**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

**IN THE MATTER OF THE APPLICATION )**
**OF PUBLIC SERVICE COMPNAY OF NEW )**
**MEXICO FOR APPROVAL OF ELECTRIC )**
**ENERGY EFFICIENCY PROGRAMS AND )**
**PROGRAM COST TARIFF RIDER )**
**PURSUANT TO THE NEW MEXICO ) CASE NO. 12-00317-UT**
**PUBLIC UTILITY AND EFFICIENT USE )**
**OF ENERGY ACTS, )**
**)**
**PUBLIC SERVICE COMPANY OF )**
**NEW MEXICO )**
**)**
**Applicant )**

**REBUTTAL TESTIMONY**

**OF**

**BRUNO E. CARRARA**

**ON BEHALF OF**

**NEW MEXICO PUBLIC REGULATION COMMISSION**
**UTILITY DIVISION**

**6 February 2013**

**Q. Please state your name, position and business address.**

**A.** My name is Bruno E. Carrara. I am the Bureau Chief for the Electrical Engineering Bureau of the Utility Division of the New Mexico Public Regulation Commission ("NMPRC", "PRC", or "Commission"). My business address is New Mexico Public Regulation Commission, P.E.R.A. Building, 1120 Paseo de Peralta, Santa Fe, New Mexico 87504. My e-mail address is bruno.carrara@state.nm.us.

**Q: Did you submit direct testimony in this case?**

Yes. I submitted direct testimony on January 23, 2013. My direct testimony addresses the calculations performed by Public Service Company of New Mexico ("PNM" or "Company") and used in the benefits side of the total resource test calculation ("TRC"), as well as PNM's incentive proposal; provides a utility cost analysis; and provides the calculations to support Staff's incentive proposal.

**Q: What is the purpose of your rebuttal testimony?**

**A:** I am responding to certain topics discussed in the testimonies submitted by Attorney General's ("AG") Witness Gegax, New Mexico Industrial Energy Consumer's ("NMIEC") Witness Bothwell, and Western Resource Advocates' and Coalition for Clean and Affordable Energy's (collectively "WRA/CCAE") Witness Curl. Specifically, I am responding to WRA/CCAE's regulatory asset and incentive recommendation; the AG's "backstop" incentive proposal of $648,819; NMIEC's recommendation to value deferred capacity at $0 for TRC calculations; and NMIEC's incentive recommendations.

**Q: Please Respond to WRA/CCAE's regulatory asset and incentive proposal and provide the basis for Staff's opposition.**

A: WRA/CCAE recommends that PNM be required to establish a regulatory asset to be collected over 8 years, which is the average of the 2013 and 2014 program lives in PNM's proposed 2012 plan. In Staff Rebuttal Exhibit BEC-1RB, I have restated WRA/CCAE's Exhibit JEC-1 by expanding the return into the common equity, preferred equity, and debt components to demonstrate the cost impact and proposed incentive amount of WRA/CCAE's regulatory asset proposal. I also included a minor correction for the income tax gross up of the equity components. WRA/CCAE's approach is similar to the regulatory asset proxy component of the incentive method proposed by Staff, but it is very different in important ways:

- Requiring an actual regulatory asset as recommended by WRA/CCAE for 2013 programs increases the costs of the programs from approximately $22.5 million to $35.5 million, or nearly 58%. The $13 million increase arises from approximately $9.8 million in incentive, and $3.2 million in debt. The rider collection mechanism proposed in this case eliminates any need for debt. A similar dollar increase would result for the 2014 programs. These increases do little to further energy efficiency and load management goals, and are therefore unnecessary and would result in economic harm to customers. Projected "administrative and third party costs" for the 2013 EE and LM programs are already at 50.4% of total program cost (without incentive included) (PNM Witness Bean Direct, page 44, Table 7).

- CCAE/WRA's proposal gives PNM a "premium" to PNM's equity component in the weighted average cost of capital by increasing the amount by 110% and then by grossing the amount for tax liability. The net effect of these recommendations is that PNM would receive an incentive "profit" of $9,857,516 (the corrected amount) -- more than twice what PNM requested. Staff strongly disagrees that an extra incentive needs to be included. Staff also strongly disagrees that the tax liability gross-up should be included on what is essentially a "wind-fall" profit.
- WRA/CCAE's proposal gives all the reward to the Company while leaving all the risk with customers and does not provide for a sharing of the rewards with customers.
- WRA/CCAE's proposal fails to consider the impact that the program cost increases would have on the TRCs.

Because of the 58% increase to program costs and $9.8 million incentive resulting from WRA/CCEA's regulatory asset proposal, WRA/CCAE's proposal results in inappropriate cost increases and would provide the Company an unjust windfall profit to the detriment of ratepayers. The proposal is therefore contrary to the public interest, and should be rejected by the Commission.

**Q: Please respond to the AG's testimony supporting a $648,819 profit incentive if the Commission uses PNM's proposed methodology and provide the basis of Staff's disagreement.**

**A:** The AG recommends an EUEA incentive in the amount of $648,819 based on different assumptions to PNM Witness Graves's methodology. While the AG recommends rejection of PNM's proposed "lost profit" methodology as a basis of the EUEA incentive, its $648,819 proposal is a backstop measure if the Commission determines to use that methodology. Staff disagrees with the AG's proposal because it relies on the calculations performed by PNM for the deferred kW capacity benefits and costs. As pointed out by the AG, the specific calculations performed by PNM for the deferred kW capacity benefits and costs "lost profit" argument are unreliable, highly dependent on the underlying assumptions made, and should be rejected as a basis for determining a EUEA incentive. Because PNM's method does not accurately reflect likely proposed system benefits (Staff Witness Lamberson Direct, p. 7) and is inherently flawed (Staff Witness Carrara Direct, p. 21), it should not be used as a basis for a EUEA incentive even with the assumptions provided by the AG. Rather, the calculations supporting Staff's incentive proposal should be adopted for purposes of this case. Contrary to the AG's proposal, the calculations I present in my direct testimony to support Staff's incentive proposal are the only calculations presented that incorporate components in this case that are not contested; namely: the program cost, which Staff handled through a regulatory asset proxy (this notion is actually endorsed by AG Witness Gegax at page 3 of his direct testimony), and the avoided kWh energy deemed savings.

**Q: Please respond to NMIEC's proposal to value deferred capacity at $0 per kW-year for TRC test purposes and provide the basis for Staff's opposition to this recommendation.**

**A:** NMIEC testifies that PNM improperly calculated its planning reserve margin because PNM treated Load Management ("LM") programs as a system resource rather than as a "Net Internal Demand" reduction. NMIEC states that using LM as a system resource understates the reserve margin percentage. A 13% reserve margin target is used by the Strategist model as the decision point for selecting when an additional generating resource is required. NMIEC corrected PNM's reserve margin calculation and concluded that no additional capacity would be deferred when the 2013 and 2014 energy efficiency ("EE") programs <u>are stacked on top of five years' (2013-2017) of LM programs</u> (NMIEC Witness Bothwell Direct, p.1). Staff agrees that NMIEC's planning reserve margin method is more consistent with the annual utility reporting requirements to the US Energy Information Administration, but Staff is also aware that treating LM as a network resource as in its Application is consistent with the LM treatment in PNM's 2011-2030 Electric Integrated Resource Plan and in other documents and cases. See, for example, Staff Rebuttal Exhibit BEC-2RB, which is the Load and Resources Table from PNM's 2011-2030 IRP, the line referred to as "Demand Response Programs" under the Firm-Dispatchable Resources category. Further, NMIEC's analysis does not demonstrate that annual deferred kW capacity savings and costs do not occur. Staff does not agree with NMIEC's proposal to value deferred capacity kW savings and costs at $0 for the TRC calculation in this proceeding for the following reasons:

- NMIEC's analysis fails to consider the apparent "shrinkage" for EE programs presented by PNM and discussed in my direct testimony at page 15. NMIEC also does not apply any shrinkage factor to LM even though the estimate of the future amount kW savings from the LM resources has decreased over time. A difference of a few megawatts could cause a difference in when the planning reserve margin threshold is crossed and could result in an acceleration or delay of when additional generation is needed in critical years such as 2014, 2016, or 2021 (Staff Rebuttal Exhibit BEC-3RB, Table 3).
- NMIEC did not analyze alternate "baseline" case assumptions to determine if alternate baselines calculations would be more appropriate. For example, the baseline proposed by PNM includes five years of LM – the Power Saver and Peak Saver programs -- even though PNM's 2012 plan only includes LM programs in 2013 and 2014. The Commission can and should analyze whether programs previously approved should be continued into the future and to include five years of LM through 2017 sidesteps the Commission's review. Certainly

conditions have changed since the LM programs were originally approved, and it is proper for the Commission to consider the 2013 and 2014 LM programs in this case. By using the baseline case as proposed by PNM, NMIEC limits its analysis to a narrow set of assumptions that, with NMIEC's reserve planning margin recalculation, leaps to the conclusion that EE programs have no capacity value. If, for example, NMIEC had considered only two years of LM programs and EE programs, 2013 and 2014, consistent with the 2012 plan, the results from Strategist could have been significantly different. This is demonstrated in Exhibit BEC-3RB. Table 1 and 2 in Exhibit BEC-3RB summarize the conclusions reached in NMIEC Exhibit CB-4 and CB-5, and Table 3 in Exhibit BEC-3RB shows what one possible outcome could be if only the 2013 and 2014 EE and LM programs are considered. Note that the required generation addition for 2013-2021 is actually less in Table 3 than in either Table 1 or Table 2. PNM's response to Staff Interrogatory 1-9 (Staff Rebuttal Exhibit BEC-4RB) shows that savings occurred as a result of a scenario that includes both LM and EE as opposed to a scenario that only includes LM. Therefore, looking at only a narrow set of circumstances, as NMIEC did, and concluding that EE programs have no impact (much less whether there are savings or costs associated with such generation acceleration or delay) is not well-founded.

- Finally, using PNM's baseline case and eliminating EE from the consideration does not substantiate using $114.88 per kW-year as the deferred kW capacity savings or costs for the LM programs' TRC calculations. This is further discussed below.

In summary, NMIEC eliminated deferred kW capacity savings or costs for the EE programs thereby reducing the TRC calculation to only an avoided energy calculation. The elimination resulted in their recommendation that several programs be denied because the recalculated TRC fell below 1.0. NMIEC did not adjust the TRC values in PNM's application for LM programs. It is Staff's position that NMIEC has not demonstrated that the annual deferred kW capacity savings and costs for EE are zero and has not demonstrated that the deferred capacity value for LM should be $114.88 per kW-year.

**Q: Given that your direct testimony questioned the PNM assumptions accepted by NMIEC, why then does Staff rely on PNM's methodology to calculate the deferred capacity kW savings and costs for the TRC calculations?**

**A:** NMIEC's conclusion to value deferred capacity benefits and costs at $0 for EE TRC calculations overlooks key assumptions which I addressed in my direct testimony. As stated in that testimony, Staff agrees that a portfolio analysis is appropriate because the EUEA requires a life cycle approach to the TRC. It is my understanding that PNM's methodology in this case is similar to, but not exactly the same, as used by PNM in previous cases where the avoided costs as proposed by PNM were not contested and indeed were accepted without analysis. Although I questioned the PNM assumptions relied upon by NMIEC in my direct testimony, Staff does not have an alternate method that has been rigorously developed and properly vetted to substitute for PNM's method. Staff then only corrected PNM's calculations for mathematical errors and calculated revised deferred kWh capacity values, $78.43 per kW-year for EE and $123.13 per kW-year for LM, for this case only and only for purposes of the TRC, not incentives.

**Q: Please respond to NMIEC's incentive proposal and provide the basis of Staff's disagreement.**

A: NMIEC recommends that PNM should not receive the requested incentive, or for that matter, any incentive. NMIEC's recommendation is primarily based on two conclusions:

1) NMIEC concludes that there are no capacity deferral resulting from the 2013 and 2014 EE programs: and

2) NMIEC concludes that the incentive should only be awarded for "satisfactory performance over and above that required by the EUEA and over and above the expected performance of a proposed plan" (NMIEC Witness Bothwell Direct, p. 24).

The first conclusion is discussed above. Staff notes that NMIEC has concluded that system capacity deferral benefits do not exist for EE programs only, but makes no such representation regarding the LM programs. In fact, NMIEC agrees that the TRC for the

2013 and 2014 LM programs are 1.35 (for Power Saver) and 2.37 (for Peak Saver) (NMIEC Witness Bothwell Direct, Exhibit CDB-8). A look behind these numbers in PNM testimony indicates that the TRC's for these programs are mostly composed of deferred capacity, which is valued at $114.02 per kW-year (Staff Rebuttal Exhibit BEC-5RB). There is no foundation for accepting this deferred capacity value. It also follows that if there were adequate foundation, then capacity deferral does exist and PNM might be entitled to some incentive. NMEIC's argument is inconsistent at best.

NMIEC does not believe that PNM has achieved the criteria in the second conclusion, and, when asked what the Commission should do if the Commission should nonetheless decide that an incentive should be awarded, responds with only general recommendations. NMIEC connects any incentive only to satisfactory performance "over and above" the amount required by the EUEA. Statute contains no such qualifier, but rather, only ties the incentive to "satisfactory program performance" (Section 62-17-5 NMSA 1978).

**Q:** **Does this conclude your testimony?**

**A:** Yes.

WRA/CCAE Exhibit JEC-1 Restated

| | |
|---|---|
| EE program cost | $ 22,493,227 |
| Return on regulated asset | 12.86% |
| Life of programs (yrs) | 8 |

| Year | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|
| Reg asset balance | $ 22,493,227 | $ 19,681,574 | $ 16,869,920 | $ 14,058,267 | $ 11,246,614 | $ 8,434,960 | $ 5,623,307 | $ 2,811,653 | |
| Return | | | | | | | | | |
| Common | $ 2,181,899 | $ 1,909,162 | $ 1,636,424 | $ 1,363,687 | $ 1,090,950 | $ 818,212 | $ 545,475 | $ 272,737 | $ 9,818,547 |
| Preferred | $ 8,660 | $ 7,577 | $ 6,495 | $ 5,412 | $ 4,330 | $ 3,247 | $ 2,165 | $ 1,082 | $ 38,970 |
| Debt | $ 702,704 | $ 614,866 | $ 527,028 | $ 439,190 | $ 351,352 | $ 263,514 | $ 175,676 | $ 87,838 | $ 3,162,170 |
| | $ 2,893,264 | $ 2,531,606 | $ 2,169,948 | $ 1,808,290 | $ 1,446,632 | $ 1,084,974 | $ 723,316 | $ 361,658 | $ 13,019,686 |
| Amortization | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 2,811,653 | $ 22,493,227 |
| Revenue Requirement | $ 5,704,917 | $ 5,343,259 | $ 4,981,601 | $ 4,619,943 | $ 4,258,285 | $ 3,896,627 | $ 3,534,969 | $ 3,173,311 | $ 35,512,913 |

| Total equity return | $ 9,857,516 |
|---|---|

| WACC | % Weight | Cost | Wtd cost | Pretax Wtd Cost | |
|---|---|---|---|---|---|
| Common | 50.61% | 11.50% | 5.82% | 9.70% | (This value is 9.64% in JEC-1) |
| Preferred | 0.50% | 4.62% | 0.02% | 0.04% | |
| Debt | 48.89% | 6.39% | 3.12% | 3.12% | |
| Total | 100.00% | | 8.97% | 12.86% | |

| | |
|---|---|
| Tax rate | 40% |
| Tax Factor | 1.66667 |
| | 1.6563147 |

| | | |
|---|---|---|
| Program cost: | $ 22,493,227 | |
| Equity return premium: | $ 9,857,516 | |
| Debt premium: | $ 3,162,170 | |
| Total program cost : | $ 35,512,913 | |
| Program cost increase for TRC: | $ 13,019,686 | 57.9% |

Source: WRA Exihibit JEC-1

STAFF REBUTTAL EXHIBIT BEC-2RB



TABLE 2-2. LOAD AND RESOURCES (L&R) TABLE (IRP RULE 17.7.3.9.E)

**PUBLIC SERVICE COMPANY OF NEW MEXICO**
**Total Load and Resource Projection (MW) for Summer Peak**
**2011 IRP Most Cost Effective Portfolio**

| | Duty Cycle | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2011 AOP Forecast Peak Demand** | | | 1,972 | 1,992 | 2,033 | 2,069 | 2,107 | 2,138 | 2,178 | 2,214 | 2,251 | 2,289 |
| Projected Customer Sited PV | | | (4) | (9) | (11) | (12) | (13) | (13) | (13) | (13) | (13) | (13) |
| Projected Energy Efficiency | | | (17) | (29) | (41) | (56) | (66) | (80) | (88) | (97) | (107) | (115) |
| Net System Peak Demand | | | 1950 | 1954 | 1981 | 2001 | 2026 | 2045 | 2077 | 2104 | 2131 | 2161 |
| Firm-Dispatchable Resources | | | | | | | | | | | | |
| Four Corners | B | coal | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| San Juan 1, 2, 3, 4 | B | coal | 810 | 810 | 810 | 810 | 810 | 810 | 810 | 810 | 810 | 810 |
| Palo Verde Units 1 & 2 | B | nuclear | 268 | 268 | 268 | 268 | 164 | 90 | 90 | 90 | 90 | 90 |
| *Future Palo Verde Acquisitions* | *B* | *nuclear* | *0* | *0* | *0* | *0* | *104* | *178* | *178* | *178* | *178* | *178* |
| Reeves 1, 2, 3 | P | natural gas | 154 | 154 | 154 | 154 | 154 | 154 | 154 | 154 | 154 | 154 |
| Afton CC | I | natural gas | 230 | 230 | 230 | 230 | 230 | 230 | 230 | 230 | 230 | 230 |
| Luna | I | natural gas | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 | 185 |
| Lordsburg | P | natural gas | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Valencia (Purchase) | P | natural gas | 145 | 145 | 145 | 145 | 145 | 145 | 145 | 145 | 145 | 145 |
| Delta-Person (Purchase) | P | natural gas | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 | 132 |
| *Future Natural Gas Additions* | *P* | *natural gas* | | | | | *40* | *80* | *257* | *257* | *257* | *257* |
| Demand Response Programs (Contract) | P | | 75 | 80 | 86 | 92 | 92 | 92 | 92 | 0 | 0 | 0 |
| *Future Demand Response (Contract)* | P | | | | | | | | | *92* | *92* | *92* |
| Total | | | 2,279 | 2,284 | 2,290 | 2,296 | 2,336 | 2,376 | 2,553 | 2,553 | 2,553 | 2,553 |
| **Firm Reserve Margin (MW)** | | | 307 | 292 | 257 | 227 | 229 | 238 | 375 | 339 | 302 | 264 |
| **Firm Reserve Margin (%)** | | | 15.6% | 14.7% | 12.6% | 10.9% | 10.9% | 11.1% | 17.2% | 15.3% | 13.4% | 11.5% |
| Non-Firm, Intermittent Resources | | | | | | | | | | | | |
| NM Wind Energy Center (Purchase) | | wind | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| PNM Solar | | | 7 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| *Future Renewable Additions* | | | | | | *8* | *8* | *8* | *8* | *8* | *40* | *40* |
| Total | | | 17 | 22 | 22 | 30 | 30 | 30 | 30 | 30 | 62 | 62 |
| **Reserve Margin including non-firm (MW)** | | | 346 | 352 | 331 | 324 | 340 | 361 | 505 | 478 | 483 | 454 |
| **Reserve Margin including non-firm (%)** | | | 17.7% | 18.0% | 16.7% | 16.2% | 16.8% | 17.6% | 24.3% | 22.7% | 22.7% | 21.0% |

The firm reserve margin is the difference between the forecast peak demand and the sum of the firm-dispatchable resources.
The non-firm reserve margin is the difference between the net system peak demand and the sum of the firm and non-firm resources.
Intermittent resources may require additional regulating reserve margins.

STAFF REBUTTAL EXHIBIT BEC-3RB

Planning Reserve Margin Comparison

| TABLE 1: WITHOUT 2013 AND 2014 PROPOSED EE PROGRAMS ("Baseline Case"): | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecasted peak | 2021.0 | 2050.8 | 2079.9 | 2110.3 | 2144.8 | 2185.4 | 2225.3 | 2268.7 | 2317.9 | | |
| EE Effecys (residual only) | 10.7 | 10.2 | 6.8 | 5.5 | 5.4 | 4.1 | 2.8 | 2.6 | 0.9 | | |
| Load management | 58.0 | 60.0 | 62.0 | 62.0 | 65.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Other adjustmnents | 14.1 | 14.0 | 13.9 | 13.9 | 13.8 | 13.7 | 13.7 | 13.6 | 13.5 | | |
| **Net Internal Demand** | **1938.2** | **1966.6** | **1997.2** | **2028.9** | **2060.6** | **2167.6** | **2208.8** | **2252.5** | **2303.5** | | |
| Net Capacity Resources | 2216.9 | 2225.5 | 2280.1 | 2370.6 | 2410.0 | 2547.3 | 2632.0 | 2631.9 | 2716.6 | error in CDB-5 | |
| *Capacity addition* | *0* | *0* | *40* | *85* | *0* | *177* | *85* | *0* | *85* | *Tot* | *472* |
| Planned Reserve Capacity (MW) | 278.7 | 258.9 | 282.9 | 341.7 | 349.4 | 379.7 | 423.2 | 379.4 | 413.1 | | |
| Planned Reserve Capacity (%) | 14.4% | 13.2% | 14.2% | 16.8% | 17.0% | 17.5% | 19.2% | 16.8% | 17.9% | | |
| Required Reserve Capacity (MW) | 252.0 | 255.7 | 259.6 | 263.8 | 267.9 | 281.8 | 287.1 | 292.8 | 299.5 | | |
| Required Reserve Capacity (%) | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | | |
| EXCESS RESERVE CAPACITY (MW) | 26.7 | 3.2 | 23.3 | 77.9 | 81.5 | 97.9 | 136.1 | 86.6 | 113.6 | | |

| TABLE 2: WITH 2013 AND 2014 PROPOSED EE PROGRAMS: | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecasted peak | 2021.0 | 2050.8 | 2079.9 | 2110.3 | 2144.8 | 2185.4 | 2225.3 | 2268.7 | 2317.9 | | |
| EE effects (residual plus 2013 and 2014) | 17.1 | 27.8 | 26.9 | 24.4 | 21.5 | 17.2 | 15.7 | 13.8 | 10.8 | | |
| Load management | 58.0 | 60.0 | 62.0 | 62.0 | 65.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Other adjustmnents | 14.1 | 14.0 | 13.9 | 13.9 | 13.8 | 13.7 | 13.7 | 13.6 | 13.5 | | |
| **Net Internal Demand** | **1931.8** | **1949.0** | **1977.1** | **2010.0** | **2044.5** | **2154.5** | **2195.9** | **2241.3** | **2293.6** | | |
| Net Capacity Resources | 2216.9 | 2225.5 | 2280.1 | 2370.6 | 2370.5 | 2547.3 | 2632.0 | 2631.9 | 2716.6 | error in CDB-5 | |
| *Capacity addition* | *0* | *0* | *40* | *85* | *0* | *177* | *85* | *0* | *85* | *Tot* | *472* |
| Planned Reserve Capacity (MW) | 285.1 | 276.5 | 303.0 | 360.6 | 326.0 | 392.8 | 436.1 | 390.6 | 423.0 | | |
| Planned Reserve Capacity (%) | 14.8% | 14.2% | 15.3% | 17.9% | 15.9% | 18.2% | 19.9% | 17.4% | 18.4% | | |
| Required Reserve Capacity (MW) | 251.1 | 253.4 | 257.0 | 261.3 | 265.8 | 280.1 | 285.5 | 291.4 | 298.2 | | |
| Required Reserve Capacity (%) | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | | |
| EXCESS RESERVE CAPACITY (MW) | 34.0 | 23.1 | 46.0 | 99.3 | 60.2 | 112.7 | 150.6 | 99.2 | 124.8 | | |

| TABLE 3: WITH 2013 AND 2014 PROPOSED EE PROGRAMS BUT WITHOUT LM AFTER 2014: | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecasted peak | 2021.0 | 2050.8 | 2079.9 | 2110.3 | 2144.8 | 2185.4 | 2225.3 | 2268.7 | 2317.9 | | |
| EE effects (residual plus 2013 and 2014) | 17.1 | 27.8 | 26.9 | 24.4 | 21.5 | 17.2 | 15.7 | 13.8 | 10.8 | | |
| Load management | 58.0 | 60.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | |
| Other adjustmnents | 14.1 | 14.0 | 13.9 | 13.9 | 13.8 | 13.7 | 13.7 | 13.6 | 13.5 | | |
| **Net Internal Demand** | **1931.8** | **1949.0** | **2039.1** | **2072.0** | **2109.5** | **2154.5** | **2195.9** | **2241.3** | **2293.6** | | |
| Net Capacity Resources | 2216.9 | 2216.9 | 2341.9 | 2341.9 | 2426.9 | 2466.9 | 2506.9 | 2591.9 | 2591.9 | | |
| *Capacity addition* | *0* | *0* | *125* | *0* | *85* | *40* | *40* | *85* | *0* | *Tot* | *375* |
| Planned Reserve Capacity (MW) | 285.1 | 267.9 | 302.8 | 269.9 | 317.4 | 312.4 | 311.0 | 350.6 | 298.3 | | |
| Planned Reserve Capacity (%) | 14.8% | 13.7% | 14.8% | 13.0% | 15.0% | 14.5% | 14.2% | 15.6% | 13.0% | | |
| Required Reserve Capacity (MW) | 251.1 | 253.4 | 265.1 | 269.4 | 274.2 | 280.1 | 285.5 | 291.4 | 298.2 | | |
| Required Reserve Capacity (%) | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | 13.0% | | |
| EXCESS RESERVE CAPACITY (MW) | 34.0 | 14.5 | 37.7 | 0.5 | 43.2 | 32.3 | 25.5 | 59.2 | 0.1 | | |

Source: NMIEC Witnes Bothwell Direct, p. 27, Exhibit CB-4, and Exhibit CB-5

## STAFF REBUTTAL EXHIBIT 4-RB

PNM Exhibit Staff 1-9
Formatted for Staff Attachment 1

| | Cumulative New Capacity (MW) | | | | | Annual Capacity and Fixed O&M ($000) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Scenario | No EE/ No LM | No EE/ LM | EE/ No LM | Res Light/ No LM | EE/ LM | No EE/ No LM | No EE/ LM | EE/ No LM | Res Light/ No LM | EE/ LM |
| 2013 | 0 | 0 | 0 | 0 | 0 | $0 | $0 | $0 | $0 | $0 |
| 2014 | 0 | 0 | 0 | 0 | 0 | $0 | $0 | $0 | $0 | $0 |
| 2015 | 40 | 40 | 40 | 40 | 40 | $12,941 | $12,941 | $12,941 | $12,941 | $12,941 |
| 2016 | 217 | 125 | 217 | 217 | 125 | $40,313 | $36,533 | $40,313 | $40,313 | $36,533 |
| 2017 | 217 | 165 | 217 | 217 | 125 | $39,031 | $48,947 | $39,031 | $39,031 | $35,351 |
| 2018 | 302 | 342 | 302 | 302 | 302 | $62,587 | $76,247 | $62,587 | $62,587 | $63,028 |
| 2019 | 387 | 342 | 302 | 387 | 302 | $86,194 | $73,540 | $60,402 | $86,194 | $60,878 |
| 2020 | 387 | 427 | 387 | 387 | 387 | $83,088 | $97,025 | $84,436 | $83,088 | $84,855 |
| 2021 | 472 | 427 | 472 | 472 | 472 | $106,886 | $93,553 | $108,551 | $106,886 | $108,972 |
| 2022 | 472 | 512 | 472 | 472 | 472 | $103,018 | $117,620 | $104,589 | $103,018 | $104,593 |
| 2023 | 649 | 552 | 649 | 649 | 649 | $131,971 | $129,155 | $133,449 | $131,971 | $133,837 |
| 2024 | 649 | 729 | 649 | 649 | 649 | $127,209 | $158,021 | $128,596 | $127,209 | $128,967 |
| 2025 | 649 | 729 | 649 | 649 | 649 | $122,159 | $152,195 | $123,525 | $122,159 | $123,890 |
| 2026 | 826 | 729 | 826 | 826 | 826 | $152,839 | $146,055 | $154,115 | $152,659 | $154,474 |
| 2027 | 826 | 906 | 826 | 826 | 826 | $147,149 | $176,575 | $148,405 | $147,149 | $148,758 |
| 2028 | 866 | 906 | 866 | 866 | 866 | $159,001 | $169,866 | $160,237 | $159,001 | $160,584 |
| 2029 | 866 | 906 | 866 | 866 | 866 | $152,520 | $162,850 | $153,835 | $152,620 | $154,177 |
| 2030 | 1043 | 991 | 1,043 | 1,043 | 1,043 | $185,375 | $189,821 | $186,570 | $185,375 | $186,906 |
| 2031 | 1043 | 991 | 1,043 | 1,043 | 1,043 | $178,237 | $182,428 | $179,412 | $178,237 | $179,742 |

Notes:
1. No EE = "Baseline" EE forecast (programs thorough 2012)
2. No LM = No Load Management beyond 2012
3. EE = Energy Efficiency Proposal (2013 and 2014 programs)
4. LM = Proposed Load Management through 2017
5. Res Light = Only Residential Lighting Program (2013 and 2014)

**STAFF EXHIBIT BEC-5RB**

2012 Energy Efficiency Program Filing
LOAD MANAGEMENT

| Year | Event Hours | MW Capacity | MWh Energy | Capacity Cost | Efficiency Rule Adder | Customer Incentives | $25 Sign-Up Bonus | Admin & Other | M&V | Annual Cost | Annual Cost Less Cust. Incentives/ Bonus | Avoided Cost Capacity | Avoided Cost Energy | Annual Benefit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 22 | 27.37 | - | $ 2,582,989 | | $ - | $ - | $ 313,651 | $ 67,480 | $ 2,964,120 | $ 2,964,120 | $ 114.83 | $ 0.07 | $ 3,801,037 |
| 2009 | 20 | 36.41 | 275 | $ 3,016,045 | | $ 1,103,855 | $ - | $ 147,632 | $ 147,886 | $ 4,415,918 | $ 3,312,063 | $ 114.83 | $ 0.08 | $ 5,080,305 |
| 2010 | 4 | 39.50 | - | $ 2,725,553 | | $ 1,159,023 | $ - | $ 129,133 | $ 101,147 | $ 4,095,952 | $ 2,936,289 | $ 114.83 | $ 0.09 | $ 5,400,467 |
| 2011 | 45 | 37.40 | 325 | $ 3,940,533 | | $ 1,492,891 | $ - | $ 329,821 | $ 65,705 | $ 5,869,031 | $ 4,376,139 | $ 114.83 | $ 0.06 | $ 5,216,714 |
| 2012 | 45 | 38.00 | 428 | $ 3,511,200 | | $ 950,000 | $ 457,928 | $ 329,821 | $ 65,785 | $ 5,354,735 | $ 3,946,807 | $ 114.83 | $ 0.07 | $ 5,316,932 |
| 2013 | 45 | 40.00 | 450 | $ 3,696,000 | | $ 1,000,000 | $ 403,003 | $ 301,013 | $ 13,125 | $ 5,413,141 | $ 4,010,138 | $ 114.83 | $ 0.07 | $ 5,591,113 |
| 2014 | 45 | 42.00 | 473 | $ 3,880,800 | | $ 1,050,000 | $ 364,599 | $ 273,729 | $ 13,125 | $ 5,572,353 | $ 4,157,654 | $ 114.83 | $ 0.07 | $ 5,871,474 |
| 2015 | 45 | 43.00 | 484 | $ 3,973,200 | | $ 1,075,000 | $ 310,362 | $ 273,250 | $ 13,125 | $ 5,644,947 | $ 4,259,585 | $ 114.83 | $ 0.08 | $ 6,015,101 |
| 2016 | 45 | 44.00 | 495 | $ 4,065,000 | | $ 1,100,000 | $ 271,566 | $ 273,250 | $ 13,125 | $ 5,722,592 | $ 4,351,987 | $ 114.83 | $ 0.08 | $ 6,155,782 |
| 2017 | 45 | 45.00 | 506 | $ 1,782,000 | | $ 1,125,000 | $ 271,566 | $ 273,250 | $ 13,125 | $ 3,464,952 | $ 2,068,385 | $ 114.83 | $ 0.08 | $ 6,296,444 |
| Total Costs | | | | $ 33,174,820 | | $ 10,056,409 | $ 2,069,125 | $ 2,704,637 | $ 513,719 | $ 48,518,700 | $ 36,393,156 | | | $ 54,825,429 |

Peak Saver

| Year | Event Hours | MW Capacity | MWh | Capacity Cost | Efficiency Rule Adder | Customer Incentives | N/A | Admin & Other | M&V | Annual Cost | Annual Cost Less Cust. Incentives | Avoided Cost Capacity | Avoided Cost Energy | Annual Benefit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 22 | 20.00 | - | $ 892,914 | | $ - | | $ 127,896 | $ 23,751 | $ 1,044,591 | $ 1,044,591 | $ 114.88 | $ 0.07 | $ 2,778,028 |
| 2009 | 20 | 17.00 | 369 | $ 604,877 | | $ 680,000 | | $ 83,518 | $ 49,345 | $ 1,507,740 | $ 827,740 | $ 114.88 | $ 0.08 | $ 2,353,000 |
| 2010 | 5 | 29.54 | - | $ 1,344,827 | | $ 1,185,600 | | $ 89,716 | $ 65,538 | $ 2,685,651 | $ 1,500,051 | $ 114.88 | $ 0.09 | $ 4,117,038 |
| 2011 | 45 | 19.50 | 720 | $ 1,169,250 | | $ 780,000 | | $ 77,800 | $ 10,055 | $ 2,037,105 | $ 1,257,105 | $ 114.88 | $ 0.36 | $ 2,756,827 |
| 2012 | 45 | 18.00 | 608 | $ 995,000 | | $ 720,000 | | $ 77,800 | $ 10,055 | $ 1,753,355 | $ 1,073,355 | $ 114.88 | $ 0.37 | $ 2,546,663 |
| 2013 | 45 | 20.00 | 675 | $ 1,095,000 | | $ 800,000 | | $ 111,869 | $ 13,125 | $ 2,019,994 | $ 1,219,994 | $ 114.88 | $ 0.37 | $ 2,530,628 |
| 2014 | 45 | 20.00 | 675 | $ 1,095,000 | | $ 800,000 | | $ 98,140 | $ 13,125 | $ 2,006,265 | $ 1,206,265 | $ 114.88 | $ 0.37 | $ 2,531,764 |
| 2015 | 45 | 20.00 | 675 | $ 1,095,000 | | $ 800,000 | | $ 96,636 | $ 13,125 | $ 2,004,761 | $ 1,204,761 | $ 114.88 | $ 0.08 | $ 2,537,138 |
| 2016 | 45 | 20.00 | 675 | $ 1,095,000 | | $ 800,000 | | $ 96,636 | $ 13,125 | $ 2,004,761 | $ 1,204,761 | $ 114.88 | $ 0.08 | $ 2,538,152 |
| 2017 | 45 | 20.00 | 675 | $ 1,095,000 | | $ 800,000 | | $ 96,636 | $ 13,125 | $ 2,004,761 | $ 1,204,761 | $ 114.88 | $ 0.08 | $ 2,539,223 |
| Total Costs | | | | | | $ 7,365,600 | | $ 956,646 | $ 224,398 | $ 19,109,012 | $ 11,743,412 | | | $ 28,769,260 |

Source: PNM Response to Staff Interrogatory 1-7

**BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

| | | |
|---|---|---|
| **IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL OF ELECTRIC ENERGY EFFICIENCY PROGRAMS AND PROGRAM COST COST TARIFF RIDER PURSUANT TO THE NEW MEXICO PUBLIC UTILITY AND EFFICIENT USE OF ENERGY ACTS,** | ) | **Case No. 12-00317-UT** |
| **PUBLIC SERVICE COMPANY OF NEW MEXICO.** | ) | |
| **Applicant.** | ) | |



**AFFIDAVIT OF BRUNO E. CARRARA**

**STATE OF NEW MEXICO** )
) **ss.**
**COUNTY OF SANTA FE** )

**I, BRUNO E. CARRARA, do hereby swear, depose and state as follows:**

I hereby attest that I have read the foregoing **PREPARED REBUTTTAL TESTIMONY OF BRUNO E. CARRARA,** and the statements contained therein are true and accurate to the best of my knowledge and information.

**BRUNO E. CARRARA**
6 Feb 2013
**DATE**

**SUBSCRIBED, SWORN TO AND ACKNOWLEDGED before me this** 6 **day of February 2013.**

**NOTARY PUBLIC**

**My Commission Expires:**
1-24-16

## BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

| | | |
|---|---|---|
| **IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR APPROVAL OF ELECTRIC ENERGY EFFICIENCY PROGRAMS AND PROGRAM COST TARIFF RIDER PURSUANT TO THE NEW MEXICO PUBLIC UTILITY AND EFFICIENT USE OF ENERGY ACTS,** | ) | **Case No. 12-00317-UT** |
| **PUBLIC SERVICE COMPANY OF NEW MEXICO,** | ) | |
| **APPLICANT.** | ) | |



## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the foregoing ***Rebuttal Testimony of Bruno E. Carrara,*** filed February 6, 2013, was sent by electronic mail to the individuals listed below.

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**DATED** this **6th** day of February, 2013.

**NEW MEXICO PUBLIC REGULATION COMMISSION**

**Elizabeth Ramirez, Legal Assistant**