofs Program.

51. Prepared Direct Testimony of R. Thomas Beach on behalf of Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association (A. 04-12-004 — July 29, 2005)
   - Natural gas rate design policy; integration of gas utility systems.

52. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 04-04-003/R. 04-04-025 — August 31, 2005)
   - Avoided cost rates and contracting policies for QFs in California

   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the California manufacturers and Technology Association and the Indicated Commercial Parties (A. 05-05-023 — February 24, 2006)
   - Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.

   b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the California Producers (R. 04-08-018 — February 21, 2006)
   - Transportation and balancing issues concerning California gas production.

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Manufacturers and Technology Association and the Indicated Commercial Parties (A. 06-03-005 — October 27, 2006)
   - Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (A. 05-12-030 — March 29, 2006)
   - Review and approval of a new contract with a gas-fired cogeneration project.

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57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association (A. 04-12-004 — July 14, 2006)

b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association (A. 04-12-004 — July 31, 2006)

- Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (R. 06-02-013 — March 2, 2007)

- Utility procurement policies concerning gas-fired cogeneration facilities.


b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Alliance (A. 07-01-047 — September 24, 2007)

- Electric rate design issues that impact customers installing solar photovoltaic systems.

60. a. Prepared Direct Testimony of R. Thomas Beach on Behalf of Gas Transmission Northwest Corporation (A. 07-12-021 — May 15, 2008)


- Utility subscription to new natural gas pipeline capacity serving California.

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Alliance (A. 08-03-015 — September 12, 2008)

b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the Solar Alliance (A. 08-03-015 — October 3, 2008)

- Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Alliance (A. 08-03-002 — October 31, 2008)

- Electric rate design issues that impact customers installing solar photovoltaic systems.

Crossborder Energy
63.  a.  Phase II Direct Testimony of R. Thomas Beach on behalf of Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company (A. 08-02-001 — December 23, 2008)
b.  Phase II Rebuttal Testimony of R. Thomas Beach on behalf of Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company (A. 08-02-001 — January 27, 2009)

- Natural gas cost allocation and rate design issues for large customers.

64.  a.  Prepared Direct Testimony of R. Thomas Beach on behalf of the California Cogeneration Council (A. 09-05-026 — November 4, 2009)

- Natural gas cost allocation and rate design issues for large customers.


- Revisions to a program of firm backbone capacity rights on natural gas pipelines.

66.  Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Alliance (A. 10-03-014 — October 6, 2010)

- Electric rate design issues that impact customers installing solar photovoltaic systems.


- Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.
68. a. Supplemented Prepared Direct Testimony of R. Thomas Beach on behalf of 
Sacramento Natural Gas Storage, LLC (A. 07-04-013 — December 6, 2010)
b. Supplemented Prepared Rebuttal Testimony of R. Thomas Beach on behalf of
Sacramento Natural Gas Storage, LLC (A. 07-04-013 — December 13, 2010)
c. Supplemented Prepared Reply Testimony of R. Thomas Beach on behalf of
Sacramento Natural Gas Storage, LLC (A. 07-04-013 — December 20, 2010)

• Local reliability benefits of a new natural gas storage facility.

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar
Energy Industries Association and the Solar Alliance, (Docket 09AL-299E – October 2,
2009).

• Electric rate design policies to encourage the use of distributed solar generation.

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the Nevada Geothermal Industry Council
(Docket No. 97-2001—May 28, 1997)

• Avoided cost pricing for the electric output of geothermal generation facilities in
Nevada.

2. Pre-filed Direct Testimony on Behalf of Nevada Sun-Peak Limited Partnership
(Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the Nevada Geothermal Industry Council
(Docket No. 98-2002 — June 18, 1998)

• Market-based, avoided cost pricing for the electric output of geothermal
generation facilities in Nevada.

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the Interstate Renewable Energy
Council (Case No. 10-00086-UT—February 28, 2011)

• Testimony on proposed standby rates for new distributed generation projects.

Crossborder Energy
EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

   b. Surrebuttal Testimony of Behalf of Weyerhaeuser Company (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities (UM 1129 / Phase II — April 7, 2006)

   • Policies to promote the development of cogeneration and other qualifying facilities in Oregon.

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

• The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).

• The valuation of a contract for the purchase of power produced from wind generators.

• The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.

• Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).

• The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.
Exhibit RTB-2

Selected Discovery Responses from PNM
RESPONSE TO THE EMAIL OF MR. THRONE DATED SEPTEMBER 22, 2011

1. PNM’s Objection to REIA 1-3 on Relevance and Burdensome Grounds:

   The “Projected Retail Sales” volumes shown in Exhibit CDB-2, Table 2 were not prepared on the basis of individual rate classes. Consequently, an exact calculation as requested cannot be made without a substantial investment of time and resources.

   The revenue shown for 2010 in Tables 4 and 5 of Exhibit CDB-4 are $797.3 million, as well as the applicable RCT percentages. The revenue increase approved in Case No. 10-00086-UT was $72.1 million. Reported retail sales for 2010 were 8,299,183 MWh (from PNM’s Renewable Energy Procurement Report for 2010). Using such information, in conjunction with the information shown in Exhibit CDB-4, an approximation of projected revenues and the RCT revenue cap could be calculated as follows:

   **Illustrative Calculation**
   
   $797.3 million + $72.1 million = $869.4 million

   2012 Factor = 8,843,583/8,299,183 = 1.0656
   2012 Revenues = 1.0656*$869.4 million = $926.4 million
   RCT = $926.4 million * 2.25% = $20.8 million

   2013 Factor = 8,934,983/8,299,183 = 1.0766
   2013 Revenue = 1.0766*$869.4 million = $936.0 million
   RCT = $936.0 million * 2.5% = $23.4 million

2. PNM’s Objection to REIA 1-4 on Relevance and “Outside the Scope of Case” Grounds:

   In preparing PNM’s Revised Renewable Energy Portfolio Procurement Plan for 2011 (Revised 2011 Plan), Case No. 10-00373-UT, PNM had conducted resource cost calculations and RCT calculations using the levelized methodology set forth in Case No. 10-00037-UT, but had not presented it in its filing; therefore, PNM was able to provide that information to you with relatively minimal additional effort. In the present case, no levelized RCT calculations have been prepared. Consequently, the burden to provide such information in this case is much greater than in the last case.

   The levelized cost for a project over its projected 20 or 30 year life, is the levelized cost over that period – it does not change from year to year; it would change only if the methodology for calculating the cost is changed or if the assumed values for the key variables used in the calculation changed. PNM has not changed the cost levelization methodology, or the assumptions thereto, set forth in Case No. 10-00037-UT;
RESPONSE TO THE EMAIL OF MR. THRONE DATED SEPTEMBER 22, 2011

PNM is simply no longer using that methodology for purposes of comparing renewable energy resource costs to the RCT.

Using the methodology and assumptions set forth in Case No. 10-00037-UT would result in the same levelized costs as shown in PNM Exhibit REIA-4 for 2010-2011 or 2012-2013 — i.e., it is the cost levelized over the life of that resource.

5. PNM’s Response to REIA 1-8(b):

PNM believes that PNM Exhibit REIA 1-8b is fully responsive to the Interrogatory. However, in light of the further detail requested in your September 22 email, PNM is providing additional information concerning the revenue requirements associated with the 22 MW of solar PV projects authorized in Case No. 10-00037-UT; this information is set forth in the excel files attached with PNM’s responding email.

As for carrying charges, pages 6 and 7 of PNM Exhibit REIA 1-8b show the amount of carrying charges in the fourth from left column based on the Carrying Charge Rate of 8.64% as documented on the third line up from the bottom.

6. PNM’s Response to REIA 1-12:

There are no additional responsive work papers. The procurement volume of 4,680 MWh assumed a $0.02 per kWh price and an annual expenditure of approximately $100,000.
PUBLIC SERVICE COMPANY OF NEW MEXICO'S OBJECTIONS AND RESPONSES TO REIA'S FIRST SET OF INTERROGATORIES AND REQUESTS FOR PRODUCTION OF DOCUMENTS

Public Service Company of New Mexico ("PNM") hereby responds to REIA's First Set of Interrogatories and Requests for Production of Documents ("Requests").

GENERAL OBJECTION

PNM objects to Staff’s instructions and directions to the extent they seek to supplement or modify the requirements of 17.1.2.28 NMAC, et seq, or the Rules of Civil Procedure for the District Courts of New Mexico.

PNM objects to the Staff’s Requests to the extent they seek information protected from disclosure by the attorney-client privilege or the work product doctrine. Rules 1-026 and 11-503 NMRA 2000; 1.2.28.C NMAC.

In responding to these Requests, PNM reserves all evidentiary objections to any responses or documents that may be offered in evidence in this proceeding.

PNM responds to these Requests subject to, and without waiving, these objections.
RESPONSE:
PNM's is aware the RCT methodology EPE and SPS have used in some plans incorporates some aspects of a “levelized” approach to calculating the RCT; however, PNM is not aware that the Commission specifically approved an RCT methodology in those cases.

* In a recent SPS case in which the RCT methodology was an issue, the Hearing Examiner stated in the Findings and Conclusions that “…the Commission does not determine which RCT methodology is appropriate in this case.” (Case No. 10-00015-UT, Recommended Decision, Findings and Conclusions, Paragraph 6, page 53.)

* In Case No. 10-00200-UT addressing EPE’s 2010 renewable energy plan, Hearing Examiner stated that a “…decision determining which methodology to be applied is unnecessary in this proceeding.” (Case No. 10-00200-UT, Recommended Decision, page 23.)

REIA 1-8: Please provide projected RCT calculations for 2011 and 2012 using the same “levelized” approach to calculate the RCT used by PNM to calculate the RCT in PNM’s Revised 2010 Plan case (#10-00037-UT).
RESPONDENT: Cindy Bothwell

RESPONSE:
PNM objects to this Interrogatory on the grounds that it calls for calculations that have not been performed. NMAC 1.2.25.B; NMRA 1-026(B)(2) Without waiving this objection, PNM responds that all of the information needed to calculate the requested adjustments to Table 2 is provided in the executable worksheet Corrected PNM Exhibit ABCWUA 1-6b.

REIA 1-9: Please provide the following information concerning these PNM discovery responses:
a. [PNM Ex. ABCWUA 1-6.b, first page, Solar Incentive Program (“SIP”) estimates] provide actual kWhs provided by each system size component of PNM’s SIP as of year-end 2010 (note: this PNM Exhibit appears to provide “estimates” only and PNM’s Response to ABCWUA 1-2 provides installed SIP capacity but not production data as of 1/1/2011);
b. provide actual kWhs provided by each system size component of PNM’s SIP as of March 1, 2011;
c. state the solar facility completion deadline date for each of the “pending applications” for systems greater than 10 kW AC capacity indicated in PNM’s Response to ABCWUA 1-2, broken down by SIP system size category;
d. [PNM Ex. ABCWUA 1-6.b, second page entitled “PNM Solar RECs-45 MW”] explain what the “45 MW” refers to and how the figures on this page relate to any of PNM’s RPS or RCT calculations in its “Corrected” Plan filing;
e. [PNM Ex. ABCWUA 1-6.b, page entitled “Project Actual Revenue Requirements”] explain how the projected annual revenue requirements for “PV-22MW” and “Battery 500 kW” for 2011 and 2012 relate to any of the RCT calculations for those elements of PNM’s Plan shown on Exhibit CDB-5 to Ms. Bothwell’s Direct Testimony.
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**Revised Table 4: Projected RCT Calculation for 2011 using Levelized Costs**
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</tr>
<tr>
<td>2019</td>
<td>SMWPE_Considering</td>
<td>Key Regs</td>
<td>Internal</td>
<td>Internal</td>
<td>Resource</td>
</tr>
<tr>
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<td>SMWPE_Considering</td>
<td>Key Regs</td>
<td>Internal</td>
<td>Internal</td>
<td>Resource</td>
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<td>Key Regs</td>
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</tbody>
</table>

Revised Table 2: Projected RCT Calculation for 2012 Using Levelized Costs
Exhibit RTB-3

PNM’s Avoided Generation and Transmission Capacity Costs
Tariff Collections

The information is this section is in compliance with the Final Order issued by the Commission in Case No. 07-00053-UT which requires tariff rider reconciliation information to be filed on April 1 of each year.

The direct costs of implementing the Program are recovered through the Energy Efficiency Fee on customers' bills. Beginning with the first billing cycle of October 2007, PNM implemented tariff Rider 16 ("Rider 16") and tariff Rider 1 ("Rider 1") on all affected customers' bills. These riders were set at 1.288 percent of bills. Beginning with the first billing cycle of August 2009, the Energy Efficiency Fee was set at 1.881 percent of bills as approved in Case No. 08-00204-UT. During program year 2009, PNM recovered a total of $10,510,829. Actual expenses for program year 2009 were $12,096,301, which results in an under collection of $1,585,472. However, PNM reported an over collection of $1,512,540 in its annual report for program year 2008. Therefore, there was a net under collection of $72,932 at the end of program year 2009. PNM will propose in its next energy efficiency program plan filing that this under-recovered amount be added to the projected annual budget for program year 2011. PNM anticipates filing a new program plan on or before June 30, 2010.

Regulatory Proceedings

On March 3, 2009, the Commission approved the selection of ADM Associates ("ADM") as the state-wide independent evaluator. PNM has contracted with ADM for evaluation services beginning in 2010. ADM will evaluate the new programs approved in Case No. 08-00204-UT for program year 2009 and all programs for program year 2010. On May 19, 2009 the Commission approved the PNM portfolio of energy efficiency programs in Case No. 08-00204-UT.

Independent Evaluation

Background and Purpose

The Rule requires that an independent evaluator conduct measurement and verification assessments of all energy efficiency and load management programs. Through a competitive bidding process, PNM selected and hired an independent program evaluator, RLW Analytics ("RLW"), to perform evaluation, measurement and verification of the PNM Energy Efficiency Program for the 2008 and 2009 program years. RLW Analytics was acquired by KEMA in January 2009 and the 2009 M&V Report was prepared and submitted by KEMA. The M&V Report for program year 2009 includes data from January 1, 2009 through December 31, 2009. PNM worked closely with KEMA to provide them with the data necessary to complete the 2009 M&V Report. This included rebate processing and participant files, budget data by program and avoided-cost information.

---

2 PNM submitted all available program data to KEMA in mid-January 2010. A small number of invoices submitted to PNM from its third-party contractors were not completed until the end of January. Consequently, some of the final year-end unit numbers contained in PNM's annual report vary slightly from the values submitted to KEMA.
The M&V report prepared by KEMA and submitted along with this annual report does not include evaluation of new programs approved in May 2009. The new programs were not available for customer participation until July 1, 2009 which did not leave enough time for KEMA to adequately evaluate them by the end of the year. The Energy Efficiency Evaluation Committee, appointed by the Commission, selected ADM as the state-wide independent evaluator and this selection was approved by the Commission on March 3, 2009. ADM will conduct independent evaluation of the new programs for program year 2009 and for all programs in program year 2010. The report covering the new programs for program year 2009 is expected to be completed in July 2010. The new programs are indicated by an asterisk in the table on page 10 of this report; however, the new Market Transformation program is not subject to evaluation since PNM is not claiming savings from that program.

The primary purpose of the independent evaluation is to assess the cost effectiveness of the programs using the TRC test, which includes a thorough analysis of achieved savings and free rider estimation. A secondary purpose of the evaluation is to perform a basic process evaluation of the Program to determine customer satisfaction with how the programs operated and provide suggestions to improve delivery to customers.

Summary of Findings and PNM Comments

All of the programs evaluated were found to be cost effective and the total Program portfolio was found to be cost effective. The results of the M&V analysis were used to adjust a number of technical assumptions made by PNM regarding Program performance, including the average savings per unit and average customer expense. The M&V Report contains many other findings and recommendations. A summary of some of the more important findings and recommendations along with comments from PNM is provided below.

1) Each of the programs that KEMA evaluated were found to be cost effective and the total portfolio of the PNM Energy Efficiency Program was cost effective.

2) The Business Lighting Program was found to have a very high realization rate which means that nearly all of the reported measures were found to be installed as reported. KEMA recommended expansion of the program to include more measures, to enhance the PNM website and application, to base incentives on savings and to do more outreach with contractors.

*PNM RESPONSE:* The Business Lighting Program was ended as a stand-alone program in July 2009. The lighting measures have been absorbed into the larger Commercial Comprehensive Program which includes many more measures. The Commercial Comprehensive Program also includes an enhanced website and application, incentives based on energy savings and full-time staff that work directly with contractors and potential participants.

3) Evaluation of the ENERGY STAR Home Program showed that 75 percent of the home buyers were influenced by the ENERGY STAR rating on their home and 85 percent believed the rating was worth the extra cost. The energy consumption of
Appendix A – PNM Avoided Costs

The following table provides the avoided energy costs for program year 2009. These costs were used by KEMA in their program evaluation and in the PNM TRC model. The costs are the same as those approved in Case No. 08-00204-UT with the exception of the CO2 adder which is consistent with the PNM 2008 Integrated Resource Plan and the natural gas forecast, which is consistent with the gas energy efficiency plan filed by NMGCO in May 2009.

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<th>Units:</th>
<th>Annual Energy $/kWh</th>
<th>Summer Capacity $/kW-yr</th>
<th>CO2 $/MWh</th>
<th>Natural Gas Forecast Per Therm</th>
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<td>2009</td>
<td>2009</td>
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<td>$0.0777</td>
<td>$91.71</td>
<td>$-</td>
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## Transmission Unit MC by Season and Voltage Level

### Demand Losses by Voltage Level

(Source: Information - 13, Lines 1 through 6)

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<thead>
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<th>Line #</th>
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<th>Demand</th>
<th>Losses</th>
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<tr>
<td>1</td>
<td>High Distribution</td>
<td>1</td>
<td>0.22%</td>
<td></td>
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<tr>
<td>2</td>
<td>Substation</td>
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<td>0.64%</td>
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<tr>
<td>3</td>
<td>Primary Distribution</td>
<td>1</td>
<td>1.62%</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Secondary Distribution</td>
<td>1</td>
<td>2.28%</td>
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### Seasonal Allocators

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<th>Line #</th>
<th>Description</th>
<th>Note</th>
<th>Annual</th>
<th>Summer</th>
<th>Other</th>
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<tr>
<td>5</td>
<td>Allocated Unit Marginal Cost</td>
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<td>$344.05</td>
<td>$143.35</td>
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<td>6</td>
<td>Seasonal Allocator</td>
<td>3</td>
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<td>0.4167</td>
<td>0.5833</td>
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<td>7</td>
<td>Months in Season</td>
<td></td>
<td>12</td>
<td>5</td>
<td>7</td>
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### Transmission Unit MC per Month by Season and Voltage Level

(Allocated Unit Marginal Cost / Cumulative Voltage Factor / Months in Season)

<table>
<thead>
<tr>
<th>Line #</th>
<th>Voltage Level</th>
<th>Note</th>
<th>Cumulative Voltage Factor</th>
<th>Annual</th>
<th>Summer</th>
<th>Other</th>
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<tbody>
<tr>
<td>8</td>
<td>Transmission Voltage (14 - Mining [115 kV] &amp; 15 - Universities [115 kV])</td>
<td>4</td>
<td>100.00%</td>
<td>$28.671</td>
<td>$28.671</td>
<td>$28.671</td>
</tr>
<tr>
<td>9</td>
<td>High Distribution Voltage (5 - Mining [46/69 kV])</td>
<td>5</td>
<td>100.22%</td>
<td>$28.735</td>
<td>$28.735</td>
<td>$28.735</td>
</tr>
<tr>
<td>11</td>
<td>Primary Distribution Voltage (4 - Large Power &amp; 11 - Water &amp; Sewage)</td>
<td>7</td>
<td>102.50%</td>
<td>$29.387</td>
<td>$29.387</td>
<td>$29.387</td>
</tr>
<tr>
<td>12</td>
<td>Secondary Distribution Voltage (1 - Residential, 2 - Small Power, 3 - General Power, 6 - Private Lighting, 10 - Irrigation, 19&amp;20 - Streetlighting)</td>
<td>8</td>
<td>104.84%</td>
<td>$30.057</td>
<td>$30.057</td>
<td>$30.057</td>
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</tbody>
</table>

Notes:
1. Source: Information - 13, Demand Losses Column, Lines 3 through 6
2. Source: Transmission - 2, Line 18
3. (Line 7) / (Annual total of Line 7)
4. Cum. Voltage Factor = 100%
5. Cum. Voltage Factor = Line 8 * (1 + Line 1)
6. Cum. Voltage Factor = Line 8 * (1 + Line 2)
7. Cum. Voltage Factor = Line 10 * (1 + Line 3)
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,

PUBLIC SERVICE COMPANY OF NEW MEXICO,

Petitioner,

Case No. 11-00265-UT

AFFIDAVIT OF R. THOMAS BEACH

STATE OF CALIFORNIA )
) ss.
COUNTY OF ALAMEDA )

I, R. Thomas Beach, being first duly sworn on oath, state as follows:

1. I have read the foregoing Direct Testimony and Exhibits and the contents thereof are true and accurate based on my personal knowledge and belief.

FURTHER AFFIANT SAYETH NOT.

R. Thomas Beach

SUBSCRIBED AND SWORN before me on this 3rd day of October 2011.

My Commission Expires:

05/23/2015
Respectfully submitted this 3rd day of October, 2011.

HOLLAND & HART LLP

[Signature]

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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE
COMPANY OF NEW MEXICO'S
RENEWABLE ENERGY PORTFOLIO
PROCUREMENT PLAN FOR 2012

PUBLIC SERVICE COMPANY OF NEW MEXICO

Petitioner.

Case No. 11-00265-UT

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony and Exhibits of R. Thomas Beach on Behalf of The New Mexico Independent Power Producers was mailed first-class, postage-paid, or hand-delivered on October 3, 2011 to the following persons whose mailing addresses are listed below and emailed to those persons at the email addresses shown below:

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Dated this 3rd day of October, 2011.

By: 

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