BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 533	)	**Case No. 16-00276-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

DIRECT TESTIMONY

OF

JULIO C. AGUIRRE

December 7, 2016

NMPRC CASE NO. 16-00276-UT
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WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

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JULIO C. AGUIRRE
NMPRC CASE NO. 16-00276-UT

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Julio C. Aguirre. I am a Lead Pricing Analyst with Public Service Company of New Mexico ("PNM" or "Company"). My business address is 414 Silver SW, Mail Stop 1115, Albuquerque, NM 87102.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION AT PNM AND PROVIDE YOUR PROFESSIONAL WORK EXPERIENCE.

A. I have worked for PNM since November 2010 as a Pricing Analyst in the Pricing and Business Analytics Department, where I am responsible for providing rate design and pricing analysis in support of PNM corporate, regulatory, and marketing objectives. Prior to assuming my current responsibilities at PNM, I worked as an Economist for the Regulatory Operations Staff of the Public Utilities Commission of Nevada.

Q. WHAT ARE YOUR DUTIES AS PRICING ANALYST FOR PNM?

A. As a Lead Pricing Analyst I am responsible for planning, developing and implementing electric rates and lead the development of expert testimony regarding PNM's rate design.

Q. HAVE YOU PROVIDED TESTIMONY IN OTHER CASES BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION ("NMPRC" OR "COMMISSION")?

A. Yes. I previously filed testimony in support of various PNM applications before the NMPRC. I have also provided expert witness testimony before the Public Utilities Commission of Nevada in various regulatory proceedings. A statement of my experience and qualifications is attached as PNM Exhibit JCA-1.

Q. WHAT IS THE PRIMARY PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. In conjunction with PNM Witnesses Chan and Vogt, I help explain and support the Company's rate design proposals and proposed modifications to existing rates and rate structures included in PNM's rate case application. The primary purpose of my testimony is to support and explain the process PNM undertakes to design rates. This process includes the development of the "banding" PNM is proposing with the intent of mitigating significant rate increases for certain rate classes. I also explain and support use of the Company's Rate Design Model ("RD Model") as the final step in PNM's rate development for this case.

Q. PLEASE EXPLAIN HOW YOUR TESTIMONY IS PRESENTED AND PROVIDE AN OVERVIEW OF ALL ISSUES ADDRESSED IN YOUR TESTIMONY.

A. In terms of the rate design process, my testimony starts from the point where PNM Witness Vogt's testimony stopped. PNM Witness Vogt sponsors the Embedded Class Cost of Service Study ("ECCOSS Model"), which calculates PNM's fully allocated non-fuel revenue requirement for each rate class. The first section of my testimony addresses the next step in the rate design process, which is to take this fully allocated non-fuel revenue requirement and apply banding to mitigate the increases that result from applying the fully allocated revenue requirements to certain rate classes. As part of the banding process, I also establish each rate class' non-fuel revenue deficiency after banding, which is set forth in Table JCA-1. Next, my testimony sets forth the results that the Company's proposed banding has on the each rate class' resulting relative rate of return. Relative rate of return provides a picture of the effect of banding on each rate class' status as a class that is subsidizing or being subsidized.

After the allocated revenue requirement is banded, PNM must apply the RD Model to convert each rate class' Test Period revenue requirement after banding into individual rate components. My testimony discusses the RD Model functions, as well as the principal policy guidelines PNM uses to design its rates. My testimony then outlines the Company's proposed modifications to residential rate design. In particular, I support PNM's long-term goal to work with stakeholders to design a residential rate structure that will more effectively address growing residential peak demand, and the Company's proposed first step in this case to flatten its inclining block rates in support of this long-term goal. My testimony discusses PNM's revisions to its voltage class adjustment factors as one additional piece of rate design and how these factors are applied to the Fuel and Purchased Power Costs Adjustment Clause ("FPPCAC"). The FPPCAC Factors, also referred to as fuel rates, are calculated for informational purposes only.[1]

After discussing the proposed rate design, my testimony next outlines the impact of PNM's proposed rate design on its rate classes. I separately address each rate class with two-part and three-part tariffs. I also explain and support PNM's proposed new Rider 48 – Lost Contribution to Fixed Cost ("LCFC"), which is the Company's proposed mechanism to remove energy efficiency disincentives. Following this discussion, my testimony addresses the Enhancements to the Rate 20 – Integrated System Streetlighting and Floodlighting Service ("Rate 20 – Streetlighting" or "Streetlighting") tariff in order to address certain compliance items from NMPRC Case No. 15-00261-UT ("2015 Rate Case"). The testimony also supports the overall rate design for Rate 20 – Streetlighting and Rate 6 – Private Area Lighting. The testimony concludes by discussing other miscellaneous tariff changes.

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[1] PNM collects all non-renewable fuel and purchased power through the FPPCAC Factor and renewable energy costs through the Renewable Energy Rider.

Q. WHICH RULE 530 SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring the following Rule 530 Schedules:

- O-1, Total revenue requirements by rate classification for the Base Period and Test Period.
- O-2, Proof of Revenue analysis: Test Year Period.
- O-3, Comparison of rates for service under the present and proposed schedules.
- O-4, Explanation of proposed changes to existing rate schedules.

Q. ARE ANY OF YOUR EXHIBITS OR THE RULE 530 SCHEDULES THAT YOU SPONSOR BEING PROVIDED ELECTRONICALLY?

A. Yes. The following exhibits also are being provided in executable electronic format on a DVD-ROM labeled "2016 Electric Rate Case Filing Case No. 16-00276-UT Cost of Service Model, Embedded Class Cost of Service and Rate Design including Workpapers":

- The final revenue allocation to each customer class before and after banding (PNM Exhibit JCA-3).
- The RD Model for Non-Lighting Classes (PNM Exhibit JCA-4).
- Calculation of Fuel Rates (PNM Exhibit JCA-5).
- Derivation of the Factors Used for the Assignment of Demand Production Costs to Seasons (PNM Exhibit JCA-7).
- The RD Model for Streetlighting Rate 20 (PNM Exhibit JCA-12).

- The RD Model for Private Lighting Rate 6 (PNM Exhibit JCA-14).

The following Rule 530 Schedules are linked to the ECCOSS Model or the Rate Design Model, and therefore, are being filed in executable electronic format on the same DVD-ROM as the ECCOSS Model: Rule 530 Schedules O-1, O-2, and O-3. Rule 530 Schedule O-4 will be provided electronically in PDF format.

Q. DOES THE RATE DESIGN MODEL HAVE THE SAME FUNCTIONALITY AND FORMAT AS WAS FILED IN THE 2015 RATE CASE?

A. Yes. The Rate Design Model, being filed in executable electronic format, has the same functionality as was provided by PNM in the 2015 Rate Case. The Hearing Examiner and Commission used this model for the final rate design in the 2015 Rate Case and to calculate the rates that were ultimately approved in that case.

II. PNM'S PROPOSED BANDING

Q. IS PNM PROPOSING NEW RATES THAT ARE BASED UPON THE FULLY ALLOCATED REVENUE REQUIREMENTS RESULTING FROM THE ECCOSS MODEL?

A. No. Consistent with the approach adopted by the Commission in the 2015 Rate Case, PNM proposes to apply a banding process to mitigate the increases that result from applying the fully allocated revenue requirements to the residential,[2] irrigation,[3] water and sewage[4] and large power service >=3,000kW[5] classes. This banding process establishes an upper and lower limit to revenue increases for each rate class based on the gradualism principle.

Q. HOW DOES THE PROPOSED BANDING FOR THIS RATE CASE COMPARE WITH THE BANDING METHODOLOGY APPLIED BY THE COMMISSION IN THE 2015 RATE CASE?

A. PNM's proposed banding methodology for this rate case is consistent with the methodology applied by the Hearing Examiner in the Corrected Recommended Decision ("CRD") and the Commission in the Final Order for the 2015 Rate Case.[6] In addition, the Commission's Final Order in the 2015 Rate Case resulted in PNM recovering all of its fuel and purchased power costs through its Rider No. 23, the FPPCAC Factor, and no such costs through its base rates. Because 100% of fuel and purchased power costs are recovered through the FPPCAC Factor, banding is applied only on the basis of the Company's non-fuel revenue deficiency in this case.

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[2] The residential rate class includes Rates 1A – Residential Service ("Rate 1A – Residential") and Rate 1B – Residential Service Time-of-Use ("Rate 1B – Residential TOU") (collectively "Rate 1A/1B – Residential").
[3] The irrigation rate class includes Rate 10A – Irrigation Service ("Rate 10A – Irrigation") and Rate 10B – Irrigation Service Time-of-Use ("Rate 10B – Irrigation TOU") (collectively "Rates 10A/10B – Irrigation").
[4] The water and sewage class is served under Rate 11B – Water and Sewage Pumping Time-of-Use ("Rate 11B – Water and Sewage").
[5] This large power rate class is served under Rate 35B – Large Power Service >=3,000kW ("Rate 35B").
[6] For example, the banding process is consistent with the methodology used by the Hearing Examiner given that it first accounts for the credits or adjustments to class revenue and then applies the upper and lower bands to the rate classes.

Q. IS PNM REQUESTING IMPLEMENTATION OF THE FULL PROPOSED RATE INCREASE IN THIS CASE AS OF JANUARY 1, 2018?

A. Yes. The rates proposed in PNM's Advice Notice for this case reflect implementation of the full rate increase supported by PNM's rate case filing as of January 1, 2018. As explained by PNM Witness Ortiz, if the Commission approves the full rate increase requested by PNM, the Company has prepared rates that reflect a phased-in implementation schedule for its requested increase. The schedule would implement the rate changes over two phases. The first phase would be effective on January 1, 2018 ("Phase I"), and the second phase would be effective on January 1, 2019 ("Phase II"). PNM Exhibit JCA-4 provides the derivation of PNM's proposed rates at the requested full revenue requirement, which is equivalent to the Phase II implementation. PNM Exhibit JCA-16 shows the derivation of the Phase I rates. To reflect the alternatively proposed phase-in, PNM has included sample tariff sheets that reflect both the full rate increase as requested in this case, or Phase II, as well as the proposed rate increase for Phase I, in its Advice Notice filing that is an exhibit to the rate application.

Q. HOW DOES PNM PROPOSE TO STRUCTURE THE ALTERNATIVE, PHASED-IN RATE INCREASE?

A. PNM proposes that Phase I would recover $50 million of the total non-fuel revenue deficiency, $99.2 million, which results in a 7.2% increase in non-fuel revenues. Phase II would recover the total revenue deficiency, $99.2 million, which includes the remaining revenue deficiency of $49.2 million. Phase II results in an additional 7.1% non-fuel revenue increase.

Q. HOW DID PNM CALCULATE PHASE I RATES?

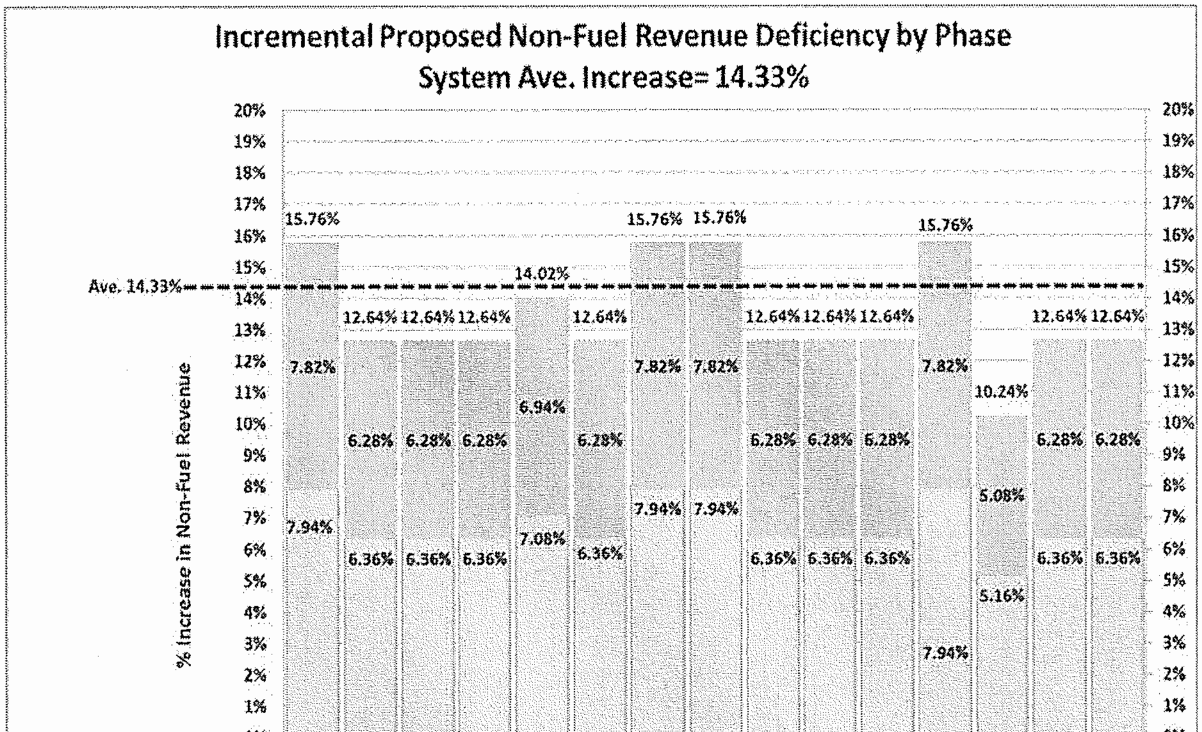
A. PNM's proposed rates for Phase I were scaled-down from the rates at the full revenue requirements to arrive at the $50 million Phase I revenue increase. As noted above, PNM Exhibit JCA-16 shows the derivation of the Phase I rates.

Q. WHAT BANDS DOES PNM PROPOSE TO APPLY TO THE FULLY ALLOCATED NON-FUEL REVENUE REQUIREMENT IN ORDER TO MITIGATE THE RATE INCREASE FOR CERTAIN CUSTOMER CLASSES?

A. PNM proposes to apply an upper band of 110% and a lower band of 88% to the system non-fuel revenue requirement increase. For the full, proposed revenue requirement, the upper band means that no rate schedule will see a non-fuel revenue increase higher than 15.76%. The lower band implies no rate schedule will see a non-fuel revenue increase less than 12.64%. The upper band as applied in Phase I means no rate schedule will see a non-fuel revenue increase higher than 7.94%. The lower band for Phase I implies no rate schedule will see a non-fuel revenue increase less than 6.36%. Figure JCA-1 below shows the proposed percentage increase for each rate class after banding.

For Rate 36B – Special Service Rate – Renewable Energy Resources ("Rate 36B – Special Renewable Rate" or "Rate 36B") and Rate 4B - Large Power Service Time-of-Use ("Rate 4B – Large Power"), PNM is allocating 100% of the costs to these classes as dictated by the ECCOSS Model.

Figure JCA-1



	Res. 1A/1B	Small Power 2A/2B	General Power 3B	General Power 3C	Large Power 4B	Large Service >= 8,000k W 5B	Irrig. 10A/ 10B	Water & Sewage 11B	Univer. 15B	Manuf. 30B	Station Power 33B	Large Power Service >=3,000 kW 35B	Special Service Ren. Energy Res. 36B*	Private Lighting 6	Street Lighting 20
% Change Phase II	7.82%	6.28%	6.28%	6.28%	6.94%	6.28%	7.82%	7.82%	6.28%	6.28%	6.28%	7.82%	5.08%	6.28%	6.28%
% Change Phase I	7.94%	6.36%	6.36%	6.36%	7.08%	6.36%	7.94%	7.94%	6.36%	6.36%	6.36%	7.94%	5.16%	6.36%	6.36%
Total Increase	15.76%	12.64%	12.64%	12.64%	14.02%	12.64%	15.76%	15.76%	12.64%	12.64%	12.64%	15.76%	10.24%	12.64%	12.64%

Q. IS PNM APPLYING ITS BANDING PROCESS TO RATES 4B AND 36B?

A. No. Rate 4B's proposed revenue requirement increase, which is fully cost-based, is within the upper and lower bands. As such, it unnecessary to apply any band to this rate class.[7] Rate 36B's proposed revenue requirement increase also is fully cost-based. To recognize the economic development benefits that this new customer is bringing to the state, PNM is not applying the lower band to this customer class. PNM Witness Vogt's testimony demonstrates that no other customer class is adversely impacted by setting Rate 36B's revenue requirement increase at cost-based levels.

Q. WHAT IS THE RATIONALE FOR PNM'S PROPOSED UPPER AND LOWER BANDS?

A. PNM's ultimate rate design policy objective is to align cost causation with cost recovery. However, the Commission has long recognized the principle of gradualism, which requires PNM to mitigate large rate increases for certain rate classes. Starting with the 2015 Rate Case, PNM made some progress toward more transparent and cost-based rates that reflect cost causation. As also discussed by PNM Witness Chan, PNM is proposing in this case to continue to balance the need for true cost responsibility among the rate classes with the potential disparate impacts that would result from a fully allocated cost-based

[7] Transitional Rider No. 8 –Incremental Interruptible Power Rate, which is discussed below, is applied to Rate 4B.

revenue requirement for some classes. PNM's proposed upper and lower bands ultimately reflect this balance.

Q. HOW DO PNM'S PROPOSED UPPER AND LOWER BANDS MITIGATE THE RATE IMPACT ON CERTAIN RATE CLASSES?

A. PNM's proposed upper band of 110% mitigates the rate impacts for those rate classes that would otherwise experience a significant rate increase as the result of this case. As noted by PNM Witness Vogt, the ECCOSS Model allocates approximately $409 million in non-fuel revenue requirement to the residential rate class before banding. After banding, PNM is allocating $384.5 million in non-fuel revenue requirement to the residential rate class, which means that approximately $24.5 million must be allocated to other rate classes.[8] The proposed lower band of 88% represents the shift of non-fuel revenue requirement responsibility to other rate classes that is necessary to balance the rate impact mitigation accomplished via the upper band.

To balance the subsidies that result from banding, PNM typically requires that subsidized classes experience increases above the system average while subsidizing classes experience increases that are below the system average increase. More specifically, the rate classes that are being subsidized were capped

[8] This subsidy for the residential customer class in this rate case is lower than the subsidy for the residential rate class that was allocated to other customer classes in the 2015 Rate Case. The resulting subsidy in the 2015 Rate Case as a result of the Final Order was approximately $26 million. As noted above, in this case the subsidy is $24.5 million.

at the upper band of 15.76%, above the system average increase of 14.33%. On the other hand, the classes that are being allocated additional revenue requirements to accomplish the proposed rate mitigation for the subsidized rate classes were banded below the system average increase at 12.64%.

Q. WHAT ARE THE REVENUE DEFICIENCIES BY RATE CLASS BEFORE AND AFTER BANDING?

A. Table JCA-1 shows the non-fuel revenue deficiencies before and after banding. The non-fuel revenue deficiency for the residential class is approximately $76.8 million before banding, which is approximately 77% of the total non-fuel revenue deficiency. After banding, this deficiency is reduced to $52.3 million.

Table JCA-1
Non-Fuel Revenue Deficiency by Rate Class[9]

Rate Class	Total Allocated Revenue Defficiency Before Banding	After Banding
1A/1B - Residential	$ 76,806,789	$ 52,355,833
2A/2B - Small Power	$ 6,906,209	$ 12,374,741
3B - General Power	$ 2,213,784	$ 15,541,980
3C - General Power (Low Load Factor)	$ (5,836,927)	$ 2,877,121
4B - Large Power	$ 9,330,702	$ 9,355,619
5B - Large Service for Customers >=8,000kW	$ (73,151)	$ 499,282
10A/10B - Irrigation	$ 717,765	$ 283,500
11B - Wtr/Swg Pumping	$ 2,793,897	$ 1,318,266
15B - Universities 115 kV	$ (100,223)	$ 479,421
30B - Manufacturing (30 MW)	$ 3,263,428	$ 1,792,055
33B - Station Service	$ (27,735)	$ 21,942
35B - Large Power >=3,000kW	$ 4,240,006	$ 919,874
36B - Special Service -Renw. Energy Res.	$ 220,384	$ 220,384
6 - Private Lighting	$ (1,012,075)	$ 337,232
20 - Streetlighting	$ (192,977)	$ 872,626
Tariff Class Totals	$ 99,249,875	$ 99,249,875

Q. WHAT IS A RELATIVE RATE OF RETURN AND WHAT INFORMATION DOES IT PROVIDE?

A. A relative rate of return is a measure of how close each rate class is to a fully cost-based revenue allocation. A relative rate of return of 1.0 means that a rate class is responsible for all the costs that the Company incurs to serve that rate class. Rate classes with a relative rate of return greater than 1.0 subsidize other rate classes that have a relative rate of return below 1.0. Rate classes with a relative rate of return lower than 1.0 are being subsidized by the rate classes with a rate of return

[9] PNM Witness Vogt's testimony shows slightly different revenue deficiency numbers before banding, which is a result of the Rate 36B Contribution to Production credit noted in his testimony. Given that the ECCOSS Model as filed did not account for the Rate 36B Contribution to Production Credit and my models do account for this credit, the deficiency numbers indicate slight differences.

above 1.0. To attain a true cost of service for the entire system, or rate unity, all rate classes should have a relative rate of return of 1.0.

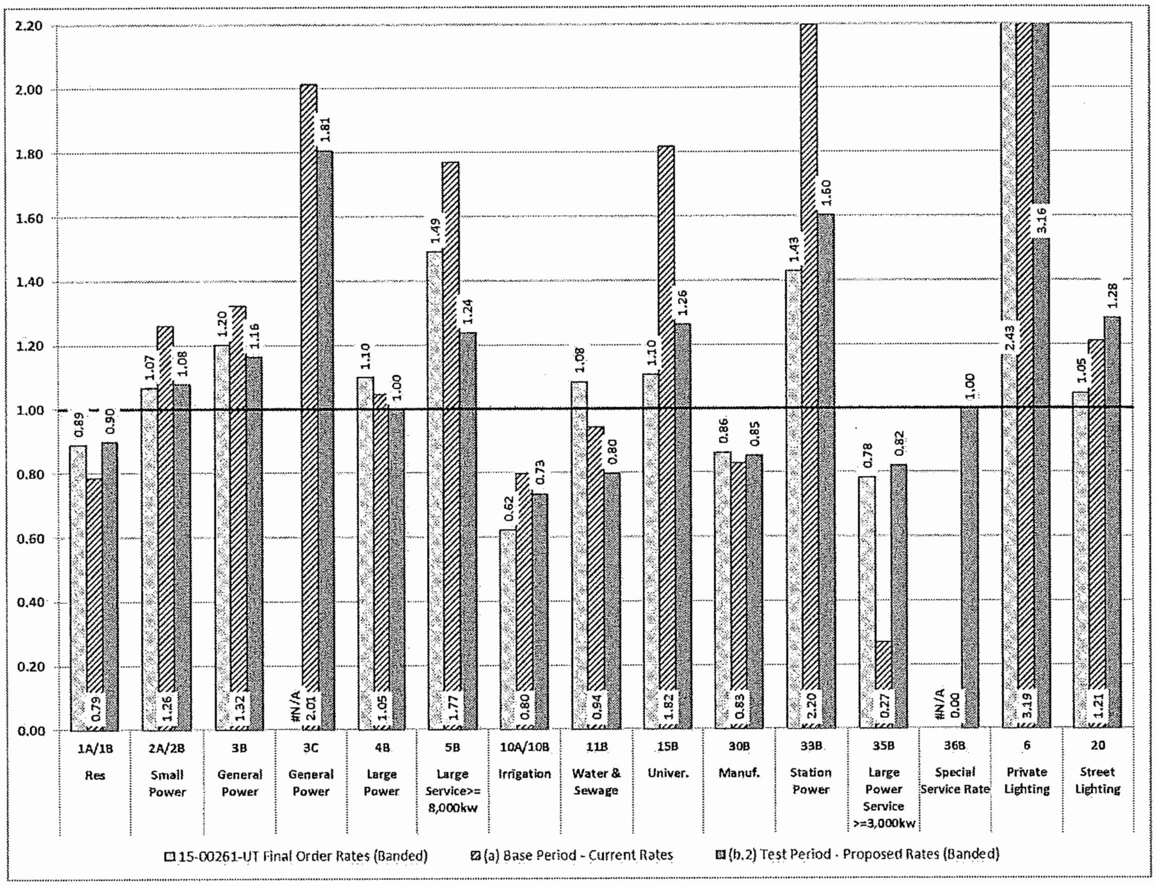
Q. WHAT ARE THE RESULTS OF THE COMPANY'S BANDING IN TERMS OF EACH CLASS' RESULTING RELATIVE RATE OF RETURN?

A. The calculation of the relative rate of return by rate class provides a picture of the effect of banding on each rate class' status as a subsidizing class or a class that is being subsidized. Figure JCA-2 below shows the resulting relative rates of return for each rate class after banding.[10] For comparison purposes, PNM is including the relative rates of return resulting from the approved rates in the 2015 Rate Case.

Based on PNM's proposed banding in this case, five classes are moving closer to the unity rate of return, reducing the overall interclass subsidization when compared to the approved rates in the 2015 Rate Case. These classes are: Rate 1A/1B – Residential; Rate 3B – General Power Service Time-of-Use ("Rate 3B – General Power"); Rate 5B – Large Service>=8,000 kW; Rate 10A/10B – Irrigation; and Rate 35B. Two classes are set at unity of return, Rate 4B – Large Power and the recently approved Rate 36B – Special Renewable Rate.

[10] The relative rate of return calculations are based on results from Rule 530 Schedule N-1, which is sponsored by PNM Witness Vogt.

Figure JCA-2
Comparison of Relative Rates of Return by Rate Class



Q. IS PNM ACCOUNTING FOR ANY REVENUE CREDITS BEFORE THE BANDING PROCESS?

A. Yes. A Contribution to Production charge is being assessed on the Rate 36B – Special Renewable Rate customer, as approved by the NMPRC in Case No. 16-00191-UT. Using the Contribution to Production charge of $0.0231074 per kWh, a credit is calculated by multiplying this charge by the energy projected to be supplied to this customer from PNM's generation resources during the Test Period, totaling $877,302. The revenue requirements associated with this credit were apportioned to all customer classes based on the 3-Summer/1-Winter coincident peak ("3S1WCP") allocator used for generation demand costs before banding is conducted. PNM Witness Vogt provides evidence for the Commission to determine that the Rate 36B – Special Renewable Rate customer is not being subsidized by any other rate class during the Test Period.

III. PNM'S RATE DESIGN MODEL

Q. WHAT IS THE PRIMARY FUNCTION OF THE RD MODEL?

A. The primary function of the RD Model, attached as PNM Exhibit JCA-4, is to convert the Test Period revenue requirement for each rate class into the individual rate components found in PNM's tariffs. As an example, for PNM to implement its proposed rate design, it must determine the rates and amount of revenue to be collected from residential customers in each inclining block rate, as well as the rates and revenue to be collected for on-peak and off-peak usage from Time-of-Use ("TOU") customers. The RD Model derives each of these rate components, ensuring that the proposed rates are fair and reasonable and allow an opportunity for the Company to recover the reasonable costs of providing utility service to its various rate classes.

Q. HAS PNM PROVIDED A FUNCTIONAL ELECTRONIC VERSION OF PNM'S RD MODEL?

A. Yes. Parties can make adjustments to the Company's proposed rate design in the RD Model. PNM's RD Model is functionally linked to the ECCOSS Model (PNM Exhibit SAV-4), the Test Period Billing Determinants (PNM Exhibit SC-5) and the final revenue requirements by rate class after banding (PNM Exhibit JCA-3). This means that a user will be able to modify the key inputs to the RD Model and determine cost-based rates, which are calculated within the RD Model (please refer to Columns (C)-(D) within each individual tab in PNM Exhibit JCA-4). However, modifications to the key inputs to the RD Model will not automatically result in rates that would generate PNM's requested (or adjusted) revenue requirements for the Test Period. Thus, any modification to the costs included in the ECCOSS Model, the determinants included in the Test Period Billing Determinants or the banding criteria will necessarily require adjustments to the proposed rates in the RD Model to arrive at the target revenue requirement by rate class.

Q. WHAT ARE THE RATE COMPONENTS CALCULATED BY THE RD MODEL?

A. PNM has four different rate components in its tariffs that are calculated by the RD Model, which are: (1) customer charges (including meter charges); (2) demand charges (where applicable, including reactive kilovolt amperes charges or "RkVA");[11] (3) volumetric charges; and (4) facilities charges (where applicable).

Q. HOW DOES PNM DETERMINE THE TEST PERIOD REVENUE REQUIREMENTS THAT MUST BE COLLECTED FROM EACH RATE CLASS PRIOR TO APPLYING THE RD MODEL?

A. The Test Period non-fuel revenue requirement for each rate class is an output of the ECCOSS Model. The Test Period non-fuel revenue requirement as calculated by the ECCOSS Model is then banded to mitigate significant rate increases for certain classes, and to the extent possible, to ensure the Company's resulting rate design supports a reasonable and moderate step toward full class cost recovery. It is this final amount – the Test Period revenue requirement by rate class after banding is applied – that is used in the RD Model to calculate each individual rate.

Q. HOW IS THE REVENUE REQUIREMENT BY RATE CLASS AFTER BANDING INPUT INTO THE RD MODEL?

A. The non-fuel revenue requirement by rate class from the ECCOSS Model (after banding) is broken down into three different cost classifications and input into the RD Model in accordance with underlying cost causation principles: (1) customer-

[11] RkVA is a charge designed to ensure customers maintain reasonable power factors per the terms of the applicable tariff.

related revenue; (2) demand-related revenue; and (3) non-fuel energy-related revenue.

The first two cost classifications listed above are associated with fixed costs in that the underlying costs associated with these classifications do not vary with energy usage (kWh). As explained later in my testimony, PNM proposes in this case to increase the recovery of the fixed costs through the fixed monthly customer and demand charges, when applicable and feasible. The third cost classification listed above represents non-fuel variable costs that PNM proposes to recover through the applicable volumetric (i.e., per kWh) rates within each rate class. I discuss each of the different types of rates calculated by the RD Model below.

Q. DOES THE RD MODEL INCLUDE ANY FUEL COSTS CALCULATIONS?

A. No. Due to the implementation of "Method A"[12] and recovery of 100% of fuel and purchased power costs through the FPPCAC Factor as a result of the 2015 Rate Case, PNM is not including any fuel costs in the RD Model. However, PNM does use projected fuel costs to demonstrate overall rate impacts and to comply with Rule 530 requirements. Specifically, fuel costs are included in the calculation of revenue requirements shown in Rule 530 Schedule O-1.

[12] Method A is explained in the CRD at 278, Decretal Paragraph H.

Additionally, PNM Exhibit JCA-10 includes fuel projections for illustrative purposes only to show a full revenue impact analysis for each customer class.

Q. ARE ANY OTHER INPUTS REQUIRED TO CONVERT THE TEST PERIOD REVENUE REQUIREMENTS FOR EACH RATE CLASS INTO RATES?

A. Yes, the other key input in the RD Model is the Test Period Billing Determinants (PNM Exhibit SC-5), which calculates the billing determinants by rate schedule for the Test Period. As discussed above, the RD Model determines how much revenue must be collected from each individual rate component in order for the Company to collect its Test Period revenue requirement. To convert the Test Period revenue requirement from the ECCOSS Model (after banding) into these individual rate components, PNM applies the various billing determinants by rate schedule for the Test Period (e.g., number of customers, summer and non-summer on-peak and off-peak kWh) to this Test Period revenue requirement.

IV. PNM'S GUIDELINES FOR RATE DESIGN

Q. FOR THIS RATE CASE, WHAT ARE THE GUIDING PRINCIPLES FOR PNM'S RATE DESIGN?

A. As discussed in the testimony of PNM Witness Chan, PNM is continuing with its efforts that began in the 2015 Rate Case to improve on the Company's outdated rate design so that rates will more accurately reflect the costs the Company incurs to serve its customers by rate class. In particular, PNM is seeking additional modifications to its rates to not only more accurately reflect the Company's cost of service, but also to balance the ultimate rate class impacts in recognition of the long-accepted principle of gradualism. It would not be appropriate to move toward fully cost-based rates in this rate case given that significant rate impacts must be avoided for certain rate classes. Nonetheless, the Company is putting forth rate design proposals that will continue to maintain or improve the general alignment of rates with cost causation.

Q. PLEASE EXPLAIN HOW PNM CALCULATES ITS PROPOSED CUSTOMER CHARGES FOR THIS RATE CASE.

A. PNM proposes to recover all customer-related costs in the customer charge for all retail classes with the exception of Rate 10A/10B – Irrigation.[13] Customer-related costs include expenses related to customer service lines, meters, meter reading activities, bill processing and other customer-related activities. PNM's proposed customer charges for all classes except Rate 10A/10B – Irrigation are cost-based and are not impacted by the banding process, which helps reduce intra-class subsidization within each rate class, particularly for classes under a two-part tariff (i.e., rates containing just a customer charge and an energy component). For example, if a significant portion of customer-related costs are allocated to volumetric rates, a customer with higher than average usage would be

[13] For Rate 10A/10B – Irrigation, PNM proposes to recover approximately 30 percent of the customer-related costs in the customer charge. I discuss this in more detail below.

contributing a greater share of customer-related costs, effectively subsidizing customers with lower than average usage whose consumption will not cover the customer's allocated share of customer-related costs.

Q. HOW DOES PNM PROPOSE TO CALCULATE THE CUSTOMER CHARGES UNDER ITS PROPOSED PHASED-IN REVENUE REQUIREMENT INCREASE?

A. As noted above, the customer charges for all retail classes, except Rates 10A/10B – Irrigation, are proposed to be set at the cost-based level as dictated by the ECCOSS Model. For Phase I, the proposed customer charges are adjusted downward from their full, cost-based level to reflect the Phase I revenue increase of $50 million, and then are set at the cost-based charge in Phase II with the exception of Rate 1A and Rate 1B. In the interest of gradualism, the customer charge for Rate 1A – Residential is proposed as $10.39 for Phase I, which includes only 50% of the total requested customer charge increase with an additional increase in Phase II to reach $13.77.[14] With regard to Rate 1B – Residential TOU, PNM proposes that the customer charge remain at its current level for both phases. Given that PNM is not proposing to modify the customer charge for Rate 1B – Residential TOU in this rate case, it would confuse customers to scale down the customer charge in Phase I, only to increase it to back to its original level in Phase II.

[14] The Phase I increase is slated to increase rates slightly above 50%.

Q. WHY IS IT IMPORTANT FOR THE CUSTOMER CHARGE TO BE SET AT A LEVEL THAT RECOVERS ALL CUSTOMER-RELATED COSTS?

A. From a rate design perspective, it is appropriate to recover these customer-related costs through a fixed monthly charge.[15] Costs for meters, billing, meter reading, bill processing, customer service and other customer-related activities are constant for every customer in a given rate class, and those costs do not change with sales and delivery of electricity. For example, regardless of the amount of electricity a customer uses, PNM has to install a meter, read the meter monthly, set up an account in the billing system, process a bill monthly, and have customer service available to assist the customer when the need arises. Table JCA-2 provides a breakdown of the residential customer-specific costs PNM incurs per month and per residential customer based on the full, proposed revenue requirement.

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[15] Customer-related costs are one category of fixed costs. Other categories of fixed costs are discussed in Section VIII.

Table JCA-2
Residential Customer-Related Costs
Per Customer/Per Month

Customer Service	$1.83
Customer Meter	$2.76
Customer Meter Reading	$2.01
Customer Billing and Processing	$3.74
Other Customer-Related Activities[16]	$3.44
TOTAL	**$13.77**

Q. IS IT PARTICULARLY IMPORTANT FOR PNM TO COLLECT ALL OF ITS RESIDENTIAL CLASS CUSTOMER-RELATED COSTS FROM RESIDENTIAL CUSTOMERS?

A. Yes. An increased customer charge for the residential class is an important first step to addressing the subsidy for this rate class. The non-fuel revenue deficiency for the residential class is approximately $76.8 million of PNM's total revenue deficiency of $99.2 million. No other single rate class has anywhere near this level of revenue deficiency. Moreover, currently the residential customer charge recovers only approximately 12% of this class' fixed costs. The residential class' rate design therefore recovers a majority of costs through volumetric charges. The proposed increase to the customer charge is a small, reasonable, yet

[16] Other customer-related activities include costs from the following Federal Energy Regulatory Commission ("FERC") accounts: 901.0 (Supervision – Customer Accounts); 906.0 (Customer Service/Information Expenses); 908.0 (Customers Assistance Expenses); and 912.0 (Demo and Selling Expenses).

significant step toward improved fixed cost recovery from this rate class and may alleviate further growth in the subsidy in the future.

Q. DOES INCREASING THE RESIDENTIAL CUSTOMER CHARGE MEAN THAT PNM NECESSARILY WILL RECOVER ALL OF ITS FIXED COSTS ASSOCIATED WITH SERVING THESE CUSTOMERS?

A. No. In addition to the customer-related costs detailed above, PNM incurs other fixed costs to serve residential customers that are currently allocated as demand-related, namely primary and secondary distribution costs, transmission costs, substation costs and generation-demand costs. Because the residential customers are charged under a two-part tariff (with no demand rate), the demand-related costs are recovered through this class' volumetric rate. In fact, approximately 88% of fixed costs are recovered through the volumetric rate.

Q. ABSENT ANY OTHER RECOVERY MECHANISM, WHAT WOULD THE MONTHLY CUSTOMER CHARGE BE FOR THE RESIDENTIAL CLASS IF ALL THESE OTHER FIXED COSTS WERE INCLUDED?

A. If PNM included these other fixed, demand-related costs in the residential customer charge, the Company would have to collect an additional \$51.24 from residential customers, which would result in a total customer charge of approximately \$65.01. While PNM's proposed customer charge of \$13.77 per month[17] is a significant increase from the current monthly charge of $7.00, it still represents only 21% of the total demand and customer-related fixed costs that PNM incurs to serve residential customers. Together with banding, PNM is taking moderate but necessary steps toward aligning rates with the actual costs to serve residential customers.

Q. WILL RATE 1A – RESIDENTIAL CUSTOMERS HAVE THE ABILITY TO CONTROL THEIR ENERGY USAGE AND BILLS, EVEN WITH AN INCREASE IN THE CUSTOMER CHARGE?

A. Yes. Even with the proposed monthly customer charge and certain modifications to the inclining block rates proposed in this case, the predominant portion of a customer's bill remains the volumetric energy charge. Residential customers still maintain control of their electric bill, and can directly influence their monthly expenses by managing energy consumption and taking advantage of opportunities aimed at reducing their energy usage through energy efficiency programs or conservation. Under PNM's proposed rates, residential customers using 600 kWh per month still control approximately 80% of their bill through their volumetric energy charges (non-fuel only). Furthermore, customers using 450 kWh per month still control over 73% of their bill, while customers using 200 kWh per month have control over 55% of their monthly electric bill.

[17] Under the alternative phase-in schedule proposed by PNM for its full revenue requirement, the customer charge for Rate 1A – Residential will be $10.39 per month in 2018 and $13.77 in 2019.

Q. DID THE HEARING EXAMINER IN THE 2015 RATE CASE FIND THAT THERE IS A LINK BETWEEN THE CUSTOMER CHARGE AND ENERGY EFFICIENT BEHAVIOR?

A. No. Page 226 of the CRD in the 2015 Rate Case specifically found that no PNM-specific, statewide or nationwide evidence demonstrated a link between the level of the customer charge and participation in energy efficiency programs.

Q. DOES AN INCREASED RESIDENTIAL CUSTOMER CHARGE NECESSARILY IMPACT LOW INCOME CUSTOMERS?

A. No. As a starting point, when parties make arguments that low income customers are adversely affected by a higher customer charge, they universally assume that low income customers are synonymous with low usage customers. This assumption has not been proven in recent cases. Also, as discussed by PNM Witness Chan, the Company's recent analysis indicates there is no relationship between income and electric usage.

Q. WHAT TYPE OF PRICE SIGNAL IS SENT TO CUSTOMERS AS A RESULT OF INCREASING THE CUSTOMER CHARGE TO RECOVER MORE CUSTOMER-RELATED COSTS?

A. A customer charge that better approximates the total customer-related costs provides a more accurate price signal and offers greater transparency to customers about the fixed costs that PNM incurs to connect them to the system, regardless of the amount of energy consumed. Improved price signals can translate into more economically efficient energy usage. This relationship was recognized in the 2015 Rate Case CRD at page 225, which stated that "[a]s more customer-related costs are recovered through the customer charge, a more accurate price signal is sent to customers of the cost to have service regardless of how much energy is used."

Q. PLEASE EXPLAIN PNM'S PROPOSAL REGARDING DEMAND CHARGES.

A. The general goal in calculating demand charges through the RD Model is to move closer to a demand charge that fully reflects all of the capacity-related costs. PNM also has an interest in designing demand charges that send accurate price signals to its customers about how their peak load affects their electricity bill. These price signals will foster economically efficient energy usage, thus incentivizing system use optimization and promoting higher load factor use, thereby lowering costs to all customers.

However, there are reasons why PNM should not design a demand charge that collects all capacity-related costs for all customer classes, including consideration of: (1) the rate impacts for customers within each rate class with different load factors; and (2) preserving the underlying integrity of PNM's existing rate schedules by preventing unintended customer migration.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY INTEGRITY OF EXISTING RATE SCHEDULES.

A. The Company's existing rate schedules are based on a predetermined set of criteria, which are primarily a function of customer usage patterns and/or customer end-use applications. While each customer is entitled to choose the rate schedule that is most advantageous based on his or her usage patterns and circumstances, if there are extreme rate impacts within customer classes or customers can indiscriminately switch rate schedules, such circumstances can fundamentally confuse customers, change the class characteristics and adversely affect adequate cost recovery from that rate class.

Q. HOW HAS THE COMPANY CALCULATED THE PROPOSED DEMAND CHARGES?

A. For all three-part rate classes, PNM proposes to increase the amount of demand-related fixed costs being recovered through demand charges. These costs include fixed costs the Company incurs for production, transmission, substations and primary/secondary distribution. PNM Exhibit JCA-6 provides a summary of PNM's current and proposed demand charges.

Q. HOW ARE DEMAND CHARGES AFFECTED BY THE BANDING PROCESS PROPOSED BY PNM IN THIS CASE?

A. Even though the application of the banding process modifies the amount of demand-related costs that are ultimately being allocated to each rate class, PNM is limiting its proposed demand rates to the lower of the cost-based level or the cost level allocated to each rate class after banding. This means that for classes receiving a subsidy through the banding process, PNM is not proposing a demand charge higher than what is indicated after the banding is applied. For the rate classes not receiving a subsidy, PNM is capping the demand charges at the cost-based level, resulting in true cost-based demand charges for those rate classes. This approach is consistent with the steps PNM took in its 2015 Rate Case.

Q. PLEASE EXPLAIN HOW PNM DETERMINED THE SPLIT OF DEMAND-RELATED REVENUE REQUIREMENT BETWEEN SEASONS.

A. Consistent with the methodology approved in the 2015 Rate Case, PNM assigns demand-related revenue requirements to the existing two seasons – summer (June, July and August) and non-summer (all other months) – using a base, intermediate and peak-period assignment methodology. This method mimics the patterns of a load duration curve and approximates the utilization of system resources to meet peak loads for the defined season periods. PNM only used this methodology to assign its demand production costs. All other demand-related costs are considered non-seasonal in nature and, thus, were assigned proportionally based on the corresponding annual billing determinants within each applicable rate schedule.

PNM Exhibit JCA-7 shows the derivation of the factors used for the assignment of demand production costs between seasons. As a result of the base, intermediate and peak methodology, PNM is assigning approximately 38% of the demand production costs to the summer season and approximately 62% to the non-summer season. For this analysis, PNM used hourly system loads from January 2007 through December 2015.

Q. WHAT ABOUT CUSTOMER CLASSES THAT DO NOT HAVE DEMAND CHARGES?

A. For the rate schedules that do not have demand charges, all of the demand-related costs are collected through the volumetric charges. A comparison of the current and proposed volumetric charges, customer and demand charges, by rate schedule for all retail classes is shown in Rule 530 Schedule O-3.

Q. HOW DOES THE RD MODEL DERIVE PNM'S PROPOSED VOLUMETRIC CHARGES?

A. In terms of calculating the volumetric charges, the RD Model derives: (1) energy rates for the on-peak and off-peak hours by season for PNM's TOU rate schedules; (2) energy rates for each inclining energy block by season for Rate 1A – Residential; and (3) energy rates by season for the various volumetric rate charges that are not subject to a block structure, such as Rate 2A – Small Power and Rate 10A – Irrigation.

Q. WHAT IS PNM'S GUIDING PRINCIPLE FOR THE DESIGN OF VOLUMETRIC CHARGES?

A. To the extent possible, PNM's proposed volumetric charges seek to provide more accurate price signals to customers to better reflect the actual cost of providing energy. In Section V below, I describe the changes proposed to the residential rate design, aimed at facilitating more accurate volumetric price signals and a potential, modified TOU rate in the future. As part of these proposed changes, PNM Witness Chan details the Company's long-term goals for addressing peak demand usage.

Q. HOW DID PNM DETERMINE THE RATE VARIANCES AMONG TOU PERIODS FOR RATE CLASSES UNDER A TOU TARIFF?

A. PNM's variances among seasonal TOU rates reflect the same pricing structure as approved in the 2015 Rate Case.[18] As will be discussed below, PNM has begun working with stakeholders through a mediated process to develop a more effective, modified TOU rate for Commission consideration in the future. As a

[18] CRD at 280 (Decretal Paragraph Q).

result, PNM has not proposed any modifications to PNM's current TOU structures in this case.

Q. IS PNM PROPOSING ANY CHANGES TO FACILITIES CHARGES IN THIS RATE CASE?

A. No. There is only one tariff that has a separately stated rate for facilities, which is Rate 15B – Large Service for Public Universities > 8,000kW Minimum with Customer Owned Generation Facilities Serviced at 115kV ("Rate 15B – Universities"). This facilities charge is a capacity reservation fee for a Company-owned substation serving this rate class, which is priced as a rate component in Rate 15B – Universities.

Q. ARE THE RATES FOR THE LIGHTING CLASSES DESIGNED IN THE SAME MANNER AS FOR OTHER CUSTOMER CLASSES?

A. No. Given the nature of the service for Rate 6 – Private Area Lighting Service ("Rate 6 – Private Lighting") and Rate 20 – Streetlighting, these two classes require a separate process for rate design purposes. However, the class cost allocation and banding for these two lighting classes is performed in the same manner as for the non-lighting classes.[19]

[19] Given that no customer charges are applied to Rate 20 – Streetlights, the allocation of the corresponding interclass subsidy in the banding process is applied to all components, including customer-related costs.

Q. ARE THERE ANY OTHER ADJUSTMENTS OR CREDITS ACCOUNTED FOR IN THE RATE DESIGN MODEL?

A. Yes. In the RD Model, PNM has accounted for the revenue requirement associated with the proposed discounts pursuant to Transitional Rider No. 8 – Incremental Interruptible Power Rate ("Transitional IIPR" or "TIIPR"), which revises the current Rider 8 – Incremental Interruptible Power Rate ("Rider 8 – IIPR").[20] As more fully explained by PNM Witness Chan, PNM is proposing to reduce and potentially eliminate the discounts offered under the current Rider 8 – IIPR. In order to mitigate the significant rate impact on participating customers, PNM is proposing a Transitional IIPR in this case. The eight customers currently on Rider 8 – IIPR will be eligible for the proposed Transitional IIPR discount; these customers are served under the following rate schedules: Rate 3C – General Power Service (Low Load Factor) Time-of-Use ("Rate 3C – General Power Low Load Factor"), Rate 4B - Large Power; and Rate 35B.[21]

Q. HOW DID PNM CALCULATE THE CREDITS APPLICABLE TO CUSTOMERS THAT WILL BE SUBJECT TO THE TRANSITIONAL IIPR?

A. As more fully explained by PNM Witness Chan, PNM proposes to set the proposed discounts at 60% of the current Rider 8 – IIPR discounts, and maintain

[20] Rider 8 – IIPR has been closed since 1999 to new participants.
[21] Only those customers who are served under the current Rider 8 – IIPR tariff are eligible for the Transitional IIPR.

them for a period of four years or until the next rate case, whichever is longer. The revenue requirement associated with these projected discounts for the Test Period was re-allocated to all classes through the banding process, as supported by PNM Witness Chan. Please refer to PNM Exhibit JCA-3, at pages 3-4, and 6-7, lines 12-15.

V. MODIFICATIONS TO THE RESIDENTIAL RATE DESIGN

Q. WHAT IS PNM'S LONG-TERM GOAL FOR ITS RESIDENTIAL RATE STRUCTURE?

A. As explained by PNM Witness Chan, PNM's long-term goal is to work with stakeholders and ultimately design a residential rate structure that will more effectively address growing residential peak demand. This is a multi-step process that will require PNM to adopt a rate design in the future that is more focused on encouraging a shift in the residential usage from peak to non-peak periods. Rate design mechanisms that would address this peak usage could potentially include widespread adoption of TOU rates and/or demand charges. PNM is currently working with stakeholder groups in a mediated process so that PNM can develop a more effective TOU rate for Commission consideration in the future.

Q. IS PNM PROPOSING A MODIFICATION OF ITS TOU RATES IN THIS RATE CASE?

A. No. Given the timing of this rate case in relation to the conclusion of the last rate case, the mediated process has not progressed enough for PNM to put forth a comprehensive proposal in this rate case or to reach agreement with the stakeholders on the best approach going forward. PNM is committed to consulting with stakeholder groups to achieve the goal of developing a well-considered residential TOU rate in the future, as discussed by PNM Witness Chan.

Q. WHAT INTERMEDIATE STEP CAN THE COMPANY UNDERTAKE IN THIS CASE TO PREPARE FOR THE IMPLEMENTATION OF A MORE EFFECTIVE TOU RATE IN THE FUTURE?

A. Because the participation and effectiveness of TOU rates can be heavily influenced by the relative economics of the alternative inclining block rates and/or block rate structure, a modification to the current block rates may be warranted in this case to avoid future rate arbitrage.

Q. PLEASE EXPLAIN THIS RATE ARBITRAGE ISSUE IN MORE DETAIL.

A. Due to the increasing prices in the inclining block rate structure, rate arbitrage is created just by the mere existence of inclining block rates paired with a TOU rate. More specifically, customers should be able to benefit from well-designed TOU rates through one method only: decreasing their on-peak ratio. Reduction of on-peak ratios can be accomplished in two ways: reducing on-peak usage or shifting usage to off-peak times. Contrary to the goal of a well-designed TOU rate, under an inclining block rate structure, the potential benefits of TOU rates are a function of two elements, not just one: (1) the on-peak ratio; and (2) the total energy kWh usage levels. In other words, customers with usage in a higher-priced inclining block may be able to benefit by moving to a TOU rate without reducing on-peak usage or moving usage to off-peak periods. This means that customers with high usage during on-peak times could in fact benefit from TOU rates without any change in behavior. PNM Exhibit JCA-8 shows the relative economics of an inclining block rate structure and its interplay with the TOU rate using PNM's existing rate design approved in the 2015 Rate Case and the proposed rates in this case. PNM Exhibit JCA-8 demonstrates the rate arbitrage I discuss above.

Q. CAN YOU PLEASE DESCRIBE BRIEFLY THE ARBITRAGE ISSUE AS SHOWN IN PNM EXHIBIT JCA-8?

A. Yes. As explained above, under the current inclining block rate structure for Rate 1A – Residential, customers can achieve potential benefits by moving into Rate 1B – Residential TOU for two reasons: (1) benefits that are the result of reduced on-peak energy usage (Area B in PNM Exhibit JCA-8); and (2) benefits that are a result of being a higher usage customer (Area A in PNM Exhibit JCA-8). Moreover, as can be seen in PNM Exhibit JCA-8, the potential benefits for TOU customers actually increase with higher usage when compared to the standard Rate 1A – Residential rates. As such, PNM's current TOU rate coupled with an inclining block structure are unlikely to generate the expected changes in usage behavior during on-peak times or produce any benefits to the system at all, instead generating rate arbitrage benefits to some (likely higher-usage) customers and revenue losses to PNM.

Q. IS PNM PROPOSING TO IMPLEMENT CHANGES TO ITS INCLINING BLOCK RATES IN THIS RATE CASE?

A. Yes. As a first step to reduce the potential rate arbitrage, the Company believes it is appropriate to flatten its residential inclining block rates to foster more effective TOU rates in the future in order to reduce residential peak demand. In particular, PNM's proposed modifications to its inclining block rate prices will reduce the potential benefits that higher use customers could enjoy on the TOU rate as a result of the rate arbitrage with limited or no effect on customer behavior. Please see the difference between Area A and Area C in PNM Exhibit JCA-8.

While PNM is proposing to change the rates for each block, it proposes to maintain the same inclining block structure adopted in Case No. 10-00086-UT (the "2010 Rate Case"), which is: Block 1 = 0 kWh to 450 kWh; Block 2 = 451 kWh to 900 kWh; and Block 3 = 901 kWh or more per month.

Q. IN THEORY, CAN CURRENT INCLINING BLOCK RATES INCENTIVIZE ENERGY CONSERVATION?

A. Possibly. Economic theory suggests that by charging a higher price, customers should be incentivized to reduce or limit their usage. A higher price for electricity also helps customers reduce the payoff of any household investment in energy efficiency measures, assuming customers utilize or could utilize energy at a higher-priced block.

Q. DO THE PARTICULAR FACTS OF PNM'S CUSTOMER USAGE LEVELS INDICATE THAT ITS INCLINING BLOCK RATES ARE ACTUALLY EFFECTIVE AT INCENTIVIZING ENERGY CONSERVATION?

A. Not necessarily. For example, the average user in PNM's service territory uses approximately 563 kWh per month (Test Period) and only 14% of the total residential energy usage occurs in the third block. A very steep price signal for the third block (900kWh+) is likely not effective at discouraging energy usage for the typical average user since he or she may never have any monthly usage in the third block.

Q. WHY IS IT IMPORTANT TO TAKE A FIRST STEP TO ADDRESS THE INCLINING BLOCK RATES TO FACILITATE FUTURE CHANGES IN TOU RATES?

A. As PNM Witness Chan discussed in her Direct Testimony in Case No. 15-00261-UT and again in her Direct Testimony in this case, energy efficiency ("EE") programs, along with distributed generation and Codes & Standards, have reduced residential usage per customer. However, this decline in per-customer energy usage has not translated into a reduction in the residential class' relative contribution to peak demand, since peak demand usage has actually increased for this customer class. As the residential class' peak demand increases, so does its cost responsibility. This increased cost responsibility historically has been shifted to other rate classes through the banding process in order to mitigate rate impacts on residential customers. Ultimately, to effectuate real change in residential cost responsibility and to reduce the subsidization of the residential rate class by other rate classes, residential consumption patterns will need to change.

Q. ARE PNM'S CURRENT INCLINING BLOCK RATE DIFFERENTIALS COST BASED?

A. No. There is no cost support to justify the current rate differentials for PNM's inclining blocks.

Q. DO PNM'S CURRENT INCLINING BLOCK RATES PROVIDE AN ACCURATE PRICE SIGNAL TO ITS CUSTOMERS?

A. No. Under PNM's inclining block rate structure, customers with Block 1 usage pay less than the average cost of electricity service, while users in Block 3 pay significantly above cost. In other words, customers with Block 3 usage end up paying a significant amount more of the allocated residential costs as compared to residential customers that confine their usage to Block 1, resulting in intra-class subsidies. In fact, given that PNM collects such a large portion of its fixed costs in the volumetric rates, customers with Block 3 usage also pay a disproportionate share of all residential customers' fixed costs. Furthermore, given that the rates for Blocks 1 and 2 are currently lower than the average volumetric rate, these block rates could in fact be incentivizing the use of more energy among customers in those blocks.[22] This concern with unintended price signals is exacerbated when considering that recent information from a retail rate reform proceeding in California suggests that many customers have a poor understanding of how inclining block rates work. A rate structure that ultimately includes no block rates but instead utilizes a well-designed TOU rate is more likely to send an accurate price signal to customers about the energy costs incurred by the Company.

Q. WHAT DOES DATA FROM THE CALIFORNIA PROCEEDING SHOW ABOUT RESIDENTIAL CUSTOMERS' UNDERSTANDING OF THEIR RATES?

A. In the California proceeding noted above, the investor-owned utilities (Pacific Gas & Electric Company ("PG&E"), Southern California Edison Company

[22] Given that the average non-fuel rate is approximately 11 cents for Rate 1A – Residential, the Block 1 rate is below average as it is approximately 7.6 cents. The non-summer rate for Block 2 is also below average, as it is approximately 10.5 cents.

("SCE") and San Diego Gas & Electric Company ("SDG&E")) in 2013 jointly commissioned Hiner & Partners to conduct an online survey of approximately 4,200 electric customers in order to develop a better understanding of customer knowledge of, and preferences for, various types of rate plans.[23] The California PUC found that this study demonstrated that at least half of the utilities' customers did not know that their rates were tiered or how a tier structure works, and many other customers did not know what tier they were in, or in which tier they would likely end up during a given billing cycle.[24] The PUC concluded that "[t]hese findings are inconsistent with the assumption that customers study their bill carefully and understand the price of their marginal tier."[25] Moreover, the PUC found that "[r]esidential customers who do not understand that the inclining block price for energy increases as their energy usage increases are more likely to respond to their average bill than the tier price or marginal price."[26] In other words, customers are more likely concerned with the amounts they pay on average, rather than specific components that make up the total amount of a monthly bill.

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[23] California PUC, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates, Rulemaking 12-06-013, at 29 (July 3, 2015) ("California Final Decision"), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.
[24] *Id.* at 59.
[25] *Id.*
[26] *Id.* at 309.

Q. IS THERE ANY EVIDENCE THAT THE CURRENT INCLINING BLOCK STRUCTURE HAS AFFECTED THE RESIDENTIAL PEAK DEMAND?

A. No, inclining blocks do not appear to have a measurable impact on the increasing residential peak demand, given that the current block structure has been in place for a number of years and residential peak has been rising anyway. Further, an inclining block structure does not necessarily provide customers an incentive to conserve electricity at specific times when conservation is most needed, specifically during peak usage periods. For example, given the economics of the inclining block rates, saving energy over the weekend, when the prices of electricity and system peak demands are not as high, is equally valuable to customers as compared to energy savings during the afternoon of a hot summer weekday when the system is experiencing peak demand. In total, customers who might respond to inclining block rates have no reason or motivation to change their on-peak usage rather than their total energy usage. Thus, the current inclining block rate structure does not align costs with potential system benefits resulting from reduced peak usage.

Q. WHAT IS PNM'S CURRENT TIER RATE RATIO FOR RATE 1A – RESIDENTIAL WHEN COMPARING BLOCK 3 RATES TO BLOCK 1 RATES?

A. Under the rates set in the 2015 Rate Case, PNM's tier rate ratio for its summer rates is approximately 1.92 to 1.0, which is calculated by dividing the Block 3 rate of $0.1472299 per kWh by the Block 1 rate of $0.0767429 per kWh. The tier rate ratio for PNM's non-summer rates is approximately 1.56 to 1.0, which is calculated by dividing the Block 3 rate of $0.1198334 per kWh by the Block 1 rate of $0.0767429 per kWh.

Q. HOW DOES PNM'S CURRENT TIER RATE RATIO COMPARE TO OTHER INVESTOR-OWNED UTILITIES IN NEW MEXICO?

A. For its residential customers, El Paso Electric Company ("EPE") has two rate blocks during the summer months (*i.e.*, May through October) and a flat rate during the non-summer months. In the summer, the first rate block (600 kWh or less) is $0.07528 per kWh, while all usage above 600 kWh is $0.09338. Compared to PNM's summer rates, the EPE rate results in a more gradual rate ratio of 1.24 to 1.0.

Southwestern Public Service Company ("SPS") does not have tiered rates for its residential customers in New Mexico. In its Final Order in Case No. 10-00385-UT, the Commission required SPS to complete a study on inclining block rates applicable to residential customers.[27] SPS retained Concentric Energy Advisors to perform the study, which was submitted in SPS's next rate case (Case No. 12-00350-UT). That study concluded that the conservation effect of inclining block

[27] New Mexico PRC, Recommended Decision of the Hearing Examiner, Case No. 12-00350, 2014 N.M. PUC LEXIS 9, *330.

rates was unclear, at best, in SPS's service territory.[28] SPS asserted to the Commission that given this unclear effect, and to promote consistency and customer understandability during difficult economic times, it should not be required to establish inclining block rates.[29] Commission Staff agreed with SPS's proposal, and although the Commission did not specifically address this issue in its final order in Case No. 12-00350-UT, a tiered rate structure was not implemented.

Q. HOW DOES PNM'S INCLINING BLOCK RATES COMPARE TO UTILITIES IN OTHER STATES?

A. In the California retail rate design proceeding, the California PUC determined that a two-tier block rate with a 25% differential will still send consumers an appropriate conservation price signal, meaning that the California utilities were shifting to a ratio of 1.25 to 1.0.[30] Additionally, SCE analyzed the rate structures of the 50 largest utilities in the U.S. by electric sales. SCE found that 22 of these utilities have flat rates, five have declining block rate structures, and 23 others have an inclining block rate structure.[31] A table submitted by SCE in the California proceeding, which is attached as PNM Exhibit JCA-9, shows that most of the utilities with inclining block rates have two tiers or no tiers (depending on

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[28] *Id.* at *330-*331.
[29] *Id.* at *331.
[30] California Final Decision at 268.
[31] Rebuttal Testimony of Southern California Edison Company, R.12-06-013, at 18 (Oct. 17, 2014) (SCE Rebuttal Testimony"), *available at* http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/2395918C4E64C37888257D7400805430/$FILE/R1206013%20Res%20Rate%20Design%20OIR%20-%20SCE-15%20SCE%20Rebuttal%20Testimony.pdf.

the time of the year), and that 14 of those utilities have a tier rate ratio – which is the difference between the rate for the lowest tier and the highest tier – of 1.2 to 1.0, or less.

The data shows that PNM's current summer and non-summer ratios (comparing Block 3 to Block 1) are significantly higher than most other utilities listed in PNM Exhibit JCA-9. In fact, after the California PUC's changes are implemented, the tier ratio for PNM's summer rates would be higher than every other utility listed in PNM Exhibit JCA-9.

Q. GIVEN THAT ENERGY CONSERVATION IS AN IMPORTANT POLICY GOAL FOR THE COMMISSION, WOULD FLATTENING PNM'S TIERED RATES HAVE THE EFFECT OF DISCOURAGING ENERGY CONSERVATION BY RESIDENTIAL CUSTOMERS?

A. At this time, PNM has no evidence to conclude that reducing the rate ratio among the blocks would discourage energy conservation. When EPE proposed its two-tier rate structure in Case No. 09-00171-UT, with a much flatter rate differential, Commission Staff testified that EPE's rates would "encourage conservation and energy efficiency, while mitigating extreme impacts on customers that could result from additional inclining rate blocks with more pronounced rate differentials."[32] The ratio between EPE's two-tier inclining block rates is significantly less than PNM's, with EPE having a ratio of 1.24 to 1.0, while PNM has a ratio of approximately 1.92 to 1.0 for its summer rates. Even if we presume that inclining block rates result in conservation, PNM's block rate differentials do not need to be as punitive as they currently are in order to result in conservation.

The recent California proceeding also is instructive on this point. The California PUC found that a steep differential between rate tiers does not have a correspondingly large impact on energy conservation.[33]

Q. DOES PNM CURRENTLY HAVE EFFECTIVE MECHANISMS FOR ENERGY CONSERVATION?

A. Yes. As can be seen from the Direct Testimony of PNM Witness Chan, energy efficiency programs are having a significant effect on driving down overall customer consumption. When PNM's inclining block structure was first adopted in 1990, the Company did not have energy efficiency programs. Given the success of energy efficiency programs, and the lack of a direct correlation between the tiered block structure and conservation, it does not appear necessary or reasonable to maintain relatively punitive block rate pricing and the resulting

[32] *In the Matter of El Paso Electric Company's General Rate Case Pursuant to Commission Order*, Final Order Conditionally Approving and Clarifying Unopposed Stipulation, 2009 N.M. PUC LEXIS 64, *23 (2009).
[33] California Final Decision at 103. The California PUC, however, did adopt a "Super-User Electric Surcharge" to target users with extreme usage.

intra-class subsidies. As it stands now, the Company is in the initial stages of collaborating with stakeholders on the next generation of rate design options that are targeted at reducing peak demand consumption. However, as discussed above, in order to avoid rate arbitrage and adequately determine if TOU rates will reduce peak consumption, PNM needs to address its inclining block rates, and perhaps eventually, eliminate the block rate structure altogether.

Q. WHAT INCLINING BLOCK RATE RATIOS DOES PNM PROPOSE IN THIS CASE FOR ITS RATE 1A – RESIDENTIAL CUSTOMERS?

A. PNM is proposing a gradual transition to less steep inclining block rate ratios consistent with the industry trends discussed above. Table JCA-3 below shows the current and proposed tier rate ratios by block and season. Even after the proposed changes, Block 2 and Block 3 tier rate ratios are higher than the most of the utilities shown in PNM Exhibit JCA-9, as well as EPE in New Mexico.

Table JCA-3

Tier Rate Ratios			
	Current	**Proposed**	**% Change**
Summer Block 3/Block 1	1.92	1.68	-12.46%
Summer Block 2/Block 1	1.59	1.47	-7.85%
Non-Summer Block 3/Block 1	1.56	1.44	-7.69%
Non-Summer Block 2/Block 1	1.37	1.33	-3.25%

VI. MODIFICATIONS TO VOLTAGE ADJUSTMENT FACTORS

Q. IS PNM REVISING ITS VOLTAGE CLASS ADJUSTMENT FACTORS IN THIS RATE CASE?

A. Yes. PNM is revising the voltage class adjustment factors that reflect the relative energy losses for each class for the Test Period as compared to the Company average energy losses for the Test Period. The Transmission Planning Department at PNM has recalculated the energy losses of the system based on historical data using the period from January through December of 2015. Given that the Test Period losses by voltage level are different from losses used in the 2015 Rate Case, the voltage class adjustment factors must be modified.

Q. HOW ARE THE VOLTAGE CLASS ADJUSTMENT FACTORS CALCULATED?

A. PNM derives the voltage adjustment factors at the different voltage levels, i.e., transmission, subtransmission, substation, primary distribution and secondary distribution, based on the cumulative energy losses discussed above. The cumulative loss factors are reflected in PNM Exhibit JCA-5, pages 1 and 3, column E, which are hard inputs ultimately used in the derivation of the illustrative FPPCAC Factors.34

[34] As noted above, the loss factors are supported by PNM's Transmission Planning Department.

Q. HOW ARE THE VOLTAGE CLASS ADJUSTMENT FACTORS USED FOR RATE DESIGN?

A. As explained above, the revised voltage class adjustment factors are used to calculate PNM's FPPCAC Factors. These revised voltage adjustment factors, as well as the calculated FPPCAC Factors, are presented in PNM Exhibit JCA-5. The FPPCAC Factors are presented for illustrative purposes only in this case.

Q. HOW ARE THE ILLUSTRATIVE FPPCAC FACTORS DERIVED FOR RATE DESIGN?

A. The illustrative FPPCAC Factors are based on the fuel costs as projected in this case. In addition, PNM derived these factors using the method as established by the Commission in Case No. 13-00187-UT, as further modified by the 2015 Rate Case.

Q. WHAT IS THE PURPOSE OF DERIVING THE ILLUSTRATIVE FUEL RATES IN THIS CASE?

A. Although PNM proposes to change the voltage adjustment factors in this case to reflect updated system energy losses, the calculation of projected Test Period Rider 23 FPPCAC Factors using the proposed voltage adjustment factors is provided for illustrative purposes only in calculating the overall bill impact by rate class as presented in PNM Exhibit JCA-10. The current FPPCAC Factors applied to customer bills are not affected by the revisions to the voltage adjustment factors as calculated in this case.

VII. IMPACT OF PNM'S PROPOSED RATE DESIGN ON RATE CLASSES

Q. WHAT EFFECT WILL THIS RATE CASE HAVE ON THE RATES THAT PNM'S CUSTOMERS PAY?

A. Upon full implementation of PNM's proposed rates in this case, the overall impact will be between 7.56% to 12.79%. Note that this 7.56% to 12.79% range includes fuel charges, renewable energy charges and energy efficiency as shown in PNM Exhibit JCA-10. As detailed by PNM Witness Ortiz, PNM has proposed to phase-in its rate increase for this rate case in order to mitigate the overall rate impact on customers if the full revenue requirement is approved by the Commission. Under PNM's phase-in proposal, customers would see a non-fuel rate increases that ranges from 5.16% to 7.94% for each rate class in Phase I. Phase II of the rate increase will result in additional non-fuel rate increases ranging from 5.08% to 7.82% for each rate class.

Q. WHAT DOES THE FOLLOWING SECTION OF YOUR TESTIMONY ADDRESS?

A. Immediately below, I summarize the major rate design changes for PNM's two-part tariffs (i.e., tariffs without demand charges). Later in the section, I summarize rate design changes for PNM's three-part tariffs. Finally, I discuss PNM Exhibit JCA-10, which describes the overall rate impact for each rate schedule.

Two-Part Tariffs

A. Rate 1A/1B – Residential

Q. WHAT CHANGE DOES PNM PROPOSE FOR THE RESIDENTIAL CLASS CUSTOMER CHARGE IN THIS CASE?

A. Consistent with the principle that cost recovery should follow cost causation, and to mitigate intra-class subsidization, PNM is proposing to increase the monthly customer charge for Rate 1A – Residential from the current charge of $7.00 per month to $13.77 per month. If the phase-in approach is accepted by the Commission, the proposed customer charge for the residential class will be $10.39 per month for Phase I and $13.77 per month for Phase II. After both phases of the customer charge increase are implemented, PNM will be recovering through the customer charge approximately 21% of the total demand and customer-related costs incurred to serve this class as determined by the ECCOSS Model. The remainder of the demand and customer-related costs within the banded revenue requirement are included in the volumetric charges for the residential customer class.

Q. IS THE INCREASE IN THE CUSTOMER CHARGE FOR RATE 1A – RESIDENTIAL COST-JUSTIFIED?

A. Yes. As discussed above, the increase in the customer charge will align more closely cost recovery with cost causation, reduce intra-class subsidization and provide residential customers with better price signals as to customer-related costs.

Q. WHAT MODIFICATIONS IS PNM PROPOSING FOR THE EXISTING INCLINING BLOCKS FOR RATE 1A -- RESIDENTIAL?

A. As discussed in Section V above, PNM proposes to maintain the same inclining block structure adopted in the 2010 Rate Case (that is, the kWh range that currently applies for each block). However, the proposed rate design for Rate 1A – Residential will decrease the current tier rate ratios between blocks to more closely align with other utilities and to facilitate the potential transition to more advanced pricing options in the future, such as TOU rates. PNM will keep the existing seasonal parity in the energy rate for the first block, which corresponds to the first 450 kWh per month of usage.

Q. HAS PNM ESTIMATED THE RESIDENTIAL BILL IMPACT OF ITS PROPOSED RATES AT VARIOUS USAGE LEVELS?

A. Yes. PNM Exhibit JCA-18 shows these estimated impacts. An average use residential customer would experience an approximately $10.49 increase on a monthly bill if the total rate increase is approved. The Phase I increase is estimated at $5.82, and the Phase II impact is estimated at an additional $4.67. These bills include the charges associated with the Renewable Energy Rider, Energy Efficiency Rider, and the FPPCAC as projected for the Test Period.

Q. WHAT CHANGES IS PNM PROPOSING TO RATE 1B – RESIDENTIAL TOU?

A. Given the pending mediation between PNM and other interested stakeholders regarding future modification of PNM's TOU rates, PNM is not proposing any structural changes to its current TOU rate at this time. Maintaining the current structure for Rate 1B – Residential TOU will help maintain the relative economics of this optional rate class and will mitigate potential revenue erosion.

B. Rate 2A/2B – Small Power

Q. IS PNM PROPOSING ANY CHANGES TO ITS SMALL POWER RATES?

A. Similar to Rate 1A – Residential, PNM proposes to increase the customer charge from $15.53 per month to $18.33 for Rate 2A – Small Power. This is the cost-based level that results from the ECCOSS Model for this rate class. The proposed fixed monthly charges for the optional Rate 2B – Small Power TOU also will be increased from the current $15.53 per month (including a customer charge of $7.43 and a meter charge of $8.10) to $18.33 per month (including a customer charge of $10.08

and a meter charge of $8.25). PNM proposes to maintain the same tariff structure for Rate 2A – Small Power and Rate 2B – Small Power TOU.

C. Rate 10A/10B – Irrigation

Q. PLEASE DESCRIBE THE CHANGES PNM IS PROPOSING TO IRRIGATION RATES.

A. PNM proposes to maintain the same tariff structure for Rate 10A – Irrigation and Rate 10B – Irrigation TOU. For Rate 10A – Irrigation, PNM proposes to increase the current customer charge from $9.93 per month to $18.33, which collects only 30% of all customer-related costs from this class.[35] PNM proposes not to increase the customer charge to the full cost-based level to mitigate potential rate impacts to customers within this rate class. The customer charge for this rate class would increase by more than 600% if it were taken to the full fixed-cost level. Furthermore, the proposed fixed monthly charges for optional Rate 10B – Irrigation TOU will be increased from the current $9.93 per month (including a customer charge of $7.39 and a meter charge of $2.54) to $18.33 per month (including a customer charge of $12.57[36] and a meter charge of $5.76).

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[35] The proposed customer charge for irrigation customers is the same as the proposal for small power customers due to the fact that absent the end-use requirement, most irrigation customers in Rate 10A – Irrigation would qualify for small power rates.

[36] The $12.57 will allow for the recovery of all customer-related costs, except the meter costs.

D. Rate 11B – Water and Sewage

Q. PLEASE DESCRIBE THE CHANGES PNM IS PROPOSING FOR WATER AND SEWAGE RATES.

A. PNM is proposing to set customer charges that will recover all of the customer-related costs for Rate 11B – Water and Sewage Pumping Service Time-of-Use Rate ("Rate 11B – Water and Sewage"). To reflect this proposal, the monthly customer charge will be reduced from $442.44 to $327.02. Also, as more fully explained above, the volumetric TOU rates applicable to this rate schedule were maintained with a 418% summer on-peak to off-peak rate differential and 234% non-summer on-peak to off-peak rate differential to capture more of the capacity-related costs through the volumetric on-peak rates and to avoid significant rate impacts to customers within this class.[37]

<u>**Three-Part Tariffs**</u>

E. Rate 3B/3C – General Power

Q. WHAT CHANGES DOES PNM PROPOSE FOR GENERAL POWER RATES?

A. PNM is proposing to maintain the same rate design structure and qualification criteria for Rate 3B – General Power and Rate 3C – General Power Low Load Factor (collectively "General Power Rates"). That is, Rate 3B – General Power

[37] Please note that Rate 11B – Water and Sewage has the lowest on-peak ratio usage among all the TOU rate schedules.

will be the most advantageous schedule for qualifying customers with a 35% or better load factor. Furthermore, in order to move closer to cost-based demand rates for Rate 3B – General Power, PNM proposes to set the demand rates at 92% of the cost-based level for the summer months and at 95% for the non-summer months. For Rate 3C – General Power Low Load Factor, the demand rates are proposed to be set at 65% of the cost-based level for both summer and non-summer seasons in order to maintain the relative economics of the General Power Rates, which is a function of each rate class' load factor in this rate case. Rate 3C – General Power Low Load Factor will continue to be the most advantageous schedule for qualifying customers with a 35% or lower load factor.

Q. HAS PNM CONDUCTED A SEPARATE COST OF SERVICE STUDY FOR ITS GENERAL POWER RATES?

A. Yes. As required by the 2015 Rate Case CRD, PNM has conducted a separate cost of service study for Rate 3B – General Power and Rate 3C – General Power Low Load Factor. PNM Witness Vogt discusses the results of each class' separate cost of service study. The rate design proposed in this case incorporates the results of the separate cost of service study conducted for each class separately.

F. Rate 4B – Large Power

Q. WHAT CHANGES ARE PROPOSED FOR RATE 4B – LARGE POWER?

A. In order to more closely align cost recovery with cost causation, PNM proposes to set the demand rates for Rate 4B – Large Power at approximately 85% of the cost-based level for the summer months and at 88% of the cost-based level for the non-summer months. Rate 4B – Large Power will continue to be the most advantageous schedule for qualifying customers with a minimum average peak load of approximately 500 kW per month.

G. Rate 5B – Large Service >=8,000kW

Q. WHAT CHANGES IS PNM PROPOSING FOR RATE 5B – LARGE SERVICE >=8,000KW?

A. PNM proposes to set the demand rates for Rate 5B – Large Service >=8,000kW at 100% of the cost-based level, which is lower than the level for demand-related costs after banding.[38] Also, as indicated per the results of the ECCOSS Model, the customer charge for this class will be reduced from $3,026.64 to $2,498.62 per month.

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[38] The proposed demand rates are set at approximately 87% of the demand-related cost as indicated after banding is applied.

H. Rate 15B – Universities

Q. IS PNM PROPOSING ANY CHANGES FOR RATE 15B – UNIVERSITIES?

A. Yes. PNM proposes to set the demand rates at 99% of the cost-based level for the summer season and 98% for non-summer season. This change is necessary to recognize the recovery of certain demand-related costs through the facilities charges assessed to this class. The combined demand and facilities charges will recover 100% of the demand-related costs.

I. Rate 30B – Manufacturing

Q. PLEASE DESCRIBE ANY CHANGES PNM IS PROPOSING FOR RATE 30B – MANUFACTURING.

A. PNM proposes to set the summer demand rate at approximately 85% of the cost-based level and the non-summer demand rate at approximately 92% of the cost-based level. This change is necessary in order to avoid a disproportionate increase in summer bills as compared to non-summer bills. As indicated per the results of the ECCOSS Model, the customer charge for this class will be reduced from $23,874.89 to $22,462.95 per month.

J. Rate 33B – Station Power

Q. WHAT CHANGES IS PNM PROPOSING FOR RATE 33B – STATION POWER?

A. PNM proposes to set the demand rates for Rate 33B – Large Service for Station Power (Time-of-Use) ("Rate 33B – Station Power") at 100% of the cost-based level, which is lower than the level for demand-related costs after banding.[39]

K. Rate 35B – Large Power >=3,000kW

Q. WHAT CHANGES DOES PNM PROPOSE FOR RATE 35B?

A. PNM proposes to set the demand rates for Rate 35B at 75.1% of the cost-based level for both the summer and non-summer seasons. Demand rates in this case will recover 100% of the demand-related costs after banding.

L. Rate 36B – Special Renewable Rate

Q. WHAT CHANGES DOES PNM PROPOSE FOR RATE 36B?

A. The current rates applicable to the customer served under Rate 36B are expected to be updated based on the final rates approved in PNM's 2015 Rate Case. To update Rate 36B's rates for this case and pursuant to the terms of the contract approved in NMPRC Case No. 16-00191-UT, PNM proposes to adjust the

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[39] The proposed demand rates are set at approximately 74% of the demand-related cost as indicated after banding is applied.

demand rates for this rate class to recover 100% of the demand-related costs shown in the Test Period. Also, PNM is adjusting the customer charge and energy related non-fuel rate applicable to this class. The rates proposed are set to recover 100% of the costs, as dictated by the ECCOSS Model.

M. Revenue Impact of Proposed Rates

Q. HAS PNM ESTIMATED THE OVERALL IMPACT OF ITS PROPOSED RATES FOR ALL CUSTOMER CLASSES?

A. Yes. A side-by-side comparison of the current and proposed base rates by component can be found in Rule 530 Schedule O-3. PNM Exhibit JCA-10 also provides a summary of the estimated impact of proposed rates in this case at the class level, in conjunction with all applicable riders and fuel charges as projected. PNM Exhibit JCA-10 also compares annual revenue under current rates (including the existing Renewable Energy Rider, Energy Efficiency Rider, and the FPPCAC as projected for the Test Period) to annual revenue under proposed rates with the riders and adjustment clauses noted above. Fuel revenues in PNM Exhibit JCA-10 incorporate the assignment of costs for the following three groups of customers based upon the applicability of the fuel costs: Non-Capped/Non-Exempt, Capped and Exempt customers.

Q. WHY DO THE IMPACTS SHOWN IN EXHIBIT JCA-10 INCLUDE THE FPPCAC RIDER 23, RENEWABLE ENERGY RIDER 36 AND ENERGY EFFICIENCY RIDER 16?

A. The energy efficiency and renewable riders and FPPCAC are included in PNM Exhibit JCA-10 for informational purposes only to facilitate the Commission's assessment of an overall impact of PNM's requested non-fuel revenue requirement increase on what customers pay in total. The rates riders and adjustment clauses shown in PNM Exhibit JCA-10 are reviewed and established by the Commission in separate proceedings pursuant to NMPRC rules and regulations.

Q. WHAT PROJECTIONS IS PNM USING FOR FPPCAC RIDER 23, RENEWABLE ENERGY RIDER 36 AND ENERGY EFFICIENCY RIDER 16, AS SHOWN IN PNM EXHIBIT JCA-10?

A. For the FPPCAC, PNM is utilizing the projected fuel costs for the Test Period for both existing and proposed rates. For the Renewable Energy Rider, PNM is using the projected annual costs as filed in PNM Case No. 16-00148-UT, which is the most recent renewable plan filing, for both existing and proposed rates. For the Energy Efficiency Rider, PNM is calculating current and proposed budgets using 3% of projected revenue. For the Profit Incentive component of the Energy Efficiency Rider, PNM is using the stipulated base profit incentive amount of 7.1% of program costs from Case No. 16-00096-UT.

VIII. PROPOSAL FOR THE REMOVAL OF ENERGY EFFICIENCY DISINCENTIVES

Q. HOW DOES YOUR TESTIMONY SUPPORT THE LOST CONTRIBUTION TO FIXED COSTS MECHANISM ("LCFC")?

A. PNM Witness Ortiz supports the policy objectives of PNM's LCFC proposal and my testimony supports the tariff itself, as well as the components of the proposed Rider No. 48 – Lost Contribution to Fixed Costs Mechanism ("Rider 48").

Q. PLEASE EXPLAIN THE COMPONENTS OF THE LCFC TARIFF.

A. To establish Rider 48's LCFC Rider Rate, the Commission must determine in this rate case the amount of fixed costs per kWh embedded in the volumetric rate for each applicable rate class. This cost per kWh is referred to as the Authorized Fixed Cost Recovery Factor. This Authorized Fixed Cost Recovery Factor will be multiplied by the projected energy savings from PNM's energy efficiency and load management programs, called the Projected EE Savings in Rider 48. The resulting amount is referred to as the Lost Fixed Cost Amount, which represents the amount of fixed costs lost due to the implementation of energy efficiency programs.

Q. IF APPROVED, WHEN WILL THE AUTHORIZED FIXED COST RECOVERY FACTOR BE RESET?

A. PNM's approved Authorized Fixed Cost Recovery Factor will remain constant until updated in a subsequent rate case proceeding.

Q. HOW WILL PNM CALCULATE THE AUTHORIZED FIXED COST RECOVERY FACTOR?

A. As set forth in PNM Exhibit JCA-11, the Authorized Fixed Cost Recovery Factor (i.e., fixed costs recovered through volumetric rates) for each rate class is derived by first determining the Total Fixed Cost Requirements. Total Fixed Cost Requirements are calculated as the sum of the customer and demand-related revenue requirements resulting from the ECCOSS Model after banding is applied. Then, the revenue collected from customer charges as proposed in this case for the Test Period is subtracted from the Total Fixed Cost Requirements, with the remainder representing the amount of fixed costs recovered through the energy (volumetric) rates or the Authorized Fixed Cost Recovery Factor.[40] PNM Exhibit JCA-11 sets forth the supporting data to calculate the Authorized Fixed Cost Recovery Factor per kWh applicable to Rate 1A/1B – Residential and Rate 2A/2B – Small Power. As set forth in Rider 48, the applicable Authorized Fixed Cost Recovery Factor for Rate 1A/1B – Residential will be $0.0909201 per kWh and for Rate 2A/2B – Small Power will be $0.1007957 per kWh.

[40] Given that no demand charges apply to Rates 1A/1B – Residential or 2A/2B – Small Power, it is not necessary that PNM take demand charges into account in terms of calculating fixed cost recovery for these two classes.

Q. WHAT TYPES OF COSTS ARE CONSIDERED "FIXED" IN THE CONTEXT OF THE LCFC?

A. In the context of the LCFC, fixed costs are the approved revenue requirements associated with customer-related and demand-related activities, which do not vary as a result of energy sales (kWh). Fixed costs consist of all after-banding production, transmission, distribution demand-related costs and customer-related costs allocated to each rate case. The identification of these costs and the associated revenue requirements are calculated within the Company's filed ECCOSS Model after banding, and reproduced in PNM Exhibit JCA-11. As noted above, the customer-related costs are accounted by deducting the associated revenues from the Authorized Fixed Cost Recovery Factor.

Q. HOW WILL PNM CALCULATE THE LOST FIXED COST AMOUNT?

A. As explained earlier, the Lost Fixed Cost Amount is the result of multiplying the Authorized Fixed Cost Recovery Factor by the projected energy savings from PNM's energy efficiency and load management programs.

Q. ONCE THE LOST FIXED COST AMOUNT IS CALCULATED, HOW WILL PNM RECOVER THESE COSTS?

A. PNM will collect the Lost Fixed Cost Amount through a per kWh rider rate applied to all energy usage experienced by Rate 1A/1B – Residential and Rate 2A/2B – Small Power customers. This kWh charge is called the LCFC Rider

Rate. More specifically, the Lost Fixed Cost Amount will be divided by the projected customer class billing determinants for the applicable calendar year to derive the LCFC Rider Rate. For purposes of recovery of the Lost Fixed Cost Amount, PNM will have separate LCFC Rider Rates for Rate 1A/1B – Residential and Rate 2A/2B – Small Power. The Lost Fixed Cost Amount will be recovered concurrently with the implementation of energy efficiency and load management programs and will be reset annually based upon the projected energy efficiency savings for the following calendar year.[41] Once the measured and verified energy efficiency savings are known, the amount collected through the LCFC Rider Rate will be trued up in each subsequent year as part of a reconciliation filing.[42] PNM Witness Ortiz also discusses the reconciliation filing.

Q. ONCE IMPLEMENTED, HOW WILL PNM TRACK THE RECOVERY OF THE LOST FIXED COST AMOUNT?

A. PNM will make an Advice Notice filing each year for reconciliation or true-up the LCFC Rider Rate, called the Reconciliation Reset. In this filing, PNM will identify the measured and verified energy efficiency and load management savings from the prior year. PNM will multiply these kWh savings by the Authorized Fixed Cost Recovery Factor to determine the total lost fixed costs that the Company should have collected under the LCFC.[43] PNM will then calculate

[41] Rider 48 refers to this annual filing as the "Annual Reset."
[42] This reconciliation filing is referred to as the "Reconciliation Reset" in Rider 48.
[43] In Rider 48, this amount is referred to as the "Lost Fixed Cost Verified Amount."

any over or under recovery of its actual lost fixed costs compared to revenues collected under the LCFC Rider.[44] Each year, after PNM's Advice Notice is permitted to become effective, PNM will adjust the subsequent LCFC Rider Rate to collect or credit any over or under recovery. This reconciliation amount will be collected through December of the year in which the Advice Notice is filed. In summary, the true-up process will account for any differences between what was collected from customers based upon projected energy efficiency savings in PNM's annual energy efficiency plan in the prior year and what should have been collected from customers as a result the measured and verified energy efficiency savings.[45]

Q. WILL PNM BE ABLE TO COLLECT ALL OF ITS LOST FIXED COSTS ASSOCIATED WITH ENERGY EFFICIENCY THROUGH THE LCFC?

A. No. For example, PNM will not collect any lost fixed costs experienced by rate classes other than the residential and small power rate classes.[46] Also, PNM is capping the amount of energy efficiency savings recovered through the LCFC Rider at four years when the savings for these programs tend to last longer. PNM Witness Ortiz also discusses this issue.

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[44] The actual amount collected from customers under the LCFC Rider Rate is called the "Actual Fixed Cost Amount Collected" in Rider 48.

[45] The measured and verified energy efficiency savings is called M&V EE Savings in Rider 48.

[46] Furthermore, PNM will not collect any fixed costs associated with non-energy savings, such as demand savings, experienced by some non-residential customers participating in energy efficiency activities.

Q. WHY IS PNM PROPOSING TO SEPARATELY ASSESS THE LCFC RIDER RATE TO RESIDENTIAL AND SMALL POWER CUSTOMERS?

A. PNM's proposal is aimed at reducing cross subsidies between these two rate classes. I performed an analysis using the assumption that Rider 48 as proposed had been in place since the 2010 Rate Case and continued through 2017.[47] The assumptions included removing annual, incremental energy efficiency measure savings from the total energy efficiency savings used to calculate the LCFC Rider Rate after four years had passed and a rate case was not completed. In every year of the analysis, residential customers were being subsidized by small business customers if the LCFC Rider Rate was combined and not separately assessed to each rate class. Given that the residential rate class is already heavily subsidized, PNM believes it is appropriate to separately assess the LCFC Rider Rate to residential and small business customers. This analysis is shown in PNM Exhibit JCA-17.

[47] For simplicity and illustrative purposes, this analysis does not, however, "reset" the cumulative energy efficiency savings in 2016, which would have occurred as a result of the implementation of new rates in Case No. 15-00261-UT had the mechanism been in place since 2010.

IX. ENHANCEMENTS TO RATE 20 – STREETLIGHTING TARIFF IN ORDER TO ADDRESS CERTAIN REQUIREMENTS FROM THE 2015 RATE CASE.

Q. IS PNM PROVIDING A SEPARATE RATE DESIGN MODEL FOR STREETLIGHTING TARIFF RATE 20?

A. Yes. PNM Exhibit JCA-12 is the rate design model for Rate 20 – Streetlighting, and it includes a summary of the process PNM undertook to determine the proposed rates under this rate schedule, as well as the development of the Consolidation Adjustment Rider No. 35 ("CAR") rates applicable to this class.

Q. WHAT MODIFICATIONS WERE MADE TO PNM'S STREETLIGHTING TARIFF THE 2015 RATE CASE?

A. In the 2015 Rate Case, the Company received approval for a single, consolidated set of base Streetlighting rates, including pole, light and ownership options for both PNM North and South customers. However, to mitigate any extreme rate impacts to PNM South customers, the Commission approved PNM's proposal to maintain the CAR for the Rate 20 – Streetlighting class. The Commission also approved the Company's proposals to comprehensively re-design the Streetlighting tariff, as well as to add new features to this tariff that permitted additional opportunities to tailor streetlighting options and readily use energy efficient lighting.

As the Company pointed out in the 2015 Rate Case, Rate 20 – Streetlighting was both overly complex and fairly limited in terms of the flexibility it afforded customers. The approved re-design of this tariff resolved some of these issues by simplifying the tariff, while also providing more flexibility in the types of streetlights that can be chosen and the services offered by PNM via this tariff.

Q. PLEASE DISCUSS THE STAKEHOLDER PROCESS FOR THE STREETLIGHTING TARIFF THAT WAS A REQUIREMENT FROM THE 2015 RATE CASE.

A. The 2015 Rate Case CRD required that PNM meet with interested stakeholders regarding proposals made during the course of the 2015 Rate Case that were deemed to be premature by the Hearing Examiner.

Q. WHAT ISSUES IS PNM REQUIRED TO ADDRESS IN THIS CASE REGARDING THE STREETLIGHTING TARIFF AS A RESULT OF THE 2015 RATE CASE?

A. In its Final Order in the 2015 Rate Case, the Commission ordered PNM to convene stakeholder meetings (inviting intervenors to this case and other interested stakeholders, such as municipalities) to discuss the following issues for inclusion in PNM's next base rate case: conversion of high pressure sodium lighting to LED lighting, including a) 100,000 hour lights; b) metering and advanced lighting control options at the request of the customer; c) salvage values and recovery of undepreciated assets; d) expanded lighting range options for conversion; and e) installation allowances. PNM also was ordered to develop the cost and technical data necessary to develop a tariff that includes these items.[48] PNM held a meeting with stakeholders on October 24, 2016. A summary of the discussions at that meeting is attached as PNM Exhibit JCA-13. As a follow-up, PNM met with the City of Albuquerque on November 10, 2016.

Q. AS A RESULT OF THESE MEETINGS, ARE THERE FURTHER ENHANCEMENTS PNM IS PROPOSING FOR THE STREETLIGHTING TARIFF IN THIS RATE CASE REGARDING THE LIFE OF THE COMPANY-OWNED LED LIGHTS?

A. Not in this rate case. As a result of the October 24, 2016 meeting, PNM anticipates filing an independent Advice Notice to request that the Commission modify its existing language in Rate 20 – Streetlighting to offer Company-owned LED streetlights with an estimated life-span of 100,000 hours. This new language will also provide flexibility to PNM to offer more advanced lighting fixtures as LED technology evolves. Because the separate Advice Notice filing is not intended to affect any items of cost or rates and given the length of time it takes to complete rate cases, PNM believes it is more efficient and beneficial to its customers to seek descriptive changes to Rate 20 – Streetlighting in a stand-alone Advice Notice filing. However, the language PNM will be proposing in this

[48] CRD at 280.

anticipated Advice Notice filing is incorporated into the proposed tariff for Rate 20 – Streetlighting in this rate case filing for consistency purposes.

Q. IS PNM PROPOSING ANY CHANGES TO THE STREETLIGHTING TARIFF IN THIS RATE CASE REGARDING METERING AND ADVANCED LIGHTING CONTROL OPTIONS?

A. Not for this rate case. PNM and stakeholders are and will continue working collaboratively to find potential solutions for the issues around the implementation of advanced metering for Streetlighting. To date, PNM has developed a cross-functional PNM team to work with interested stakeholders, particularly with the City of Albuquerque, to gain a better understanding of stakeholder decisions or ongoing proposals related to advance metering and lighting control options. As part of this joint process, PNM and the stakeholders are evaluating the operational, legal and regulatory implications of implementing advanced metering control options for customer-owned and Company-owned LED lighting alternatives. However, many of the issues that were not resolved during the 2015 Rate Case remain in discussion with stakeholders. For example, to the extent that PNM could potentially receive usage data from a municipality that installed its own metering for streetlights, as currently being contemplated by the City of Albuquerque, PNM is working to establish the various ways in which data might be transmitted or otherwise provided to PNM. Related issues about verification of the accuracy of the usage data, as well as other metering equipment ownership and control, also remain under preliminary discussion among PNM and interested stakeholders. A general rate case is not a conducive forum for these metering and advanced lighting control issues. PNM is therefore continuing to work with its Streetlighting stakeholders on an independent track that will allow potential solutions to be presented in a future filing.

Q. IS PNM PROPOSING ANY CHANGES TO THE STREETLIGHTING TARIFF IN THIS RATE CASE REGARDING SALVAGE VALUES AND RECOVERY OF UNDEPRECIATED ASSETS?

A. Not for this rate case. PNM believes that the current tariff allows a customer to come forward with a broad-based initiative to conduct a large-scale replacement of Company-owned lighting, with the Company determining the salvage value, if any, that could be gained from this large-scale early retirement of operational standard lighting on a project-specific basis.

Q. IS PNM MODIFYING ITS STREETLIGHTING TARIFF IN THIS RATE CASE TO ACCOUNT FOR EXPANDED LIGHTING RANGE OPTIONS FOR CONVERSIONS?

A. No, such a proposal is moot. As discussed with stakeholders, PNM's suite of operational LED substitutes for PNM-owned standard lighting can replace approximately 98% of existing standard lights, so there is no need to expand PNM's planned offering of LED options for conversions. No stakeholder suggested that additional operational substitutes should be included in PNM's current offerings during the October 24, 2016 stakeholder meeting.

Q. IS PNM MODIFYING ITS INSTALLATION ALLOWANCES IN THIS RATE CASE?

A. Yes. As part of the overall rate design process in this case, PNM has re-calculated the installation allowances, which represent the Company's portion of the costs for installation of a particular light/fixture/pole. As explained during the October 24, 2016 stakeholder meeting, the installation allowances facilitate the adoption of more advanced lighting options, while providing price signals to reflect the cost of such installations for Rate 20 – Streetlighting customers. These installation allowances also mitigate the rate impact of conversions on certain customers, balancing the needs of smaller and larger Streetlighting customers. For instance, higher allowances will result in lower upfront costs but higher monthly rates. Lower allowances will result in higher upfront costs but lower monthly rates. While PNM's larger Streetlighting customers may be able to afford a lower allowance, thus covering more of their upfront costs, PNM's smaller customers may require lower upfront costs (or higher allowances). PNM's revised installation allowances are shown in PNM Exhibit JCA-12, at page 1. These installation allowances remain approximately at the same levels as approved in the 2015 Rate Case.

Q. IS THE COMPANY PROPOSING TO MAINTAIN THE CAR FOR THE STREETLIGHTING CLASS?

A. Yes. For PNM South Streetlighting customers, which consist almost exclusively of municipalities, full integration into the combined Streetlighting tariff approved in the 2015 Rate Case could result in very large price increases for some lights and poles. This is due, in part, to the fact that the Streetlighting rates for PNM South customers have never truly been cost-based. To mitigate the bill impact while facilitating a gradual movement to cost-based rates, PNM will continue with the application of a fixed light and pole combination CAR rates for PNM South Streetlighting customers, but these CAR rates will represent a lower subsidy amount than what was approved in the 2015 Rate Case. The resulting effect will be an overall reduction in the total revenue requirement associated with the CAR, effectively moving closer to equal rates for both PNM North and South territories. This practice is consistent with the principle of gradualism that I discuss early in my testimony.

Q. CAN YOU EXPLAIN IN MORE DETAIL THE PROPOSED CAR FOR STREETLIGHTING CUSTOMERS?

A. Yes. As noted above, the continuation of the proposed CAR is meant to mitigate the impact of consolidated Streetlighting tariff on PNM South customers. The CAR will limit the impact of the proposed Streetlighting rates for these PNM South customers. PNM Exhibit JCA-12 at pages 7-8 describes in more detail the development of the CAR for Rate 20 – Streetlighting under proposed rates.[49] Without the application of the CAR, certain PNM South customers would experience a non-fuel increase as high as 126%, which is contrary to the principle of gradualism. PNM Exhibit JCA-12 at page 9 also compares rates impact for PNM South Streetlighting customers with and without the proposed CAR.[50]

Q. HAS PNM CHANGED THE RATE DESIGN FOR RATE 6 – PRIVATE LIGHTING IN THIS CASE?

A. No. The rate design presented in this case for Rate 6 – Private Lighting is the same as the one used in the 2015 Rate Case. PNM Exhibit JCA-14 describes the rate design for Rate 6 – Private Lighting. Per the terms of the tariff, Rate 6 – Private Lighting is closed to new customers and is only applicable to existing lights installed before August 2011. Please note that the CAR is not applicable to Rate 6 – Private Lighting.

X. OTHER MISCELLANEOUS TARIFF CHANGES

Q. IS THE COMPANY MAKING ANY MODIFICATIONS TO ITS TARIFFS?

A. Yes. PNM has revised its current tariffs to reflect the corresponding rates sought to be approved in this case. Additionally, for the proposed phase-in of rates,

[49] No CAR was applied to Private Lighting Rate 6.
[50] PNM is not proposing a CAR rate applicable to the following lights: L6F2 - Sch IV (OH-MP): 2-400W MV and L6F4 - Sch V (UG-MP): 2-400W MV, which do not exist in the field and will never be installed.

PNM is providing alternative tariffs attached to the Advice Notice showing the rates applicable to each rate class in each phase if PNM's full revenue requirement is approved. The second phase reflects the full rates for which PNM seeks approval. The proposed changes to Rate 20 – Streetlighting tariff in legislative format are attached as PNM Exhibit JCA-15. An explanation of the tariff changes is also provided in Rule 530 Schedule O-4.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

GCG#522677

Statement of Qualifications

PNM Exhibit JCA-1

Is contained in the following 4 pages

JULIO C. AGUIRRE

EXPERIENCE AND QUALIFICATIONS

CURRENT POSITION: *Lead Pricing Analyst*, Pricing and Regulatory Services. Public Service Company of New Mexico (PNM)

EDUCATION:

B.S. International Economics, Autonomous University of Chihuahua (UACH), 2005.

M.A. Economics, *Specialization in Public Utility Policy & Regulation*. New Mexico State University (NMSU), 2007.

EXPERIENCE:

Lead Pricing Analyst, Public Service Company of New Mexico (PNM). (11/2015-Present)

Senior Pricing Analyst, Public Service Company of New Mexico (PNM). (11/2010-10/2015)

Economist, Regulatory Operations Staff, Public Utilities Commission of Nevada. (12/2009-11/2010).

Senior Utility Analyst, Regulatory Operations Staff, Public Utilities Commission of Nevada. (09/2007-11/2009)

Research Assistant, Center for Personal Finance and Economic Education (CEPFE), New Mexico State University (NMSU). (01/2006-06/2007)

Research Associate, Research Institute for Economic and Technological Development (IIDEyT), Chihuahua Mexico. (01/2002-07/2005)

PREVIOUS TESTIMONY

Proceeding	Regulatory Body	Docket No.
Application of Sierra Pacific Power Company for authority to begin to recover the costs of constructing the new Tracy Combined Cycle Unit and other plant additions and costs of service through an increase of its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related	Public Utilities Commission of Nevada	07-12001
Application of Nevada Power Company for approval of its 2008 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2007-2026 Integrated Resource Plan.	Public Utilities Commission of Nevada	08-08011
Application of Sierra Pacific Power Company filed under Advice Letter No. 490-E to revise the Statement of Rates and Interruptible Irrigation Service Schedule No. IS-2 to increase the IS-2 rate and establish the Peak Period Non-Curtailment Penalty rate.	Public Utilities Commission of Nevada	08-10043
Application of Nevada Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, environmental retrofits, and other generating, transmission, and distribution plant additions; to reflect changes in cost of service; and for relief properly related thereto.	Public Utilities Commission of Nevada	08-12002
Application of Southwest Gas Corporation for authority to increase its rates and charges for natural gas service for all classes of customers in Southern and Northern Nevada.	Public Utilities Commission of Nevada	09-04003
Application of Sierra Pacific Power Company d/b/a NV Energy filed under Advice Letter No. 503-E to revise Interruptible Irrigation Service Schedule No. IS-2 to increase the IS-2 rate and decrease the Peak Penalty rate.	Public Utilities Commission of Nevada	09-09020
Application of Nevada Power Company d/b/a NV Energy for approval of its 2010-2029 Triennial Integrated Resource Plan.	Public Utilities Commission of Nevada	10-02009

Annual Report of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy on compliance with the Portfolio Standard for Renewable Energy for Compliance Year 2009.	Public Utilities Commission of Nevada	10-04002
Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	Public Utilities Commission of Nevada	10-06001
Application of Sierra Pacific Power Company d/b/a NV Energy for authority to increase its annual revenue requirement for general rates charged to all classes of gas customers and for relief properly related thereto.	Public Utilities Commission of Nevada	10-06002
Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2011-2030 Triennial Integrated Resource Plan.	Public Utilities Commission of Nevada	10-07003
In the Matter of the Application of Public Service Company of New Mexico for Approval of the City of Santa Fe 2012 Underground Project Rider pursuant to Advice Notice No. 447.	New Mexico Public Regulation Commission	12-00100-UT
In the Matter of the Public Service Company of New Mexico's Advice Notice No. 471 and Request for Variance (Energy Efficiency Reconciliation).	New Mexico Public Regulation Commission	13-00113-UT
In the Matter of the Application of Public Service Company of New Mexico for Approval of Renewable Energy Rider No. 36 Pursuant to Advice Notice No. 439 and for Variances from Certain Filing Requirements.	New Mexico Public Regulation Commission	12-00007-UT
In the Matter of the Application of Public Service Company of New Mexico 's Advice Notice No. 490 and Request for Variance related to the Reconciliation of Energy Efficiency Costs, Revenues and Profit Incentives.	New Mexico Public Regulation Commission	14-00111-UT
In the Matter of the Application of Public Service Company of New Mexico for Revision to its Retail Electric Rates Pursuant to Advice Notice No. 507.	New Mexico Public Regulation Commission	14-00332-UT

In the Matter of the Application of Public Service Company of New Mexico for Revision to its Retail Electric Rates Pursuant to Advice Notice No. 513.	New Mexico Public Regulation Commission	15-00261-UT
In the Matter of the Application of Public Service Company of New Mexico for Approval of its 2017 Electric Energy Efficiency Program Plan, Profit Incentive and Revised Rider No. 16.	New Mexico Public Regulation Commission	16-00096-UT

Alphabetical Listing of Acronyms Used in This Testimony

PNM Exhibit JCA-2

Is contained in the following 2 pages

PNM Exhibit JCA-2
ACRONYMS USED IN TESTIMONY

Term	Acronym
3-Summer/1-Winter Coincident Peak	3S1WCP
California PUC, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates, Rulemaking 12-06-013, at 29 (July 3, 2015)	California Final Decision
Consolidation Adjustment Rider	CAR
Corrected Recommended Decision	CRD
El Paso Electric Company	EPE
Embedded Class Cost of Service Study	ECCOSS Model
Energy efficiency	EE
Federal Energy Regulatory Commission	FERC
Fuel and Purchased Power Cost Adjustment Clause	FPPCAC
Lost Contribution to Fixed Costs	LCFC
New Mexico Public Regulation Commission	NMPRC or Commission
NMPRC Case No. 10-00086-UT	2010 Rate Case
NMPRC Case No. 15-00261-UT	2015 Rate Case
Phase I of Proposed Rate Phase-in Effective January 1, 2018	Phase I
Phase II of Proposed Rate Phase-in Effective January 1, 2019	Phase II
Pacific Gas & Electric Company	PG&E
Public Service Company of New Mexico	PNM or Company
Rate Design Model	RD Model
Rate 1A – Residential Service	Rate 1A – Residential
Rate 1B – Residential Service Time-of-Use	Rate 1B – Residential TOU, together with Rate 1A – Residential, Rate 1A/1B – Residential
Rate 2A – Small Power Service	Rate 2A – Small Power
Rate 2B – Small Power Service Time-of-Use	Rate 2B – Small Power TOU, together with Rate 2A – Small Power, Rate 2A/2B – Small Power
Rate 3B – General Power Service Time-Of-Use	Rate 3B – General Power
Rate 3C – General Power Service (Low Load Factor) Time-of-Use	Rate 3C – General Power Low Load Factor, together with Rate 3B – General Power, General Power Rates
Rate 4B – Large Power Service Time-of-Use	Rate 4B – Large Power
Rate 5B – Large Service>= 8,000 kW	Rate 5B – Large Service >=8,000

Term	Acronym
Rate 6 – Private Area Lighting Service	Rate 6 – Private Lighting
Rate 10A – Irrigation Service	Rate 10A – Irrigation
Rate 10B – Irrigation Service Time-of-Use	Rate 10B – Irrigation TOU, together with Rate 10A – Irrigation, Rate 10A/10B – Irrigation
Rate 11B – Water and Sewage Pumping Time-Of-Use Rate	Rate 11B – Water and Sewage
Rate 15B – Large Service for Public Universities > 8,000 kW Minimum	Rate 15B –Universities
Rate 20 – Integrated System Streetlighting and Floodlighting Service	Rate 20 – Streetlighting or Streetlighting
Rate 30B – Large Service for Manufacturing >= 30,000 kW	Rate 30B –Manufacturing
Rate 33B – Large Service for Station Power (Time-of-Use)	Rate 33B – Station Power
Rate 35B – Large Power Service >=3,000kW	Rate 35B
Rate 36B – Special Service Rate – Renewable Energy Resources	Rate 36B – Special Renewable Rate or Rate 36B
Renewable Energy Rider 36	Renewable Energy Rider or Rider 36
Rider No. 48 – Lost Contribution to Fixed Costs Mechanism	Rider 48
Rider 8 – Transitional Incremental Interruptible Power Rate	Rider 8 – IIPR
Reactive kilovolt amperes	RkVA
San Diego Gas & Electric Company	SDG&E
Southern California Edison Company	SCE
Southwestern Public Service Company	SPS
Time-of-Use	TOU
Transitional Rider No. 8 –Incremental Interruptible Power Rate	Transitional IIPR or TIIPR

Final Revenue Allocation to Each Customer Class Before and After Banding

PNM Exhibit JCA-3

Is contained in the following 7 pages

PUBLIC SERVICE COMPANY OF NEW MEXICO
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY- REVENUE REQUIREMENTS AT FULL COST OF SERVICE
NMPRC CASE NO. 16-00076-UT
Source: PNM Exhibit SAV-4, pp. 228-229)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
				Residential	Small Power	General Power	General Power	Large Power	Large Service for Customers >=8,000kW	Irrigation	Wter/Swg Pumping	Universities	Manufacturing	Large Power	Large Power	Special Service	Private Lighting	Streetlighting
			Total	Schedule 1	Schedule 2	Schedule 3B	Schedule 3C	Schedule 4	Schedule 5	Schedule 10	Schedule 11	Schedule 15	Schedule 30	Schedule 33B	Schedule 35B	Schedule 36B	Schedule 6	Schedule 20
			PNM	Residential	Small Power	General Power	General Power Low Load Factor	Large Power	Large Service >=8,000kW	Irrigation	Water & Sewage	(Universities 115 kV)	(Manuf, 12.5 kV)	Station Power	Large Power >=3,000kW	Special Service - Renewable Energy Resources	Private Area Lighting	Streetlighting
	SUMMARY - @ Requested ROR																	
1	Equalized Rate of Return		7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%
2																		
3																		
4																		
5	**Demand Components**	$ 635,976,672	$ 635,976,672	$ 311,095,456	$ 87,271,666	$ 111,058,507	$ 14,784,726	$ 66,992,090	$ 3,304,829	$ 2,120,674	$ 9,293,242	$ 3,164,615	$ 14,527,664	$ 118,438	$ 8,417,160	$ 1,185,639	$ 641,582	$ 2,000,384
6	Demand Production		$ 407,031,518	$ 196,206,114	$ 54,321,055	$ 70,899,580	$ 8,677,637	$ 46,318,527	$ 2,577,343	$ 1,123,323	$ 4,765,987	$ 2,612,549	$ 11,530,760	$ 98,575	$ 6,690,715	$ -	$ 285,259	$ 924,095
7	Demand Transmission		$ 88,928,796	$ 43,014,167	$ 11,850,743	$ 15,009,456	$ 1,826,571	$ 9,797,004	$ 538,588	$ 239,904	$ 950,020	$ 552,067	$ 2,354,840	$ 19,863	$ 1,371,079	$ 1,185,639	$ 51,623	$ 167,232
8	Demand Substation		$ 22,413,542	$ 10,395,070	$ 3,051,605	$ 3,637,285	$ 619,077	$ 2,439,005	$ 188,898	$ 109,547	$ 802,174	$ -	$ 642,063	$ -	$ 355,366	$ -	$ 44,068	$ 129,385
9	Demand Distribution Primary		$ 73,441,392	$ 35,960,959	$ 10,556,796	$ 12,582,914	$ 2,141,651	$ 8,437,554	$ -	$ 378,969	$ 2,775,061	$ -	$ -	$ -	$ -	$ -	$ 152,449	$ 455,039
10	Demand Distribution Secondary		$ 44,161,424	$ 25,519,146	$ 7,491,469	$ 8,929,273	$ 1,519,790	$ -	$ -	$ 268,930	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,183	$ 324,633
11																		
12	**Energy Components**	$ 54,151,345	$ 54,151,345	$ 20,950,398	$ 6,062,720	$ 10,898,622	$ 1,392,144	$ 7,545,394	$ 518,636	$ 155,084	$ 1,229,620	$ 481,552	$ 2,671,669	$ 22,205	$ 1,512,315	$ 278,918	$ 101,916	$ 330,151
13	Energy Fuel		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Energy Non-Fuel		$ 54,151,345	$ 20,950,398	$ 6,062,720	$ 10,898,622	$ 1,392,144	$ 7,545,394	$ 518,636	$ 155,084	$ 1,229,620	$ 481,552	$ 2,671,669	$ 22,205	$ 1,512,315	$ 278,918	$ 101,916	$ 330,151
15																		
16	**Customer Components**	$ 101,509,361	$ 101,509,362	$ 77,334,776	$ 11,621,477	$ 3,402,555	$ 773,383	$ 1,614,346	$ 59,967	$ 242,925	$ 643,583	$ 53,175	$ 269,556	$ 5,463	$ 159,889	$ 30,638	$ 913,716	$ 4,383,912
17	Customer Services		$ 10,697,675	$ 10,250,319	$ 447,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Customer Meter		$ 24,619,918	$ 15,495,273	$ 5,231,776	$ 1,946,985	$ 526,777	$ 694,345	$ 6,116	$ 192,534	$ 501,642	$ 3,059	$ 3,059	$ 3,059	$ 12,235	$ 3,059	$ -	$ -
19	Customer Meter Reading		$ 12,692,226	$ 11,295,413	$ 1,275,047	$ 81,667	$ 22,353	$ 5,479	$ 48	$ 8,066	$ 3,959	$ 24	$ 24	$ 24	$ 97	$ 24	$ -	$ -
20	Customer Billing & Collection		$ 23,548,437	$ 20,982,089	$ 2,098,473	$ 282,942	$ 55,009	$ 110,550	$ 76	$ 12,741	$ 6,253	$ 38	$ 38	$ 38	$ 152	$ 38	$ -	$ -
21	Customer Service and Information		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Customer Other		$ 29,951,104	$ 19,311,684	$ 2,568,825	$ 1,090,962	$ 169,244	$ 803,972	$ 53,725	$ 29,584	$ 131,730	$ 50,054	$ 266,434	$ 2,342	$ 147,404	$ 27,517	$ 913,716	$ 4,383,912
23																		
24																		
25	TOTAL COMPANY	$ 791,637,379	$ 791,637,380	$ 409,380,632	$ 104,955,863	$ 125,359,685	$ 16,950,253	$ 76,151,831	$ 3,883,432	$ 2,518,683	$ 11,166,445	$ 3,699,342	$ 17,468,888	$ 146,106	$ 10,089,364	$ 1,495,195	$ 1,657,214	$ 6,714,447
26																		
27	**Total Non-Fuel Revenue Requirements**		**$ 791,637,379**	**$ 409,380,632**	**$ 104,955,863**	**$ 125,359,685**	**$ 16,950,253**	**$ 76,151,831**	**$ 3,883,432**	**$ 2,518,683**	**$ 11,166,445**	**$ 3,699,342**	**$ 17,468,888**	**$ 146,106**	**$ 10,089,364**	**$ 1,495,195**	**$ 1,657,214**	**$ 6,714,446**
28																		
29																		
30	*Target Revenue Requirements at Full Cost of Service*		*$ 791,637,379*	*$ 409,380,632*	*$ 104,955,863*	*$ 125,359,685*	*$ 16,950,253*	*$ 76,151,831*	*$ 3,883,432*	*$ 2,518,683*	*$ 11,166,445*	*$ 3,699,342*	*$ 17,468,888*	*$ 146,106*	*$ 10,089,364*	*$ 1,495,195*	*$ 1,657,214*	*$ 6,714,446*

This schedule sponsored by PNM Witness Aguirre

PUBLIC SERVICE COMPANY OF NEW MEXICO
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY- REVENUE REQUIREMENTS AT FULL COST OF SERVICE
NMPRC CASE NO. 16-00276-UT

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
				Residential	Small Power	General Power	General Power	Large Power	Large Service for Customers >=8,000kW	Irrigation	Wter/Swg Pumping	Universities	Manufacturing	Large Power	Large Power	Special Service	Private Lighting	Streetlighting
			Total	Schedule 1	Schedule 2	Schedule 3B	Schedule 3C	Schedule 4	Schedule 5	Schedule 10	Schedule 11	Schedule 15	Schedule 30	Schedule 33B	Schedule 35B	Schedule 36B	Schedule 6	Schedule 20
			PNM	Residential	Small Power	General Power	General Power Low Load Factor	Large Power	Large Service >=8,000kW	Irrigation	Water & Sewage	(Universities 115 kV)	(Manuf, 12.5 kV)	Station Power	Large Power >=3,000kW	Special Service - Renewable Energy Resources	Private Area Lighting	Streetlighting
	SUMMARY - @ Requested ROR																	
1	36B Production Credit Allocator (% 3S1W)		100.00%	49.01%	13.52%	17.10%	2.08%	11.17%	0.61%	0.27%	1.08%	0.63%	2.68%	0.02%	1.56%	0.00%	0.06%	0.19%
2	36B Production Credit ($)	$ (877,302)	$ (877,302)	$ (430,008)	$ (118,630)	$ (150,031)	$ (18,264)	$ (97,965)	$ (5,373)	$ (2,405)	$ (9,509)	$ (5,528)	$ (23,527)	$ (199)	$ (13,704)	$ -	$ (509)	$ (1,650)
3																		
4																		
5	**Demand Components**	$ 635,976,672	$ 635,976,672	$ 310,665,448	$ 87,153,037	$ 110,908,477	$ 14,766,461	$ 66,894,125	$ 3,299,456	$ 2,118,269	$ 9,283,733	$ 3,159,067	$ 14,504,137	$ 118,239	$ 8,403,456	$ 2,062,941	$ 641,073	$ 1,998,734
6	Demand Production (Net of 36B Credit)		$ 407,031,518	$ 195,776,105	$ 54,202,425	$ 70,749,549	$ 8,659,373	$ 46,220,562	$ 2,571,970	$ 1,120,918	$ 4,756,476	$ 2,607,021	$ 11,507,234	$ 98,376	$ 6,677,010	$ 877,302	$ 284,750	$ 922,446
7	Demand Transmission		$ 88,928,796	$ 43,014,167	$ 11,850,743	$ 15,009,456	$ 1,826,571	$ 9,797,004	$ 538,588	$ 239,904	$ 950,020	$ 552,067	$ 2,354,840	$ 19,863	$ 1,371,079	$ 1,185,639	$ 51,623	$ 167,232
8	Demand Substation		$ 22,413,542	$ 10,395,070	$ 3,051,605	$ 3,637,285	$ 619,077	$ 2,439,005	$ 188,898	$ 109,547	$ 802,174	$ -	$ 642,063	$ -	$ 355,366	$ -	$ 44,068	$ 129,385
9	Demand Distribution Primary		$ 73,441,392	$ 35,960,959	$ 10,556,796	$ 12,582,914	$ 2,141,651	$ 8,437,554	$ -	$ 378,969	$ 2,775,061	$ -	$ -	$ -	$ -	$ -	$ 152,449	$ 455,039
10	Demand Distribution Secondary		$ 44,161,424	$ 25,519,146	$ 7,491,469	$ 8,929,273	$ 1,519,790	$ -	$ -	$ 268,930	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,183	$ 324,633
11																		
12	**Energy Components**	$ 54,151,345	$ 54,151,345	$ 20,950,398	$ 6,062,720	$ 10,898,622	$ 1,392,144	$ 7,545,394	$ 518,636	$ 155,084	$ 1,229,620	$ 481,552	$ 2,671,669	$ 22,205	$ 1,512,315	$ 278,918	$ 101,916	$ 330,151
13	Energy Fuel		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Energy Non-Fuel		$ 54,151,345	$ 20,950,398	$ 6,062,720	$ 10,898,622	$ 1,392,144	$ 7,545,394	$ 518,636	$ 155,084	$ 1,229,620	$ 481,552	$ 2,671,669	$ 22,205	$ 1,512,315	$ 278,918	$ 101,916	$ 330,151
15																		
16	**Customer Components**	$ 101,509,361	$ 101,509,361	$ 77,334,778	$ 11,621,477	$ 3,402,555	$ 773,383	$ 1,614,346	$ 59,967	$ 242,925	$ 643,583	$ 53,175	$ 269,555	$ 5,463	$ 159,889	$ 30,638	$ 913,716	$ 4,383,912
17	Customer Services		$ 10,697,675	$ 10,250,319	$ 447,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Customer Meter		$ 24,619,918	$ 15,495,273	$ 5,231,776	$ 1,946,985	$ 526,777	$ 694,345	$ 6,118	$ 192,534	$ 501,642	$ 3,059	$ 3,059	$ 3,059	$ 12,235	$ 3,059	$ -	$ -
19	Customer Meter Reading		$ 12,692,226	$ 11,295,413	$ 1,275,047	$ 81,667	$ 22,353	$ 5,479	$ 48	$ 6,066	$ 3,959	$ 24	$ 24	$ 24	$ 97	$ 24	$ -	$ -
20	Customer Billing & Collection		$ 23,548,437	$ 20,982,089	$ 2,098,473	$ 282,942	$ 55,009	$ 110,550	$ 76	$ 12,741	$ 6,253	$ 38	$ 38	$ 38	$ 152	$ 38	$ -	$ -
21	Customer Service and Information		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Customer Other		$ 29,951,104	$ 19,311,684	$ 2,568,825	$ 1,090,962	$ 169,244	$ 803,972	$ 53,725	$ 29,584	$ 131,730	$ 50,054	$ 266,434	$ 2,342	$ 147,404	$ 27,517	$ 913,716	$ 4,383,912
23																		
24																		
25	TOTAL COMPANY	$ 791,637,379	$ 791,637,379	$ 408,950,624	$ 104,837,233	$ 125,209,654	$ 16,931,989	$ 76,053,866	$ 3,878,059	$ 2,516,278	$ 11,156,937	$ 3,693,814	$ 17,445,361	$ 145,907	$ 10,075,660	$ 2,372,497	$ 1,656,705	$ 6,712,797
26																		
27	Total Non-Fuel Revenue Requirements		$ 791,637,379	$ 408,950,624	$ 104,837,233	$ 125,209,654	$ 16,931,989	$ 76,053,866	$ 3,878,059	$ 2,516,278	$ 11,156,937	$ 3,693,814	$ 17,445,361	$ 145,907	$ 10,075,660	$ 2,372,497	$ 1,656,705	$ 6,712,797
28																		
29																		
30	*Target Revenue Requirements at Full Cost of Service*		*$ 791,637,379*	*$ 408,950,624*	*$ 104,837,233*	*$ 125,209,654*	*$ 16,931,989*	*$ 76,053,866*	*$ 3,878,059*	*$ 2,516,278*	*$ 11,156,937*	*$ 3,693,814*	*$ 17,445,361*	*$ 145,907*	*$ 10,075,660*	*$ 2,372,497*	*$ 1,656,705*	*$ 6,712,797*

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PUBLIC SERVICE COMPANY OF NEW MEXICO

PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY-BANDING

NMPRC CASE NO. 16-00276-UT

Line No.	A Description	B Source	C Total	D Schedule 1A/1B Res. 1A/1B	E Schedule 2A/2B Small Power 2A/2B	F Schedule 3B General Power 3B	G Schedule 3C General Power 3C	H Schedule 4B Large Power 4B	I Schedule 5B Large Service>= 8,000kW 5B	J Schedule 10A/10B Irrigat. 10A/10B
1	Revenues at Existing Rates (Non-Fuel)*	*PNM Exhibit SAV-4, p. 135, line 17)*	$ 692,387,504	$ 332,143,835	$ 97,931,024	$ 122,995,870	$ 22,768,915	$ 66,723,164	$ 3,951,210	$ 1,798,513
2										
3	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service	*Pg. 1, L27*	$ 791,637,379	$ 408,950,624	$ 104,837,233	$ 125,209,654	$ 16,931,989	$ 76,053,866	$ 3,878,059	$ 2,516,278
4										
5	Total Non-Fuel Revenue Deficiency Under Equalized ROR	*L3-L1*	$ 99,249,875	$ 76,806,789	$ 6,906,209	$ 2,213,784	$ (5,836,927)	$ 9,330,702	$ (73,151)	$ 717,765
6	% Increase Non-Fuel to Non-Fuel Total	*L5/L1*	14.33%	23.12%	7.05%	1.80%	-25.64%	13.98%	-1.85%	39.91%
7										
8	Upper Band	*110.0%*	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%
9	Lower Band	*88.2%*	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%
10										
11	**Revenue Banding**	*60.00%*								
12	Transitional IIPR Discounts (TIIPR)	*(PNM Exhibit SC-5, Col. F, lines 724-727)*60%*	($965,840)	$0	$0	$0	($61,913)	($68,448)	$0	$0
13	Allocator (Based on Revenue)	*L1 Class/L1 Total (exc. 36B)*	100.00%	48.12%	14.19%	17.82%	3.30%	9.67%	0.57%	0.26%
14	TIIPR Revenue Allocation	*(L12 C)*L13*	$ 965,840	$ 464,766	$ 137,034	$ 172,107	$ 31,860	$ 93,365	$ 5,529	$ 2,517
15	Non-Fuel Revenue Defficiency with TIIPR	*L5+L12+L14*	$ 99,249,875	$ 77,271,555	$ 7,043,243	$ 2,385,891	$ (5,866,979)	$ 9,355,619	$ (67,622)	$ 720,282
16										
17	Banding Adjustment	*(L1*Applicable Band)-L15*	$ 0	$ (24,915,722)	$ 5,331,498	$ 13,156,089	$ 8,744,101	$ -	$ 566,904	$ (436,782)
18	Non-Fuel Revenue Defficiency after Banding	*L5+L17*	$ 99,249,875	$ 51,891,067	$ 12,237,707	$ 15,369,873	$ 2,907,174	$ 9,330,702	$ 493,753	$ 280,983
19	Non-Fuel Revenue Requirements after Banding	*L1+L18*	$ 791,637,379	$ 384,034,902	$ 110,168,731	$ 138,365,743	$ 25,676,089	$ 76,053,866	$ 4,444,963	$ 2,079,496
20	% Increase after Banding	*(L19-L1)/L1*	14.33%	15.62%	12.50%	12.50%	12.77%	13.98%	12.50%	15.62%
21										
22	Final Non-Fuel Revenue Defficiency	*L18*	*$ 99,249,875*	*$ 51,891,067*	*$ 12,237,707*	*$ 15,369,873*	*$ 2,907,174*	*$ 9,330,702*	*$ 493,753*	*$ 280,983*
23	Total Revenue Requirements	*L1+L22*	*$ 791,637,379*	*$ 384,034,902*	*$ 110,168,731*	*$ 138,365,743*	*$ 25,676,089*	*$ 76,053,866*	*$ 4,444,963*	*$ 2,079,496*
24	% Increase of Non-Fuel over Total Non-Fuel	*L22/L1*	*14.33%*	*15.62%*	*12.50%*	*12.50%*	*12.77%*	*13.98%*	*12.50%*	*15.62%*
25										
26	Non-Fuel Revenue Defficiency After Banding With TIIPR Adjustments	*L12+L14+L22*	$ 99,249,875	$ 52,355,833	$ 12,374,741	$ 15,541,980	$ 2,877,121	$ 9,355,619	$499,282	$283,500
27	Final Non-Fuel Revenue Requirements after Banding	*L1+L26*	**$ 791,637,379**	**$ 384,499,668**	**$110,305,765**	**$ 138,537,850**	**$ 25,646,037**	**$ 76,078,783**	**$4,450,492**	**$2,082,013**
28	% Increase After Banding, Including TIIPR	*L26/L1*	14.33%	15.76%	12.64%	12.64%	12.64%	14.02%	12.64%	15.76%
29										
30										
31	*Total Revenue Requirement (w TIIPR Adj. for RD)*	*L27-L12*	*$ 792,603,219*	*$ 384,499,668*	*$ 110,305,765*	*$ 138,537,850*	*$ 25,707,950*	*$ 76,147,231*	*$ 4,450,492*	*$ 2,082,013*
32										
33	*Note: Includes contribution to generation credit.									

PNM EXHIBIT JCA-3
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PUBLIC SERVICE COMPANY OF NEW MEXICO
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY-BANDING
NMPRC CASE NO. 16-00276-UT

Line No.	A Description	B Source	C Total	K Schedule 11B Water & Sewage 11B	L Schedule 15 Univer. 15B	M Schedule 30 Manuf. 30B	N Schedule 33B Station Power 33B	O Schedule 35B Large Power Service >=3,000kW 35B	P Schedule 36B Special Service - Ren. Energy Res. 36B*	Q Schedule 6 Private Lighting 6	R Schedule 20 Street Lighting 20
1	Revenues at Existing Rates (Non-Fuel)*	PNM Exhibit SAV-4, p. 135, line 17)	$ 692,387,504	$ 8,363,040	$ 3,794,036	$ 14,181,934	$ 173,642	$ 5,835,654	$ 2,152,113	$ 2,668,780	$ 6,905,774
2											
3	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service	Pg. 1, L27	$ 791,637,379	$ 11,156,937	$ 3,693,814	$ 17,445,361	$ 145,907	$ 10,075,660	$ 2,372,497	$ 1,656,705	$ 6,712,797
4											
5	Total Non-Fuel Revenue Deficiency Under Equalized ROR	L3-L1	$ 99,249,875	$ 2,793,897	$ (100,223)	$ 3,263,428	$ (27,735)	$ 4,240,006	$ 220,384	$ (1,012,075)	(192,977)
6	% Increase Non-Fuel to Non-Fuel Total	L5/L1	14.33%	33.41%	-2.64%	23.01%	-15.97%	72.66%	10.24%	-37.92%	-2.79%
7											
8	Upper Band	110.0%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%	15.76%
9	Lower Band	88.2%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%	12.64%
10											
11	**Revenue Banding**	60.00%									
12	Transitional IIPR Discounts (TIIPR)	(PNM Exhibit SC-5, Col. F, lines 724-727)*60%	($965,840)	$0	$0	$0	$0	($835,479)	$0	$0	$0
13	Allocator (Based on Revenue)	L1 Class/L1 Total (exc. 36B)	100.00%	1.21%	0.55%	2.05%	0.03%	0.85%	0.00%	0.39%	1.00%
14	TIIPR Revenue Allocation	(L12 C)*L13	$ 965,840	$ 11,702	$ 5,309	$ 19,845	$ 243	$ 8,166	$ -	$ 3,734	$ 9,663
15	Non-Fuel Revenue Deficiency with TIIPR	L5+L12+L14	$ 99,249,875	$ 2,805,599	$ (94,914)	$ 3,283,272	$ (27,492)	$ 3,412,693	$ 220,384	$ (1,008,341)	$ (183,314)
16											
17	Banding Adjustment	(L1*Applicable Band)-L15	$ 0	$ (1,487,333)	$ 574,335	$ (1,491,217)	$ 49,434	$ (2,492,819)	$ -	$ 1,345,573	$ 1,055,940
18	Non-Fuel Revenue Deficiency after Banding	L5+L17	$ 99,249,875	$ 1,306,564	$ 474,112	$ 1,772,210	$ 21,699	$ 1,747,187	$ 220,384	$ 333,497	$ 862,963
19	Non-Fuel Revenue Requirements after Banding	L1+L18	$ 791,637,379	$9,669,604	$4,268,149	$15,954,144	$195,341	$ 7,582,841	$ 2,372,497	$3,002,278	$7,768,736
20	% Increase after Banding	(L19-L1)/L1	14.33%	15.62%	12.50%	12.50%	12.50%	29.94%	10.24%	12.50%	12.50%
21											
22	Final Non-Fuel Revenue Deficiency	L18	$ 99,249,875	$ 1,306,564	$ 474,112	$ 1,772,210	$ 21,699	$ 1,747,187	$ 220,384	$ 333,497	$ 862,963
23	Total Revenue Requirements	L1+L22	$ 791,637,379	$ 9,669,604	$ 4,268,149	$ 15,954,144	$ 195,341	$ 7,582,841	$ 2,372,497	$ 3,002,278	$ 7,768,736
24	% Increase of Non-Fuel over Total Non-Fuel	L22/L1	14.33%	15.62%	12.50%	12.50%	12.50%	29.94%	10.24%	12.50%	12.50%
25											
26	Non-Fuel Revenue Deficiency After Banding With TIIPR Adjustments	L12+L14+L22	$ 99,249,875	$1,318,266	$479,421	$1,792,055	$21,942	$ 919,874	$220,384	$337,232	$872,626
27	Final Non-Fuel Revenue Requirements after Banding	L1+L26	$ 791,637,379	$9,681,306	$4,273,458	$15,973,989	$195,584	$ 6,755,528	$2,372,497	$3,006,012	$7,778,400
28	% Increase After Banding, Including TIIPR	L26/L1	14.33%	15.76%	12.64%	12.64%	12.64%	15.76%	10.24%	12.64%	12.64%
29											
30											
31	*Totol Revenue Requirement (w TIIPR Adj. for RD)*	L27-L12	$ 792,603,219	$ 9,681,306	$ 4,273,458	$ 15,973,989	$ 195,584	$ 7,591,007	$ 2,372,497	$ 3,006,012	$ 7,778,400
32											
33	*Note: Includes contribution to generation credit.										

PNM EXHIBIT JCA-3
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PUBLIC SERVICE COMPANY OF NEW MEXICO
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY- REVENUE REQUIREMENTS AT FULL COST OF SERVICE (AFTER BANDING)
NMPRC CASE NO. 16-00276-UT

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
				Residential	Small Power	General Power	General Power	Large Power	Large Service for Customers >=8,000kW	Irrigation	Wter/Swg Pumping	Universities	Manufacturing	Large Power	Large Power	Special Service	Private Lighting	Streetlighting
			Total	Schedule 1	Schedule 2	Schedule 3B	Schedule 3C	Schedule 4	Schedule 5	Schedule 10	Schedule 11	Schedule 15	Schedule 30	Schedule 33B	Schedule 35B	Schedule 36B	Schedule 6	Schedule 20
			PNM	Residential	Small Power	General Power	General Power LLF	Large Power	Large Service >=8,000kW	Irrigation	Water & Sewage	(Universities 115 kV)	(Manuf, 12.5 kV)	Station Power	Large Power >=3,000kW	Special Service - Renewable Energy Resources	Private Area Lighting	Streetlighting
1	Calculation of Banded Revenue Requirements	Source																
2																		
3																		
4																		
5	**Demand Components**	Sum (L6-L10)	$ 635,887,827	$ 287,759,223	$ 92,265,897	$ 123,044,140	$ 22,786,330	$ 66,978,027	$ 3,794,131	$ 1,713,628	$ 7,980,690	$ 3,662,061	$ 13,261,634	$ 160,062	$ 6,297,753	$ 2,062,941	$ 1,805,295	$ 2,316,017
6	Demand Production	(Pg2 L6)+ [(Pg2 L6)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 406,237,084	$ 181,340,990	$ 57,382,227	$ 78,491,001	$ 13,362,397	$ 46,278,534	$ 2,957,576	$ 906,796	$ 4,088,869	$ 3,022,097	$ 10,521,462	$ 133,173	$ 5,003,913	$ 877,302	$ 801,871	$ 1,068,876
7	Demand Transmission	(Pg2 L7)+ [(Pg2 L7)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 88,670,646	$ 39,842,614	$ 12,545,970	$ 16,651,798	$ 2,818,606	$ 9,809,292	$ 619,337	$ 194,077	$ 816,677	$ 639,964	$ 2,153,112	$ 26,889	$ 1,027,520	$ 1,185,639	$ 145,372	$ 193,778
8	Demand Substation	(Pg2 L8)+ [(Pg2 L8)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 22,414,713	$ 9,628,612	$ 3,230,628	$ 4,035,279	$ 955,307	$ 2,442,064	$ 217,218	$ 88,621	$ 689,583	$ -	$ 587,060	$ -	$ 266,320	$ -	$ 124,097	$ 149,923
9	Demand Distribution Primary	(Pg2 L9)+ [(Pg2 L9)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 73,846,976	$ 33,309,458	$ 11,176,113	$ 13,959,743	$ 3,304,811	$ 8,448,137	$ -	$ 306,577	$ 2,385,560	$ -	$ -	$ -	$ -	$ -	$ 429,305	$ 527,273
10	Demand Distribution Secondary	(Pg2 L10)+ [(Pg2 L10)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 44,718,407	$ 23,637,549	$ 7,930,958	$ 9,906,319	$ 2,345,209	$ -	$ -	$ 217,558	$ -	$ -	$ -	$ -	$ -	$ -	$ 304,649	$ 376,166
11																		
12	**Energy Components**	Sum (L13-L14)	$ 54,510,120	$ 19,405,667	$ 6,418,391	$ 12,091,155	$ 2,148,237	$ 7,554,856	$ 596,394	$ 125,459	$ 1,057,033	$ 558,222	$ 2,442,799	$ 30,059	$ 1,133,365	$ 278,918	$ 287,002	$ 382,559
13	Energy Fuel	(Pg2 L13)+ [(Pg2 L13)/(Pg2 L5+ Pg2 L12)]*(L33)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Energy Non-Fuel	(Pg2 L14)+ [(Pg2 L14)/(Pg2 L5+ Pg2 L12)]*(L33)	$ 54,510,120	$ 19,405,667	$ 6,418,391	$ 12,091,155	$ 2,148,237	$ 7,554,858	$ 596,394	$ 125,459	$ 1,057,033	$ 558,222	$ 2,442,799	$ 30,059	$ 1,133,365	$ 278,918	$ 287,002	$ 382,559
15																		
16	**Customer Components**	Sum (L17-L12)	$ 102,205,272	$ 77,334,778	$ 11,621,477	$ 3,402,555	$ 773,383	$ 1,614,346	$ 59,967	$ 242,925	$ 643,583	$ 53,175	$ 269,555	$ 5,463	$ 159,889	$ 30,638	$ 913,716	$ 5,079,823
17	Customer Services	Pg2, L17	$ 10,697,675	$ 10,250,319	$ 447,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Customer Meter	Pg2, L18	$ 24,619,918	$ 15,495,273	$ 5,231,776	$ 1,946,985	$ 526,777	$ 694,345	$ 6,118	$ 192,534	$ 501,642	$ 3,059	$ 3,059	$ 3,059	$ 12,235	$ 3,059	$ -	$ -
19	Customer Meter Reading	Pg2, L19	$ 12,692,226	$ 11,295,413	$ 1,275,047	$ 81,667	$ 22,353	$ 5,479	$ 48	$ 8,066	$ 3,959	$ 24	$ 24	$ 24	$ 97	$ 24	$ -	$ -
20	Customer Billing & Collection	Pg2, L20	$ 23,548,437	$ 20,962,089	$ 2,098,473	$ 282,942	$ 55,009	$ 110,550	$ 76	$ 12,741	$ 6,253	$ 38	$ 38	$ 38	$ 152	$ 38	$ -	$ -
21	Customer Service and Information	Pg2, L21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Customer Other	Pg2, L22	$ 30,647,015	$ 19,311,684	$ 2,568,825	$ 1,090,962	$ 169,244	$ 803,972	$ 53,725	$ 29,584	$ 131,730	$ 50,054	$ 266,434	$ 2,342	$ 147,404	$ 27,517	$ 913,716	$ 5,079,823
23																		
24																		
25	**Total Company**	L5+L12+L16	$ 792,603,219	$ 384,499,668	$ 110,305,765	$ 138,537,850	$ 25,707,950	$ 76,147,231	$ 4,450,492	$ 2,082,013	$ 9,681,306	$ 4,273,458	$ 15,973,989	$ 195,584	$ 7,591,007	$ 2,372,497	$ 3,006,012	$ 7,778,400
26																		
27																		
28	Total Non-Fuel Revenue Requirements	L25	$ 792,603,219	$ 384,499,668	$ 110,305,765	$ 138,537,850	$ 25,707,950	$ 76,147,231	$ 4,450,492	$ 2,082,013	$ 9,681,306	$ 4,273,458	$ 15,973,989	$ 195,584	$ 7,591,007	$ 2,372,497	$ 3,006,012	7.778,400
29																		
30																		
31	*Target Revenue Requirements (for RD)*	*L28*	*$ 792,603,219*	*$ 384,499,668*	*$ 110,305,765*	*$ 138,537,850*	*$ 25,707,950*	*$ 76,147,231*	*$ 4,450,492*	*$ 2,082,013*	*$ 9,681,306*	*$ 4,273,458*	*$ 15,973,989*	*$ 195,584*	*$ 7,591,007*	*$ 2,372,497*	*$ 3,006,012*	*$ 7,778,400*
32	*Target Revenue Requirements (Inc.TIIPR Discounts)*	*L27 from Pg3&Pg4*	*$ 791,637,379*	*$ 384,499,668*	*$ 110,305,765*	*$ 138,537,850*	*$ 25,646,037*	*$ 76,078,783*	*$ 4,450,492*	*$ 2,082,013*	*$ 9,681,306*	*$ 4,273,458*	*$ 15,973,989*	*$ 195,584*	*$ 6,755,528*	*$ 2,372,497*	*$ 3,006,012*	*$ 7,778,400*
33	Interclass Subsidy	L31-(Pg3&Pg4, L3)	$ 965,840	$ (24,450,956)	$ 5,468,532	$ 13,328,196	$ 8,775,961	$ 93,365	$ 572,433	$ (434,265)	$ (1,475,631)	$ 579,644	$ (1,471,373)	$ 49,677	$ (2,484,653)	$ -	$ 1,349,307	$ 1,065,603
34	% Total Revenue Increase	[L32/(Pg3&Pg4, L1)]-1	***14.334%***	***15.76%***	***12.64%***	***12.64%***	***12.64%***	***14.02%***	***12.64%***	***15.76%***	***15.76%***	***12.64%***	***12.64%***	***12.64%***	***15.76%***	***10.24%***	***12.64%***	***12.64%***
35																		

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PUBLIC SERVICE COMPANY OF NEW MEXICO
PNM CONSOLIDATED CUSTOMER CLASS COST OF SERVICE STUDY- BANDING PHASE I
NMPRC CASE NO. 16-00276-UT

Line	A	B	C	D	E	F	G	H	I	J
			Total	Schedule 1A/1B	Schedule 2A/2B	Schedule 3B	Schedule 3C	Schedule 4B	Schedule 5B	Schedule 10A/10B
No.	Description	Source		Res. 1A/1B	Small Power 2A/2B	General Power 3B	General Power 3C	Large Power 4B	Large Service>= 8,000kW 5B	Irrigat. 10A/10B
1	Revenues at Existing Rates (Non-Fuel)*	*PNM Exhibit SAV-4, p. 135, line 17)*	$ 692,387,504	$ 332,143,835	$ 97,931,024	$ 122,995,870	$ 22,768,915	$ 66,723,164	$ 3,951,210	$ 1,798,513
2										
3	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service	*Pg. 6, L27*	$ 742,387,504	$ 370,837,480	$ 101,410,227	$ 124,111,128	$ 19,828,395	$ 71,423,776	$ 3,914,358	$ 2,160,108
4										
5	Total Non-Fuel Revenue Deficiency Under Equalized ROR	*L3-L1*	$ 50,000,000	$ 38,693,645	$ 3,479,203	$ 1,115,258	$ (2,940,521)	$ 4,700,611	$ (36,852)	$ 361,595
6	% Increase Non-Fuel to Non-Fuel Total	*L5/L1*	7.22%	11.65%	3.55%	0.91%	-12.91%	7.04%	-0.93%	20.11%
7										
8	Upper Band	*110.0%*	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%
9	Lower Band	*88.1%*	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%
10										
11	**Revenue Banding**	*60.00%*								
12	Transitional IIPR Discounts (TIIPR)	*(PNM Exhibit SC-5, Col. F, lines 724-727)*60%*	($965,840)	$0	$0	$0	($61,913)	($68,448)	$0	$0
13	Allocator (Based on Revenue)	*L1 Class/L1 Total (exc. 36B)*	100.00%	48.12%	14.19%	17.82%	3.30%	9.67%	0.57%	0.26%
14	TIIPR Revenue Allocation	*(L12 C)*L13*	$ 965,840	$ 464,766	$ 137,034	$ 172,107	$ 31,860	$ 93,365	$ 5,529	$ 2,517
15	Non-Fuel Revenue Defficiency with TIIPR	*L5+L12+L14*	$ 50,000,000	$ 39,158,411	$ 3,616,237	$ 1,287,365	$ (2,970,574)	$ 4,725,528	$ (31,323)	$ 364,112
16										
17	Banding Adjustment	*(L1*Applicable Band)-L15*	$ (0)	$ (12,779,547)	$ 2,612,346	$ 6,535,386	$ 4,418,716	$ -	$ 282,627	$ (221,274)
18	Non-Fuel Revenue Defficiency after Banding	*L5+L17*	$ 50,000,000	$ 25,914,098	$ 6,091,549	$ 7,650,644	$ 1,478,195	$ 4,700,611	$ 245,775	$ 140,321
19	Non-Fuel Revenue Requirements after Banding	*L1+L18*	$ 742,387,504	$ 358,057,933	$ 104,022,573	$ 130,646,514	$ 24,247,111	$ 71,423,776	$ 4,196,985	$ 1,938,834
20	% Increase after Banding	*(L19-L1)/L1*	7.22%	7.80%	6.22%	6.22%	6.49%	7.04%	6.22%	7.80%
21										
22	Final Non-Fuel Revenue Defficiency	*L18*	*$ 50,000,000*	*$ 25,914,098*	*$ 6,091,549*	*$ 7,650,644*	*$ 1,478,195*	*$ 4,700,611*	*$ 245,775*	*$ 140,321*
23	Total Revenue Requirements	*L1+L22*	*$ 742,387,504*	*$ 358,057,933*	*$ 104,022,573*	*$ 130,646,514*	*$ 24,247,111*	*$ 71,423,776*	*$ 4,196,985*	*$ 1,938,834*
24	% Increase of Non-Fuel over Total Non-Fuel	*L22/L1*	*7.22%*	*7.80%*	*6.22%*	*6.22%*	*6.49%*	*7.04%*	*6.22%*	*7.80%*
25										
26	Non-Fuel Revenue Defficiency After Banding With TIIPR Adjustments	*L12+L14+L22*	$ 50,000,000	$ 26,378,863	$ 6,228,583	$ 7,822,751	$ 1,448,143	$ 4,725,528	$251,304	$142,838
27	Final Non-Fuel Revenue Requirements after Banding	*L1+L26*	$ **742,387,504**	$ **358,522,698**	**$104,159,607**	$ **130,818,621**	$ **24,217,058**	$ **71,448,693**	**$4,202,514**	**$1,941,351**
28	% Increase After Banding, Including TIIPR	*L26/L1*	7.22%	7.94%	6.36%	6.36%	6.36%	7.08%	6.36%	7.94%
29										
30										
31	***Total Revenue Requirement (w TIIPR Adj. for RD)***	*L27-L12*	*$ 743,353,344*	*$ 358,522,698*	*$ 104,159,607*	*$ 130,818,621*	*$ 24,278,971*	*$ 71,517,141*	*$ 4,202,514*	*$ 1,941,351*
32										
33	*Note: Includes contribution to generation credit.									

This schedule sponsored by PNM Witness Aguirre

PNM EXHIBIT JCA-3
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Line No.	A Description	B Source	C Total	K Schedule 11B Water & Sewage 11B	L Schedule 15 Univer. 15B	M Schedule 30 Manuf. 30B	N Schedule 33B Station Power 33B	O Schedule 35B Large Power Service >=3,000kW 35B	P Schedule 36B Special Service - Ren. Energy Res. 36B*	Q Schedule 6 Private Lighting 6	R Schedule 20 Street Lighting 20
1	Revenues at Existing Rates (Non-Fuel)*	*PNM Exhibit SAV-4, p. 135, line 17)*	$ 692,387,504	$ 8,363,040	$ 3,794,036	$ 14,181,934	$ 173,642	$ 5,835,654	$ 2,152,113	$ 2,668,780	$ 6,905,774
2											
3	Proposed Revenue Requirements (Non-Fuel) at Full Cost of Service	*Pg. 6, L27*	$ 742,387,504	$ 9,770,546	$ 3,743,546	$ 15,825,980	$ 159,669	$ 7,971,679	$ 2,263,138	$ 2,158,918	$ 6,808,556
4											
5	Total Non-Fuel Revenue Deficiency Under Equalized ROR	*L3-L1*	$ 50,000,000	$ 1,407,506	$ (50,490)	$ 1,644,046	$ (13,972)	$ 2,136,026	$ 111,025	$ (509,862)	(97,218)
6	% Increase Non-Fuel to Non-Fuel Total	*L5/L1*	7.22%	16.83%	-1.33%	11.59%	-8.05%	36.60%	5.16%	-19.10%	-1.41%
7											
8	Upper Band	*110.0%*	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%	7.94%
9	Lower Band	*88.1%*	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%	6.36%
10											
11	**Revenue Banding**	*60.00%*									
12	Transitional IIPR Discounts (TIIPR)	*(PNM Exhibit SC-5, Col. F, lines 724-727)*60%*	($965,840)	$0	$0	$0	$0	($835,479)	$0	$0	$0
13	Allocator (Based on Revenue)	*L1 Class/L1 Total (exc. 36B)*	100.00%	1.21%	0.55%	2.05%	0.03%	0.85%	0.00%	0.39%	1.00%
14	TIIPR Revenue Allocation	*(L12 C)*L13*	$ 965,840	$ 11,702	$ 5,309	$ 19,845	$ 243	$ 8,166	$ -	$ 3,734	$ 9,663
15	Non-Fuel Revenue Defficiency with TIIPR	*L5+L12+L14*	$ 50,000,000	$ 1,419,209	$ (45,181)	$ 1,663,891	$ (13,729)	$ 1,308,713	$ 111,025	$ (506,128)	$ (87,554)
16											
17	Banding Adjustment	*(L1*Applicable Band)-L15*	$ (0)	$ (755,016)	$ 286,488	$ (761,895)	$ 24,773	$ (845,245)	$ -	$ 675,867	$ 526,774
18	Non-Fuel Revenue Defficiency after Banding	*L5+L17*	$ 50,000,000	$ 652,490	$ 235,998	$ 882,151	$ 10,801	$ 1,290,781	$ 111,025	$ 166,005	$ 429,556
19	Non-Fuel Revenue Requirements after Banding	*L1+L18*	$ 742,387,504	$9,015,530	$4,030,035	$15,064,085	$184,443	$ 7,126,434	$ 2,263,138	$2,834,785	$7,335,330
20	% Increase after Banding	*(L19-L1)/L1*	7.22%	7.80%	6.22%	6.22%	6.22%	22.12%	5.16%	6.22%	6.22%
21											
22	Final Non-Fuel Revenue Defficiency	*L18*	$ 50,000,000	$ 652,490	$ 235,998	$ 882,151	$ 10,801	$ 1,290,781	$ 111,025	$ 166,005	$ 429,556
23	Total Revenue Requirements	*L1+L22*	$ 742,387,504	$ 9,015,530	$ 4,030,035	$ 15,064,085	$ 184,443	$ 7,126,434	$ 2,263,138	$ 2,834,785	$ 7,335,330
24	% Increase of Non-Fuel over Total Non-Fuel	*L22/L1*	7.22%	7.80%	6.22%	6.22%	6.22%	22.12%	5.16%	6.22%	6.22%
25											
26	Non-Fuel Revenue Defficiency After Banding With TIIPR Adjustments	*L12+L14+L22*	$ 50,000,000	$664,193	$241,307	$901,996	$11,044	$ 463,468	$111,025	$169,739	$439,219
27	Final Non-Fuel Revenue Requirements after Banding	*L1+L26*	$ **742,387,504**	**$9,027,233**	**$4,035,344**	**$15,083,929**	**$184,686**	$ **6,299,121**	**$2,263,138**	**$2,838,519**	**$7,344,993**
28	% Increase After Banding, Including TIIPR	*L26/L1*	7.22%	7.94%	6.36%	6.36%	6.36%	7.94%	5.16%	6.36%	6.36%
29											
30											
31	*Total Revenue Requirement (w TIIPR Adj. for RD)*	*L27-L12*	$ 743,353,344	$ 9,027,233	$ 4,035,344	$ 15,083,929	$ 184,686	$ 7,134,600	$ 2,263,138	$ 2,838,519	$ 7,344,993
32											
33	*Note: Includes contribution to generation credit.										

This schedule sponsored by PNM Witness Aguirre

PNM's Rate Design Model for Non-lighting Classes

PNM Exhibit JCA-4

Is contained in the following 14 pages

Schedule: ***1A/1B*** ***Residential Service***

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Source:	SC-5	JCA-3, Page 2, Column D	JCA-3, Page 5, Column D	(D)/(B)			=(M) Total * (Pag. 14, Col. C, L2)	$ 384,092,091		=(M) Total * (Pag. 14, Col. C, L3)	$ 407,577	$ 384,499,668
	Embedded Cost Component						1A			1B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue (Inc. FPPCAC)	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	5,615,569	$ 77,334,778	$ 77,334,778	$ 13.77			$ 13.77	$ 77,306,393		$ 26.10	$ 37,897	$ 77,344,290
2	*Summer*	1,437,857	25.60%		$ 13.77		*Summer*			*Summer*			
3	Customer Services (per customer/per month)		$ 2,624,577	$ 2,624,577	$ 1.83	Customer	1,437,485	$ 13.77	$ 19,794,173	372	$ 20.81	$ 7,731	$ 19,801,904
4	Customer Meter (per customer/per month)		$ 3,967,538	$ 3,967,538	$ 2.76	Meter				372	$ 5.29	$ 1,965	$ 1,965
5	Customer Meter Reading (per customer/per month)		$ 2,892,171	$ 2,892,171	$ 2.01								
6	Customer Billing and Collection (per customer/per month)		$ 5,372,428	$ 5,372,428	$ 3.74								
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
8	Customer Other (per customer/per month)		$ 4,944,724	$ 4,944,724	$ 3.44								
9													
10	*Non-Summer*	4,177,712	74.40%		$ 13.77		*Non-Summer*			*Non-Summer*			
11	Customer Services (per customer/per month)		$ 7,625,742	$ 7,625,742	$ 1.83	Customer	4,176,632	$ 13.77	$ 57,512,220	1,080	$ 20.81	$ 22,485	$ 57,534,705
12	Customer Meter (per customer/per month)		$ 11,527,735	$ 11,527,735	$ 2.76	Meter				1,080	$ 5.29	$ 5,716	$ 5,716
13	Customer Meter Reading (per customer/per month)		$ 8,403,242	$ 8,403,242	$ 2.01								
14	Customer Billing and Collection (per customer/per month)		$ 15,609,661	$ 15,609,661	$ 3.74								
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
16	Customer Other (per customer/per month)		$ 14,366,960	$ 14,366,960	$ 3.44								
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*		$ 310,665,448	$ 287,759,223				$ -	$ -		$ -	$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			*Summer*			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	*Non-Summer (Billable Demand)*						*Non-Summer*			*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	3,164,862,106	$ 20,950,398	$ 19,405,667	$ 0.0061316				$ 306,785,698			$ 369,679	$ 307,155,377
34													
35	Energy Fuel (kWh)		$ -	$ -									
36	Energy Non-Fuel (kWh)		$ 20,950,398	$ 19,405,667									
37													
38	Block 1 Summer (1A)	520,245,451					520,245,451	$ 0.0832830	$ 43,327,578				
39	Block 2 Summer (1A)	255,399,661					255,399,661	$ 0.1221238	$ 31,190,377				
40	Block 3 Summer (1A)	169,309,364					169,309,364	$ 0.1398684	$ 23,681,031				
41	Block 1 Non- Summer (1A)	1,429,514,856					1,429,514,856	$ 0.0832830	$ 119,054,220				
42	Block 2 Non- Summer (1A)	522,833,656					522,833,656	$ 0.1106447	$ 57,848,770				
43	Block 3 Non- Summer (1A)	263,929,600					263,929,600	$ 0.1200461	$ 31,683,723				
44	Summer On-Peak (1B)	271,123								271,123	$ 0.2044460	$ 55,430	$ 55,430
45	Summer Off-Peak (1B)	430,893								430,893	$ 0.0656787	$ 28,301	$ 28,301
46	Non-Summer On-Peak (1B)	1,001,957								1,001,957	$ 0.1591699	$ 159,481	$ 159,481
47	Non-Summer Off-Peak (1B)	1,925,545								1,925,545	$ 0.0656787	$ 126,467	$ 126,467
48													
49													
50	Total		$ 408,950,624	$ 384,499,668					$ 384,092,091			$ 407,576.50	$ 384,499,668

PNM EXHIBIT JCA-4

Schedule: 2A/2B **Small Power Service**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Source:	SC-5	JCA-3 Page 2, Column E	JCA-3, Page 4, Column E	(D)/(B)			=(M) Total * (Pag. 14, Col. C, L6)	$ 108,681,959		=(M) Total * (Pag. 14, Col. C, L7)	$ 1,623,806	$ 110,305,765
	Embedded Cost Component						2A			2B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	633,896	$ 11,621,477	$ 11,621,477	$ 18.33			$ 18.33	$ 11,426,627		$ 18.33	$ 192,685	$ 11,619,312
2	*Summer*	162,294	25.60%		$ 18.33		*Summer*			*Summer*			
3	Customer Services (per customer/per month)		$ 114,535	$ 114,535	$ 0.71	Customer	159,605	$ 18.33	$ 2,925,554	2,690	$ 10.08	$ 27,111	$ 2,952,666
4	Customer Meter (per customer/per month)		$ 1,339,475	$ 1,339,475	$ 8.25	Meter				2,690	$ 8.25	$ 22,189	$ 22,189
5	Customer Meter Reading (per customer/per month)		$ 326,446	$ 326,446	$ 2.01								
6	Customer Billing and Collection (per customer/per month)		$ 537,265	$ 537,265	$ 3.31								
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
8	Customer Other (per customer/per month)		$ 657,688	$ 657,688	$ 4.05								
9													
10	*Non-Summer*	471,602	74.40%		$ 18.33		*Non-Summer*			*Non-Summer*			
11	Customer Services (per customer/per month)		$ 332,821	$ 332,821	$ 0.71	Customer	463,779	$ 18.33	$ 8,501,072	7,822	$ 10.08	$ 78,850	$ 8,579,922
12	Customer Meter (per customer/per month)		$ 3,892,301	$ 3,892,301	$ 8.25	Meter				7,822	$ 8.25	$ 64,535	$ 64,535
13	Customer Meter Reading (per customer/per month)		$ 948,601	$ 948,601	$ 2.01								
14	Customer Billing and Collection (per customer/per month)		$ 1,561,208	$ 1,561,208	$ 3.31								
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
16	Customer Other (per customer/per month)		$ 1,911,137	$ 1,911,137	$ 4.05								
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*		$ 87,153,037	$ 92,265,897				$ -	$ -		$ -	$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			*Summer*			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	*Non-Summer (Billable Demand)*						*Non-Summer*			*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	915,396,797	$ 6,062,720	$ 6,418,391	$ 0.0070116				$ 97,255,333			$ 1,431,121	$ 98,686,453
34													
35	Energy Fuel (kWh)		$ -	$ -									
36	Energy Non-Fuel (kWh)		$ 6,062,720	$ 6,418,391									
37													
38	Summer (2A)	266,128,782					266,128,782	$ 0.1258372	$ 33,488,913				
39	Non-Summer (2A)	636,224,067					636,224,067	$ 0.1002264	$ 63,766,420				
40	Summer On-Peak (2B)	1,389,221								1,389,221	$ 0.2243339	$ 311,649	$ 311,649
41	Summer Off-Peak (2B)	2,338,040								2,338,040	$ 0.0645950	$ 151,026	$ 151,026
42	Non-Summer On-Peak (2B)	3,352,248								3,352,248	$ 0.1739647	$ 583,173	$ 583,173
43	Non-Summer Off-Peak (2B)	5,964,439								5,964,439	$ 0.0645950	$ 385,273	$ 385,273
44													
45	Total		$ 104,837,233	$ 110,305,765					$ 108,681,959			$ 1,623,806	$ 110,305,765

PNM EXHIBIT JCA-4

Schedule: 3B — **General Power Service**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. F	(C)/(B)	JCA-3, Page 5, Column F	(E)/(B)					$ 138,537,850
								3B			
Line No.	Embedded Cost Component	Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	40,601	$ 3,402,555	$ 83.80	$ 3,402,555	$ 83.80			$ 83.80	$ 3,402,392	$ 3,402,392
2	Summer	10,452	25.74%	$ 83.80		$ 83.80		Summer			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -	Pri.	251	$ 83.80	$ 21,069	$ 21,069
4	Customer Meter (per customer/per month)		$ 501,226	$ 47.95	$ 501,226	$ 47.95	Sec.	10,201	$ 83.80	$ 854,833	$ 854,833
5	Customer Meter Reading (per customer/per month)		$ 21,024	$ 2.01	$ 21,024	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 72,840	$ 6.97	$ 72,840	$ 6.97					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 280,854	$ 26.87	$ 280,854	$ 26.87					
9											
10	Non-Summer	30,149	74.26%	$ 83.80		$ 83.80		Non-Summer			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -	Pri.	721	$ 83.80	$ 60,382	$ 60,382
12	Customer Meter (per customer/per month)		$ 1,445,758	$ 47.95	$ 1,445,758	$ 47.95	Sec.	29,428	$ 83.80	$ 2,466,108	$ 2,466,108
13	Customer Meter Reading (per customer/per month)		$ 60,643	$ 2.01	$ 60,643	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 210,102	$ 6.97	$ 210,102	$ 6.97					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 810,108	$ 26.87	$ 810,108	$ 26.87					
17								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
18	Demand Components	4,157,499	$ 110,908,477	$ 26.68	$ 123,044,140	$ 29.60			$ 25.05	$ 104,135,372	$ 104,135,372
19	Summer (Billable Demand)	1,184,705		$ 32.26		$ 35.79		Summer			
20	Demand Production (Summer kW-Month)	37.84%	$ 26,773,875	$ 22.60	$ 29,703,487	$ 25.07	Pri.	65,402	$ 29.35	$ 1,919,560	$ 1,919,560
21	Demand Transmission (Summer kW-Month)	28.50%	$ 4,277,036	$ 3.61	$ 4,745,032	$ 4.01	Sec.	1,119,302	$ 29.68	$ 33,218,984	$ 33,218,984
22	Demand Substation (Summer kW-Month)	28.50%	$ 1,036,467	$ 0.87	$ 1,149,877	$ 0.97					
23	Demand Distribution Primary (Summer kW-Month)	28.50%	$ 3,585,578	$ 3.03	$ 3,977,914	$ 3.36					
24	Demand Distribution Secondary (Summer kW-Month)	28.50%	$ 2,544,451	$ 2.15	$ 2,822,866	$ 2.38					
25											
26	Non-Summer (Billable Demand)	2,972,794		$ 24.45		$ 27.13		Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 43,975,674	$ 14.79	$ 48,787,515	$ 16.41	Pri.	181,145	$ 22.90	$ 4,148,210	$ 4,148,210
28	Demand Transmission (Non-Summer kW-Month)	71.50%	$ 10,732,419	$ 3.61	$ 11,906,766	$ 4.01	Sec.	2,791,650	$ 23.23	$ 64,848,619	$ 64,848,619
29	Demand Substation (Non-Summer kW-Month)	71.50%	$ 2,600,819	$ 0.87	$ 2,885,401	$ 0.97					
30	Demand Distribution Primary (Non-Summer kW-Month)	71.50%	$ 8,997,336	$ 3.03	$ 9,981,829	$ 3.36					
31	Demand Distribution Secondary (Non-Summer kW-Month)	71.50%	$ 6,384,822	$ 2.15	$ 7,083,453	$ 2.38					
32								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
33	Energy Components	1,641,925,784	$ 10,898,622	$ 0.0066377	$ 12,091,155	$ 0.0073640				$ 30,970,938	$ 30,970,938
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 10,898,622		$ 12,091,155						
37								1,641,925,784			
38	Summer On-Peak	206,012,909						206,012,909	$ 0.0294538	$ 6,067,869	$ 6,067,869
39	Summer Off-Peak	269,573,654						269,573,654	$ 0.0137124	$ 3,696,501	$ 3,696,501
40	Non-Summer On-Peak	487,783,611						487,783,611	$ 0.0244000	$ 11,901,943	$ 11,901,943
41	Non-Summer Off-Peak	678,555,610						678,555,610	$ 0.0137124	$ 9,304,624	$ 9,304,624
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 29,149					$ 29,149	$ 29,149
46											
47	Billable RkVA Summer	35,375			$ 9,551	$0.27		35,375	$ 0.27	$ 9,551	$ 9,551
48	Billable RkVA Non-Summer	72,582			$ 19,597	$0.27		72,582	$ 0.27	$ 19,597	$ 19,597
49	Rider 8 Discounts Summer (Sec.)	0			$ -	($6.85)		0	($6.85)	$ -	$ -
50	Rider 8 Discounts Non-Summer (Sec.)	0			$ -	($0.38)		0	($0.38)	$ -	$ -
51	Total		$ 125,209,654		$ 138,537,850					$ 138,537,850	$ 138,537,850
52											

PNM EXHIBIT JCA-4

Schedule: 3C — ***General Power Service (Low Load Factor)***

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. G	(C)/(B)	JCA-3, Page 5, Col. G	(E)/(B)					$ 25,707,950
	Embedded Cost Component							3C			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	11,113	$ 773,383	$ 69.59	$ 773,383	$ 69.59			$ 69.59	$ 773,353	$ 773,353
2	Summer	2,785	25.06%	$ 69.59		$ 69.59		Summer			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -	Pri.	55	$ 69.59	$ 3,846	$ 3,846
4	Customer Meter (per customer/per month)		$ 132,015	$ 47.40	$ 132,015	$ 47.40	Sec.	2,730	$ 69.59	$ 189,963	$ 189,963
5	Customer Meter Reading (per customer/per month)		$ 5,602	$ 2.01	$ 5,602	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 13,786	$ 4.95	$ 13,786	$ 4.95					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 42,414	$ 15.23	$ 42,414	$ 15.23					
9											
10	Non-Summer	8,328	74.94%	$ 69.59		$ 69.59		Non-Summer			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -	Pri.	157	$ 69.59	$ 10,945	$ 10,945
12	Customer Meter (per customer/per month)		$ 394,762	$ 47.40	$ 394,762	$ 47.40	Sec.	8,171	$ 69.59	$ 568,599	$ 568,599
13	Customer Meter Reading (per customer/per month)		$ 16,751	$ 2.01	$ 16,751	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 41,223	$ 4.95	$ 41,223	$ 4.95					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 126,830	$ 15.23	$ 126,830	$ 15.23					
17								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
18	Demand Components	1,055,286	$ 14,766,461	$ 13.99	$ 22,786,330	$ 21.59			$ 9.08	$ 9,579,020	$ 9,579,020
19	Summer (Billable Demand)	298,925		$ 16.75		$ 25.85		Summer			
20	Demand Production (Summer kW-Month)	37.84%	$ 3,276,981	$ 10.96	$ 5,056,755	$ 16.92	Pri.	14,734	$ 10.56	$ 155,593	$ 155,593
21	Demand Transmission (Summer kW-Month)	28.33%	$ 517,402	$ 1.73	$ 798,410	$ 2.67	Sec.	284,190	$ 10.89	$ 3,094,833	$ 3,094,833
22	Demand Substation (Summer kW-Month)	28.33%	$ 175,362	$ 0.59	$ 270,604	$ 0.91					
23	Demand Distribution Primary (Summer kW-Month)	28.33%	$ 606,653	$ 2.03	$ 936,134	$ 3.13					
24	Demand Distribution Secondary (Summer kW-Mont	28.33%	$ 430,502	$ 1.44	$ 664,313	$ 2.22					
25											
26	Non-Summer (Billable Demand)	756,361		$ 12.90		$ 19.91		Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 5,382,391	$ 7.12	$ 8,305,642	$ 10.98	Pri.	52,361	$ 8.06	$ 422,033	$ 422,033
28	Demand Transmission (Non-Summer kW-Month)	71.67%	$ 1,309,169	$ 1.73	$ 2,020,197	$ 2.67	Sec.	704,000	$ 8.39	$ 5,906,561	$ 5,906,561
29	Demand Substation (Non-Summer kW-Month)	71.67%	$ 443,715	$ 0.59	$ 684,703	$ 0.91					
30	Demand Distribution Primary (Non-Summer kW-Mo	71.67%	$ 1,534,998	$ 2.03	$ 2,368,677	$ 3.13					
31	Demand Distribution Secondary (Non-Summer kW-I	71.67%	$ 1,089,288	$ 1.44	$ 1,680,896	$ 2.22					
32								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
33	Energy Components	210,125,160	$ 1,392,144	$ 0.0066253	$ 2,148,237	$ 0.0102236				$ 15,340,046	$ 15,340,046
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 1,392,144		$ 2,148,237						
37											
38	Summer On-Peak	29,517,721						29,517,721	$ 0.1155318	$ 3,410,236	$ 3,410,236
39	Summer Off-Peak	30,823,973						30,823,973	$ 0.0520678	$ 1,604,937	$ 1,604,937
40	Non-Summer On-Peak	72,248,221						72,248,221	$ 0.0870303	$ 6,287,781	$ 6,287,781
41	Non-Summer Off-Peak	77,535,244						77,535,244	$ 0.0520678	$ 4,037,092	$ 4,037,092
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (87,657)					$ (46,382)	$ (46,382)
46											
47	Billable RkVA Summer	15,157			$ 4,092	$0.27		15,157	$ 0.27	$ 4,092	$ 4,092
48	Billable RkVA Non-Summer	42,365			$ 11,438	$0.27		42,365	$ 0.27	$ 11,438	$ 11,438
49	Post-Rider 8 Discounts Summer (Sec.)	12,817			$ (87,793)	($6.85)		12,817	($4.11)	($52,676)	$ (52,676)
50	Post-Rider 8 Discounts Non-Summer (Sec.)	40,513			$ (15,395)	($0.38)		40,513	($0.23)	($9,237)	$ (9,237)
51	Total		$ 16,931,989		$ 25,707,950					$ 25,646,037	$ 25,646,037
52											

PNM EXHIBIT JCA-4

Schedule: 4B **Large Power Service**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. H	(C)/(B)	JCA-3, Page 4, Col. H	(E)/(B)					$ 76,147,231
	Embedded Cost Component								4B		
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	2,724	$ 1,614,346	$ 592.64	$ 1,614,346	$ 592.64			$ 592.64	$ 1,614,351	$ 1,614,351
2	Summer	697	25.59%	$ 592.64		$ 592.64		Summer			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		411	$ 592.64	$ 243,438	$ 243,438
4	Customer Meter (per customer/per month)		$ 177,656	$ 254.90	$ 177,656	$ 254.90	PNMOw-S	286	$ 592.64	$ 169,612	$ 169,612
5	Customer Meter Reading (per customer/per month)		$ 1,402	$ 2.01	$ 1,402	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 28,286	$ 40.58	$ 28,286	$ 40.58					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 205,706	$ 295.14	$ 205,706	$ 295.14					
9											
10	Non-Summer	2,027	74.41%	$ 592.64		$ 592.64		Non-Summer			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		1,205	$ 592.64	$ 714,155	$ 714,155
12	Customer Meter (per customer/per month)		$ 516,689	$ 254.90	$ 516,689	$ 254.90	PNMOw	822	$ 592.64	$ 487,146	$ 487,146
13	Customer Meter Reading (per customer/per month)		$ 4,077	$ 2.01	$ 4,077	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 82,265	$ 40.58	$ 82,265	$ 40.58					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 598,266	$ 295.14	$ 598,266	$ 295.14					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	2,340,344	$ 66,894,125	$ 28.58	$ 66,978,027	$ 28.62			$ 23.84	$ 55,797,607	$ 55,797,607
19	Summer (Billable Demand)	626,741		$ 36.74		$ 36.79		Summer			
20	Demand Production (Summer kW-Month)	37.84%	$ 17,491,328	$ 27.91	$ 17,513,266	$ 27.94		435,274	$ 29.79	$ 12,966,802	$ 12,966,802
21	Demand Transmission (Summer kW-Month)	26.78%	$ 2,623,625	$ 4.19	$ 2,626,916	$ 4.19	PNMOw	191,467	$ 31.23	$ 5,979,649	$ 5,979,649
22	Demand Substation (Summer kW-Month)	26.78%	$ 653,162	$ 1.04	$ 653,982	$ 1.04					
23	Demand Distribution Primary (Summer kW-Month)	26.78%	$ 2,259,566	$ 3.61	$ 2,262,400	$ 3.61					
24	Demand Distribution Secondary (Summer kW-Month)	26.78%	$ -	$ -	$ -	$ -					
25											
26	Non-Summer (Billable Demand)	1,713,603		$ 25.60		$ 25.63		Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 28,729,234	$ 16.77	$ 28,765,268	$ 16.79		1,218,659	$ 21.09	$ 25,701,526	$ 25,701,526
28	Demand Transmission (Non-Summer kW-Month)	73.22%	$ 7,173,380	$ 4.19	$ 7,182,377	$ 4.19	PNMOw	494,943	$ 22.53	$ 11,149,630	$ 11,149,630
29	Demand Substation (Non-Summer kW-Month)	73.22%	$ 1,785,843	$ 1.04	$ 1,788,083	$ 1.04					
30	Demand Distribution Primary (Non-Summer kW-Month)	73.22%	$ 6,177,988	$ 3.61	$ 6,185,737	$ 3.61					
31	Demand Distribution Secondary (Non-Summer kW-Month)	73.22%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	1,106,704,902	$ 7,545,394	$ 0.0068179	$ 7,554,858	$ 0.0068264				$ 18,676,960	$ 18,676,960
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 7,545,394		$ 7,554,858						
37											
38	Summer On-Peak	124,188,276						124,188,276	$ 0.0259765	$ 3,225,983	$ 3,225,983
39	Summer Off-Peak	183,049,039						183,049,039	$ 0.0134909	$ 2,469,492	$ 2,469,492
40	Non-Summer On-Peak	317,918,562						317,918,562	$ 0.0203982	$ 6,484,966	$ 6,484,966
41	Non-Summer Off-Peak	481,549,025						481,549,025	$ 0.0134909	$ 6,496,519	$ 6,496,519
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (55,768)					$ (10,135)	$ (10,135)
46											
47	Billable RkVA Summer	63,920			$ 17,258	$0.27		63,920	$0.27	$ 17,258	$ 17,258
48	Billable RkVA Non-Summer	152,054			$ 41,055	$0.27		152,054	$0.27	$ 41,055	$ 41,055
49	Post-Rider 8 Discounts Summer (Sub)	0			$0	($15.83)		0	($9.50)	$0	$ -
50	Post-Rider 8 Discounts Summer (Pri)	3,887			($61,530)	($15.83)		3,887	($9.50)	($36,918)	$ (36,918)
51	Post-Rider 8 Discounts Non-Summer (Sub)	0			$0	($7.38)		-	($4.43)	$0	$ -
52	Post-Rider 8 Discounts Non-Summer (Pri)	12,880			($52,551)	($4.08)		12,880	($2.45)	($31,530)	$ (31,530)
53											$ -
54											
55	Total		$ 76,053,866		$ 76,147,231					$ 76,078,783	$ 76,078,783

PNM EXHIBIT JCA-4

Schedule: 5B — **Large Service for Customers >= 8,000 kW**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. I	(C)/(B)	JCA-3, Page 5, Col. I	(E)/(B)					$ 4,450,492
	Embedded Cost Component							5B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	24	$ 59,967	$ 2,498.62	$ 59,967	$ 2,498.62			$ 2,498.62	$ 59,967	$ 59,967
2	*Summer*	6	25.59%	$ 2,498.62		$ 2,498.62		*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		6	$ 2,498.62	$ 15,343	$ 15,343
4	Customer Meter (per customer/per month)		$ 1,565	$ 254.90	$ 1,565	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 12	$ 2.01	$ 12	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 20	$ 3.18	$ 20	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 13,746	$ 2,238.54	$ 13,746	$ 2,238.54					
9											
10	*Non-Summer*	18	74.41%	$ 2,498.62		$ 2,498.62		*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		18	$ 2,498.62	$ 44,624	$ 44,624
12	Customer Meter (per customer/per month)		$ 4,552	$ 254.90	$ 4,552	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 36	$ 2.01	$ 36	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 57	$ 3.18	$ 57	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 39,979	$ 2,238.54	$ 39,979	$ 2,238.54					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	192,000	$ 3,299,456	$ 17.18	$ 3,794,131	$ 19.76			$ 17.19	$ 3,299,621	$ 3,299,621
19	*Summer (Billable Demand)*	49,125		$ 23.60		$ 27.14		*Summer*			
20	Demand Production (Summer kW-Month)	37.84%	$ 973,315	$ 19.81	$ 1,119,241	$ 22.78		49,125	$ 23.60	$ 1,159,360	$ 1,159,360
21	Demand Transmission (Summer kW-Month)	25.59%	$ 137,804	$ 2.81	$ 158,465	$ 3.23					$ -
22	Demand Substation (Summer kW-Month)	25.59%	$ 48,332	$ 0.98	$ 55,578	$ 1.13					
23	Demand Distribution Primary (Summer kW-Month)	25.59%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	25.59%	$ -	$ -	$ -	$ -					
25											
26	*Non-Summer (Billable Demand)*	142,875		$ 14.98		$ 17.22		*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 1,598,655	$ 11.19	$ 1,838,335	$ 12.87		142,875	$ 14.98	$ 2,140,261	$ 2,140,261
28	Demand Transmission (Non-Summer kW-Month)	74.41%	$ 400,784	$ 2.81	$ 460,872	$ 3.23					$ -
29	Demand Substation (Non-Summer kW-Month)	74.41%	$ 140,566	$ 0.98	$ 161,641	$ 1.13					
30	Demand Distribution Primary (Non-Summer kW-Month)	74.41%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	74.41%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	70,596,567	$ 518,636	$ 0.0073465	$ 596,394	$ 0.0084479				$ 1,083,750	$ 1,083,750
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 518,636		$ 596,394						
37											
38	Summer On-Peak	7,245,481						7,245,481	$ 0.0267113	$ 193,536	$ 193,536
39	Summer Off-Peak	11,600,913						11,600,913	$ 0.0118369	$ 137,319	$ 137,319
40	Non-Summer On-Peak	19,415,531						19,415,531	$ 0.0190647	$ 370,151	$ 370,151
41	Non-Summer Off-Peak	32,334,642						32,334,642	$ 0.0118369	$ 382,744	$ 382,744
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 7,154					$ 7,154	$ 7,154
46											
47	Billable RkVA Summer	4,992			$ 1,348	$0.27		4,992	$0.27	$ 1,348	$ 1,348
48	Billable RkVA Non-Summer	21,503			$ 5,806	$0.27		21,503	$0.27	$ 5,806	$ 5,806
49											$ -
50											$ -
51											$ -
52											$ -
53	Total		$ 3,878,059		$ 4,450,492					$ 4,450,492	$ 4,450,492

PNM EXHIBIT JCA-4

Schedule: 10A/10B **Irrigation Service**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Source:	SC-5	JCA-3, Page 2, Col. J	JCA-3, Page 5, Col. J	(D)/(B)			=(M) Total * (Pag. 14, Col. C, L10)	$ 363,366		=(M) Total * (Pag. 14, Col. C, L11)	$ 1,718,646	$ 2,082,013
	Embedded Cost Component						10A			10B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	4,010	$ 242,925	$ 242,925	$ 60.58			$ 18.33	$ 26,193		$ 18.33	$ 47,309	$ 73,502
2	*Summer*	1,027	25.62%		$ 60.58		*Summer*			*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	Customer	366	$ 18.33	$ 6,713	661	$ 12.57	$ 8,306	$ 15,019
4	Customer Meter (per customer/per month)		$ 49,319	$ 49,319	$ 48.01	Meter				661	$ 5.76	$ 3,810	$ 3,810
5	Customer Meter Reading (per customer/per month)		$ 2,066	$ 2,066	$ 2.01								
6	Customer Billing and Collection (per customer/per month)		$ 3,264	$ 3,264	$ 3.18								
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
8	Customer Other (per customer/per month)		$ 7,578	$ 7,578	$ 7.38								
9													
10	*Non-Summer*	2,983	74.38%		$ 60.58		*Non-Summer*			*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	Customer	1,063	$ 18.33	$ 19,480	1,920	$ 12.57	$ 24,128	$ 43,608
12	Customer Meter (per customer/per month)		$ 143,215	$ 143,215	$ 48.01	Meter				1,920	$ 5.76	$ 11,066	$ 11,066
13	Customer Meter Reading (per customer/per month)		$ 6,000	$ 6,000	$ 2.01								
14	Customer Billing and Collection (per customer/per month)		$ 9,477	$ 9,477	$ 3.18								
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -								
16	Customer Other (per customer/per month)		$ 22,006	$ 22,006	$ 7.38								
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*		$ 2,118,269	$ 1,713,628					$ -			$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			*Summer*			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	*Non-Summer (Billable Demand)*						*Non-Summer*			*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	23,427,777	$ 155,084	$ 125,459	$ 0.0053551				$ 337,173			$ 1,671,337	$ 2,008,510
34													
35	Energy Fuel (kWh)		$ -	$ -									
36	Energy Non-Fuel (kWh)		$ 155,084	$ 125,459									
37							3,997,323						
38	Summer (10A)	1,696,099					1,696,099	$ 0.0888863	$ 150,760				
39	Non-Summer (10A)	2,301,224				9.7%	2,301,224	$ 0.0810062	$ 186,413	19,430,454			
40	Summer On-Peak (10B)	2,900,445								2,900,445	$ 0.1366551	$ 396,361	$ 396,361
41	Summer Off-Peak (10B)	5,199,480								5,199,480	$ 0.0622354	$ 323,592	$ 323,592
42	Non-Summer On-Peak (10B)	3,917,891								3,917,891	$ 0.1250816	$ 490,056	$ 490,056
43	Non-Summer Off-Peak (10B)	7,412,637								7,412,637	$ 0.0622354	$ 461,329	$ 461,329
44													
45	Total		$ 2,516,278	$ 2,082,013					$ 363,366			$ 1,718,646	$ 2,082,013

PNM EXHIBIT JCA-4

Schedule: 11B Water and Sewage Pumping Service

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Source:	SC-5	JCA-3, Page 2, Col. K	JCA-3, Page 5, Col. K	(D)/(B)					$ 9,681,306
	Embedded Cost Component						11B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	*1,968*	*$ 643,583*	*$ 643,583*	*$ 327.02*			*$ 327.02*	*$ 643,583*	*$ 643,583*
2	*Summer*	504	25.59%		$ 327.02		*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -		504	*$ 327.02*	$ 164,668	$ 164,668
4	Customer Meter (per customer/per month)		$ 128,351	$ 128,351	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 1,013	$ 1,013	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 1,600	$ 1,600	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 33,705	$ 33,705	$ 66.94					
9										
10	*Non-Summer*	1,464	74.41%		$ 327.02		*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -		1,464	*$ 327.02*	$ 478,915	$ 478,915
12	Customer Meter (per customer/per month)		$ 373,291	$ 373,291	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 2,946	$ 2,946	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 4,653	$ 4,653	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 98,026	$ 98,026	$ 66.94					
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*		*$ 9,283,733*	*$ 7,980,690*	*$ -*				*$ -*	*$ -*
19	*Summer (Billable Demand)*				$ -		*Summer*			
20	Demand Production (Summer kW-Month)				$ -				$ -	$ -
21	Demand Transmission (Summer kW-Month)				$ -					$ -
22	Demand Substation (Summer kW-Month)				$ -					
23	Demand Distribution Primary (Summer kW-Month)				$ -					
24	Demand Distribution Secondary (Summer kW-Month)				$ -					
25										
26	*Non-Summer (Billable Demand)*				$ -		*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)				$ -				$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)				$ -					$ -
29	Demand Substation (Non-Summer kW-Month)				$ -					
30	Demand Distribution Primary (Non-Summer kW-Month)				$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)				$ -					
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	*168,508,457*	*$ 1,229,620*	*$ 1,057,033*	*$ 0.0062729*				*$ 9,037,723*	*$ 9,037,723*
34										
35	Energy Fuel (kWh)		$ -	$ -						
36	Energy Non-Fuel (kWh)		$ 1,229,620	$ 1,057,033						
37										
38	Summer On-Peak	12,600,011					12,600,011	*$ 0.1644427*	$ 2,071,980	$ 2,071,980
39	Summer Off-Peak	40,775,401					40,775,401	*$ 0.0317462*	$ 1,294,466	$ 1,294,466
40	Non-Summer On-Peak	27,170,788					27,170,788	*$ 0.1059522*	$ 2,878,806	$ 2,878,806
41	Non-Summer Off-Peak	87,962,256					87,962,256	*$ 0.0317462*	$ 2,792,471	$ 2,792,471
42										
43										
44		Billing Units (Test Year)		Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits			$ -					$ -	$ -
46										
47										$ -
48										$ -
49										$ -
50	Total		*$ 11,156,937*	*$ 9,681,306*					*$ 9,681,306*	*$ 9,681,306*

PNM EXHIBIT JCA-4

Schedule: 15B — **Large Service for Public Universities**

Embedded Cost Component

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. L	(C)/(B)	JCA-3, Page 5, Col. L	(E)/(B)					$ 4,273,458
								15B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	12	$ 53,175	$ 4,431.22	$ 53,175	$ 4,431.22			$ 4,431.00	$ 53,172	$ 53,172
2	Summer	3	25.59%	$ 4,431.22		$ 4,431.22		Summer			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		3	$ 4,431.00	$ 13,293	$ 13,293
4	Customer Meter (per customer/per month)		$ 783	$ 254.90	$ 783	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 6	$ 2.01	$ 6	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 10	$ 3.18	$ 10	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 12,807	$ 4,171.13	$ 12,807	$ 4,171.13					
9											
10	Non-Summer	9	74.41%	$ 4,431.22		$ 4,431.22		Non-Summer			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		9	$ 4,431.00	$ 39,879	$ 39,879
12	Customer Meter (per customer/per month)		$ 2,276	$ 254.90	$ 2,276	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 18	$ 2.01	$ 18	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 28	$ 3.18	$ 28	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 37,247	$ 4,171.13	$ 37,247	$ 4,171.13					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	202,478	$ 3,159,087	$ 15.60	$ 3,662,061	$ 18.09			$ 15.35	$ 3,108,526	$ 3,108,526
19	Summer (Billable Demand)	56,320		$ 20.24		$ 23.47		Summer			
20	Demand Production (Summer kW-Month)	37.84%	$ 986,579	$ 17.52	$ 1,143,658	$ 20.31		56,320	$ 20.01	$ 1,127,203	$ 1,127,203
21	Demand Transmission (Summer kW-Month)	27.82%	$ 153,560	$ 2.73	$ 178,009	$ 3.16					$ -
22	Demand Substation (Summer kW-Month)	27.82%	$ -	$ -	$ -	$ -					
23	Demand Distribution Primary (Summer kW-Month)	27.82%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	27.82%	$ -	$ -	$ -	$ -					
25											
26	Non-Summer (Billable Demand)	146,158		$ 13.81		$ 16.01		Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 1,620,441	$ 11.09	$ 1,878,440	$ 12.85		146,158	$ 13.56	$ 1,981,323	$ 1,981,323
28	Demand Transmission (Non-Summer kW-Month)	72.18%	$ 398,507	$ 2.73	$ 461,955	$ 3.16					$ -
29	Demand Substation (Non-Summer kW-Month)	72.18%	$ -	$ -	$ -	$ -					
30	Demand Distribution Primary (Non-Summer kW-Month)	72.18%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.18%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	63,683,882	$ 481,552	$ 0.0075616	$ 558,222	$ 0.0087655				$ 1,061,198	$ 1,061,198
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 481,552		$ 558,222						
37											
38	Summer On-Peak	8,298,219						8,298,219	$ 0.0288527	$ 239,426	$ 239,426
39	Summer Off-Peak	12,620,849						12,620,849	$ 0.0115184	$ 145,372	$ 145,372
40	Non-Summer On-Peak	16,661,882						16,661,882	$ 0.0225507	$ 375,736	$ 375,736
41	Non-Summer Off-Peak	26,102,931						26,102,931	$ 0.0115184	$ 300,664	$ 300,664
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 50,561					$ 50,561	$ 50,561
46											
47	Contract Facility Charge Summer	16,801			$ 12,937	$0.77		16,801	$ 0.77	$ 12,937	$ 12,937
48	Contract Facility Charge Non-Summer	48,863			$ 37,625	$0.77		48,863	$ 0.77	$ 37,625	$ 37,625
49	Billable RkVA Summer	0			$ -	$0.27		0	$0.27	$ -	$ -
50	Billable RkVA Non-Summer	0			$ -	$0.27		0	$0.27	$ -	$ -
51											$ -
52											$ -
53	Total		$ 3,693,814		$ 4,273,458					$ 4,273,458	$ 4,273,458

PNM EXHIBIT JCA-4

Schedule: 30B — **Large Service for Manufacturing**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. M	(C)/(B)	JCA-3, Page 5, Col. M	(E)/(B)					$ 15,973,989
	Embedded Cost Component							30B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	12	$ 269,555	$ 22,462.95	$ 269,555	$ 22,462.95			$ 22,462.95	$ 269,555	$ 269,555
2	Summer	3	25.59%	$ 22,462.95		$ 22,462.95		Summer			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		3	$ 22,462.95	$ 67,389	$ 67,389
4	Customer Meter (per customer/per month)		$ 783	$ 254.90	$ 783	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 6	$ 2.01	$ 6	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 10	$ 3.18	$ 10	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 68,170	$ 22,202.87	$ 68,170	$ 22,202.87					
9											
10	Non-Summer	9	74.41%	$ 22,462.95		$ 22,462.95		Non-Summer			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		9	$ 22,462.95	$ 202,167	$ 202,167
12	Customer Meter (per customer/per month)		$ 2,276	$ 254.90	$ 2,276	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 18	$ 2.01	$ 18	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 28	$ 3.18	$ 28	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 198,264	$ 22,202.87	$ 198,264	$ 22,202.87					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	502,944	$ 14,504,137	$ 28.84	$ 13,261,634	$ 26.37			$ 25.72	$ 12,933,841	$ 12,933,841
19	Summer (Billable Demand)	128,684		$ 39.80		$ 36.39		Summer			
20	Demand Production (Summer kW-Month)	37.84%	$ 4,354,703	$ 33.84	$ 3,981,655	$ 30.94		128,684	$ 33.84	$ 4,354,967	$ 4,354,967
21	Demand Transmission (Summer kW-Month)	25.59%	$ 602,513	$ 4.68	$ 550,899	$ 4.28					$ -
22	Demand Substation (Summer kW-Month)	25.59%	$ 164,279	$ 1.28	$ 150,206	$ 1.17					
23	Demand Distribution Primary (Summer kW-Month)	25.59%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	25.59%	$ -	$ -	$ -	$ -					
25											
26	Non-Summer (Billable Demand)	374,260		$ 25.07		$ 22.92		Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 7,152,531	$ 19.11	$ 6,539,807	$ 17.47		374,260	$ 22.92	$ 8,578,874	$ 8,578,874
28	Demand Transmission (Non-Summer kW-Month)	74.41%	$ 1,752,327	$ 4.68	$ 1,602,213	$ 4.28					$ -
29	Demand Substation (Non-Summer kW-Month)	74.41%	$ 477,783	$ 1.28	$ 436,854	$ 1.17					
30	Demand Distribution Primary (Non-Summer kW-Month)	74.41%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	74.41%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	363,666,494	$ 2,671,669	$ 0.0073465	$ 2,442,799	$ 0.0067171				$ 2,758,203	$ 2,758,203
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 2,671,669		$ 2,442,799						
37											
38	Summer On-Peak	33,295,199						33,295,199	$ 0.0124051	$ 413,030	$ 413,030
39	Summer Off-Peak	59,708,151						59,708,151	$ 0.0060525	$ 361,381	$ 361,381
40	Non-Summer On-Peak	96,897,406						96,897,406	$ 0.0096193	$ 932,084	$ 932,084
41	Non-Summer Off-Peak	173,765,738						173,765,738	$ 0.0060525	$ 1,051,709	$ 1,051,709
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 12,389					$ 12,389	$ 12,389
46											
47	Billable RkVA Summer	11,892			$ 3,211	$0.27		11,892	$0.27	$ 3,211	$ 3,211
48	Billable RkVA Non-Summer	33,993			$ 9,178	$0.27		33,993	$0.27	$ 9,178	$ 9,178
49											$ -
50											$ -
51											$ -
52											$ -
53	Total		$ 17,445,361		$ 15,973,989					$ 15,973,989	$ 15,973,989

PNM EXHIBIT JCA-4

Schedule: 33B — Large Service for Station Power

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. N	(C)/(B)	JCA-3, Page 5, Col. N	(E)/(B)					$ 195,584
	Embedded Cost Component							33B			
Line No.		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	12	$ 5,463	$ 455.23	$ 5,463	$ 455.23			$ 455.23	$ 5,463	$ 5,463
2	*Summer*	3	25.59%	$ 455.23		$ 455.23		*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		3	$ 455.23	$ 1,366	$ 1,366
4	Customer Meter (per customer/per month)		$ 783	$ 254.90	$ 783	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 6	$ 2.01	$ 6	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 10	$ 3.18	$ 10	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 599	$ 195.15	$ 599	$ 195.15					
9											
10	*Non-Summer*	9	74.41%	$ 455.23		$ 455.23		*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		9	$ 455.23	$ 4,097	$ 4,097
12	Customer Meter (per customer/per month)		$ 2,276	$ 254.90	$ 2,276	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 18	$ 2.01	$ 18	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 28	$ 3.18	$ 28	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 1,743	$ 195.15	$ 1,743	$ 195.15					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	21,021	$ 118,239	$ 5.62	$ 160,062	$ 7.61			$ 5.62	$ 118,239	$ 118,239
19	*Summer (Billable Demand)*	5,495		$ 7.72		$ 10.45		*Summer*			
20	Demand Production (Summer kW-Month)	37.84%	$ 37,229	$ 6.77	$ 50,397	$ 9.17		5,495	$ 7.72	$ 42,421	$ 42,421
21	Demand Transmission (Summer kW-Month)	26.14%	$ 5,193	$ 0.94	$ 7,029	$ 1.28					$ -
22	Demand Substation (Summer kW-Month)	26.14%	$ -	$ -	$ -	$ -					
23	Demand Distribution Primary (Summer kW-Month)	26.14%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	26.14%	$ -	$ -	$ -	$ -					
25											
26	*Non-Summer (Billable Demand)*	15,526		$ 4.88		$ 6.61		*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 61,147	$ 3.94	$ 82,776	$ 5.33		15,526	$ 4.88	$ 75,818	$ 75,818
28	Demand Transmission (Non-Summer kW-Month)	73.86%	$ 14,670	$ 0.94	$ 19,859	$ 1.28					$ -
29	Demand Substation (Non-Summer kW-Month)	73.86%	$ -	$ -	$ -	$ -					
30	Demand Distribution Primary (Non-Summer kW-Month)	73.86%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	73.86%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	3,354,394	$ 22,205	$ 0.0066197	$ 30,059	$ 0.0089611				$ 38,232	$ 38,232
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 22,205		$ 30,059						
37											
38	Summer On-Peak	280,644						280,644	$ 0.0182298	$ 5,116	$ 5,116
39	Summer Off-Peak	581,919						581,919	$ 0.0090332	$ 5,257	$ 5,257
40	Non-Summer On-Peak	914,064						914,064	$ 0.0148863	$ 13,607	$ 13,607
41	Non-Summer Off-Peak	1,577,767						1,577,767	$ 0.0090332	$ 14,252	$ 14,252
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 33,650					$ 33,650	$ 33,650
46											
47	Billable RkVA Summer	6,014			$ 1,624	$0.27		6,014	$0.27	$ 1,624	$ 1,624
48	Billable RkVA Non-Summer	118,615			$ 32,026	$0.27		118,615	$0.27	$ 32,026	$ 32,026
49	Total		$ 145,907		$ 195,584					$ 195,584	$ 195,584

Schedule: 35B **Large Power Service >=3,000 kW**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. O	(C)/(B)	JCA-3, Page 5, Col. O	(E)/(B)					$ 7,591,007
	Embedded Cost Component								35B		
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	48	$ 159,889	$ 3,331.01	$ 159,889	$ 3,331.01			$ 3,331.01	$ 159,888	$ 159,888
2	*Summer*	12	25.59%	$ 3,331.01		$ 3,331.01		*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		12	$ 3,331.01	$ 39,972	$ 39,972
4	Customer Meter (per customer/per month)		$ 3,131	$ 254.90	$ 3,131	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 25	$ 2.01	$ 25	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 39	$ 3.18	$ 39	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 37,715	$ 3,070.93	$ 37,715	$ 3,070.93					
9											
10	*Non-Summer*	36	74.41%	$ 3,331.01		$ 3,331.01		*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		36	$ 3,331.01	$ 119,916	$ 119,916
12	Customer Meter (per customer/per month)		$ 9,105	$ 254.90	$ 9,105	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 72	$ 2.01	$ 72	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 113	$ 3.18	$ 113	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 109,689	$ 3,070.93	$ 109,689	$ 3,070.93					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	305,369	$ 8,403,456	$ 27.52	$ 6,297,753	$ 20.62			$ 20.62	$ 6,297,753	$ 6,297,753
19	*Summer (Billable Demand)*	83,120		$ 36.05		$ 27.02		*Summer*			
20	Demand Production (Summer kW-Month)	37.84%	$ 2,526,793	$ 30.40	$ 1,893,639	$ 22.78		83,120	$ 27.02	$ 2,245,817	$ 2,245,817
21	Demand Transmission (Summer kW-Month)	27.22%	$ 373,202	$ 4.49	$ 279,686	$ 3.36					$ -
22	Demand Substation (Summer kW-Month)	27.22%	$ 96,729	$ 1.16	$ 72,491	$ 0.87					
23	Demand Distribution Primary (Summer kW-Month)	27.22%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	27.22%	$ -	$ -	$ -	$ -					
25											
26	*Non-Summer (Billable Demand)*	222,249		$ 24.33		$ 18.23		*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ 4,150,218	$ 18.67	$ 3,110,273	$ 13.99		222,249	$ 18.23	$ 4,051,936	$ 4,051,936
28	Demand Transmission (Non-Summer kW-Month)	72.78%	$ 997,877	$ 4.49	$ 747,833	$ 3.36					$ -
29	Demand Substation (Non-Summer kW-Month)	72.78%	$ 258,637	$ 1.16	$ 193,829	$ 0.87					
30	Demand Distribution Primary (Non-Summer kW-Month)	72.78%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.78%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	205,855,705	$ 1,512,315	$ 0.0073465	$ 1,133,365	$ 0.0055056				$ 1,128,793	$ 1,128,793
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 1,512,315		$ 1,133,365						
37											
38	Summer On-Peak	18,487,920						18,487,920	$ 0.0087851	$ 162,419	$ 162,419
39	Summer Off-Peak	37,376,551						37,376,551	$ 0.0045625	$ 170,532	$ 170,532
40	Non-Summer On-Peak	47,732,027						47,732,027	$ 0.0068986	$ 329,282	$ 329,282
41	Non-Summer Off-Peak	102,259,207						102,259,207	$ 0.0045625	$ 466,561	$ 466,561
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (1,387,892)					$ (830,907)	$ (830,907)
46											
47	Billable RkVA Summer	5,373			$ 1,451	$0.27		5,373	$0.27	$ 1,451	$ 1,451
48	Billable RkVA Non-Summer	11,561			$ 3,121	$0.27		11,561	$0.27	$ 3,121	$ 3,121
49	Post-Rider 8 Discounts Summer (Sub)	36,819			($582,839)	($15.83)		36,819	($9.50)	($349,703)	$ (349,703)
50	Post-Rider 8 Discounts Summer (Pri)	0			$0	($15.83)		0	($9.50)	$0	$ -
51	Post-Rider 8 Discounts Non-Summer (Sub)	109,705			($809,626)	($7.38)		109,705	($4.43)	($485,775)	$ (485,775)
52	Post-Rider 8 Discounts Non-Summer (Pri)	0			$0	($4.08)		0	($2.45)	$0	$ -
53											
54	Total		$ 10,075,660		$ 7,591,007					$ 6,755,528	$ 6,755,528

PNM EXHIBIT JCA-4

Schedule: 36B — ***Special Service -Renewable Energy Resources***

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5	JCA-3, Page 2, Col. P	(C)/(B)	JCA-3, Page 5, Col. P	(E)/(B)					$ 2,372,497
	Embedded Cost Component							35B			
Line No.		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	12	$ 30,638	$ 2,553.13	$ 30,638	$ 2,553.13			$ 2,553.13	$ 30,638	$ 30,638
2	*Summer*	3	25.00%	$ 2,553.13		$ 2,553.13		*Summer*			
3	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		3	$ 2,553.13	$ 7,659	$ 7,659
4	Customer Meter (per customer/per month)		$ 765	$ 254.90	$ 765	$ 254.90					$ -
5	Customer Meter Reading (per customer/per month)		$ 6	$ 2.01	$ 6	$ 2.01					
6	Customer Billing and Collection (per customer/per month)		$ 10	$ 3.18	$ 10	$ 3.18					
7	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
8	Customer Other (per customer/per month)		$ 6,879	$ 2,293.05	$ 6,879	$ 2,293.05					
9											
10	*Non-Summer*	9	75.00%	$ 2,553.13		$ 2,553.13		*Non-Summer*			
11	Customer Services (per customer/per month)		$ -	$ -	$ -	$ -		9	$ 2,553.13	$ 22,978	$ 22,978
12	Customer Meter (per customer/per month)		$ 2,294	$ 254.90	$ 2,294	$ 254.90					$ -
13	Customer Meter Reading (per customer/per month)		$ 18	$ 2.01	$ 18	$ 2.01					
14	Customer Billing and Collection (per customer/per month)		$ 29	$ 3.18	$ 29	$ 3.18					
15	Customer Service and Information (per customer/per month)		$ -	$ -	$ -	$ -					
16	Customer Other (per customer/per month)		$ 20,637	$ 2,293.05	$ 20,637	$ 2,293.05					
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	268,700	$ 1,185,639	$ 4.41	$ 1,185,639	$ 4.41			$ 4.41	$ 1,185,639	$ 1,185,639
19	*Summer (Billable Demand)*	74,500		$ 4.41		$ 4.41		*Summer*			
20	Demand Production (Summer kW-Month)	37.84%	$ -	$ -	$ -	$ -		74,500	$ 4.41	$ 328,731	$ 328,731
21	Demand Transmission (Summer kW-Month)	27.73%	$ 328,731	$ 4.41	$ 328,731	$ 4.41					$ -
22	Demand Substation (Summer kW-Month)	27.73%	$ -	$ -	$ -	$ -					
23	Demand Distribution Primary (Summer kW-Month)	27.73%	$ -	$ -	$ -	$ -					
24	Demand Distribution Secondary (Summer kW-Month)	27.73%	$ -	$ -	$ -	$ -					
25											
26	*Non-Summer (Billable Demand)*	194,200		$ 4.41		$ 4.41		*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%	$ -	$ -	$ -	$ -		194,200	$ 4.41	$ 856,908	$ 856,908
28	Demand Transmission (Non-Summer kW-Month)	72.27%	$ 856,908	$ 4.41	$ 856,908	$ 4.41					$ -
29	Demand Substation (Non-Summer kW-Month)	72.27%	$ -	$ -	$ -	$ -					
30	Demand Distribution Primary (Non-Summer kW-Month)	72.27%	$ -	$ -	$ -	$ -					
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.27%	$ -	$ -	$ -	$ -					
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	37,966,258	$ 278,918	$ 0.0073465	$ 278,918	$ 0.0073465				$ 278,918	$ 278,918
34											
35	Energy Fuel (kWh)		$ -		$ -						
36	Energy Non-Fuel (kWh)		$ 278,918		$ 278,918						
37											
38	Summer	8,398,339	$ 61,698	0.0073465	$ 61,698	$ 0.0073465		8,398,339	$ 0.0073465	$ 61,698	$ 61,698
39											$ -
40	Non-Summer	29,567,919	$ 217,220	0.0073465	$ 217,220	$ 0.0073465		29,567,919	$ 0.0073465	$ 217,220	$ 217,220
41											$ -
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 877,302					$ 877,302	$ 877,302
46											
47											
48											
49											
50	Contribution to Generation Credit	37,966,258			$ 877,302	$ 0.0231074		37,966,258	$ 0.0231074	$ 877,302	
51											
52											
53											
54	Total		$ 1,495,195		$ 1,495,195					$ 2,372,497	$ 2,372,497

PNM EXHIBIT JCA-4

Calculation of Revenue Ratios for Optional TOU Schedules

Line No.	A	B		C	D
1	Rate Schedule	Test Period Revenue Under Existing Rates		% of Rate Class Total	Source : PNM Exhibit SC-5
2	1A	$	331,768,507	99.89%	Lines 11-14
3	1B	$	375,328	0.11%	Lines 27-30
4	Total	$	332,143,835	100.00%	
5					
6	2A	$	96,479,005	98.53%	Lines 39-40
7	2B	$	1,065,276	1.47%	Lines 53-56
8	Total	$	97,544,281	100.00%	
9					
10	10A	$	313,888	17.45%	Lines 219-220
11	10B	$	1,484,625	82.55%	Lines 233-236
12	Total	$	1,798,513	100.00%	
13					

Calculation of Fuel Rates Based on Revised Voltage Class Adjustment Factors

PNM Exhibit JCA-5

Is contained in the following 4 pages

Calculation of Fuel Rates based on Revised Voltage Class Adjustment Factors - Test Period Proof of Revenue

Line No.	Description	Value	Notes
1	Fuel Costs	$ 140,986,737	[A]
2	Consolidated kWh at Meter (Non-Renewable)	7,161,364,736	[B]
3	Average Fuel Rate	$0.0196871	[C] = [A] / [B]

Consolidated Class Fuel Allocations

Line No.	Rate Class	Voltage Class	Consolidated kWh at Meter (Non-Renewable) page 2, Col. C, Rows 17-32 [D]	Cumulative Loss Factor [E]	Consolidated kWh at Generator [F] = [D] * [E]	Voltage Class Adjustment Factors [G] = [E] / [E] $_{TOTAL}$	Fuel Rate per kWh [H] = [C] * [G]	Fuel Revenue by Rate Class [I] = [D] * [H]
4	1 - Residential	Sec. Dist	2,770,631,819	1.0979	3,041,887,685	1.0078005	$0.0198407	$54,971,279
5	2 - Small Power	Sec. Dist	801,777,853	1.0979	880,275,091	1.0078005	$0.0198407	$15,907,835
6	3B - General Power	Sec. Dist	1,441,312,473	1.0979	1,582,422,692	1.0078005	$0.0198407	$28,596,650
7	3C - General Power (Low Load Factor)	Sec. Dist	184,107,233	1.0979	202,132,063	1.0078005	$0.0198407	$3,652,817
8	4B - Large Power	Pri. Dist	997,857,409	1.0721	1,069,756,277	0.9840713	$0.0193735	$19,332,032
9	5B - Large Service for Customers >=8,000kW	Subtransmission	68,588,213	1.0514	72,110,998	0.9650776	$0.0189996	$1,303,149
10	10 - Irrigation	Sec. Dist	20,509,415	1.0979	22,517,369	1.0078005	$0.0198407	$406,921
11	11B - Wtr/Swg Pumping	Pri. Dist	162,613,829	1.0721	174,330,684	0.9840713	$0.0193735	$3,150,406
12	15B - Universities 115 kV	Transmission	63,683,882	1.0499	66,860,033	0.9637120	$0.0189727	$1,208,257
13	30B - Manuf. (30 MW)	Substation	353,320,791	1.0569	373,421,345	0.9701528	$0.0190995	$6,748,260
14	33B - Large Service for Station Power	Transmission	2,936,542	1.0499	3,082,999	0.9637120	$0.0189727	$55,714
15	35B - Large Power Service >=3,000kW	Substation	199,999,455	1.0569	211,377,500	0.9701528	$0.0190995	$3,819,895
16	36B - Special Service -Renw. Energy Res.	Transmission	36,886,181	1.0499	38,725,832	0.9637120	$0.0189727	$699,831
17	6 - Private Lighting	Sec. Dist	13,478,136	1.0979	14,797,699	1.0078005	$0.0198407	$267,416
18	20 - Streetlighting	Sec. Dist	43,661,504	1.0979	47,936,138	1.0078005	$0.0198407	$866,275
19	Totals		7,161,364,736	1.0894	7,801,634,403	1.0000000	$0.0196871	$140,986,737

PNM EXHIBIT JCA-5
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Projected Energy Sales Test Period - by Group of Customers

A	B	C= D+ E + F	D	E	F	G	H	I	J
Line No.	Consolidated Tariff Class	PNM kWh Total	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)				
1	1A/1B - Residential	3,164,862,106	93,715	0	3,164,768,391				
2	2A/2B - Small Power	915,396,797	3,296,290	0	912,100,507				
3	3B - General Power	1,641,925,784	31,459,294	0	1,610,466,490				
4	3C - General Power (Low Load Factor)	210,125,160	1,260,660	0	208,864,500				
5	4B - Large Power	1,106,704,902	28,373,622	265,070,000	813,261,279				
6	5B - Large Service for Customers >=8,000kW	70,596,567	0	70,596,567	0				
7	10A/10B - Irrigation	23,427,777	0	0	23,427,777				
8	11B - Wtr/Swg Pumping	168,508,457	121,188,068	0	47,320,388				
9	15B - Universities 115 kV	63,683,882	63,683,882	0	0				
10	30B - Manufacturing (30 MW)	363,666,494	0	363,666,494	0				
11	33B - Station Service	3,354,394	0	0	3,354,394				
12	35B - Large Power >=3,000kW	205,855,705	0	205,855,705	0				
13	36B - Special Service -Renw. Energy Res.	37,966,258	0	37,966,258	0				
14	6 - Private Lighting	15,388,500	52,644	0	15,335,856				
15	20 - Streetlighting	49,850,940	163,908	0	49,687,032				
16	Tariff Class Totals	8,041,313,722	249,572,084	943,155,024	6,848,586,614				

Projected Fuel Revenues Method (A)

			Non-Renewable Energy			Renewable Energy			
Line No.	Consolidated Tariff Class	PNM kWh Non-Renewable	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)	Total Of Fuel Related Costs ($)
17	1A/1B - Residential	2,770,631,819	93,715	0	2,770,538,104	0	0	394,230,286	$54,971,279
18	2A/2B - Small Power	801,777,853	3,296,290	0	798,481,563	0	0	113,618,944	$15,907,835
19	3B - General Power	1,441,312,473	31,459,294	0	1,409,853,179	0	0	200,613,311	$28,596,650
20	3C - General Power (Low Load Factor)	184,107,233	1,260,660	0	182,846,573	0	0	26,017,927	$3,652,817
21	4B - Large Power	997,857,409	28,373,622	257,529,202	711,954,584	0	7,540,798	101,306,695	$19,332,032
22	5B - Large Service for Customers >=8,000kW	68,588,213	0	68,588,213	0	0	2,008,354	0	$1,303,149
23	10A/10B - Irrigation	20,509,415	0	0	20,509,415	0	0	2,918,362	$406,921
24	11B - Wtr/Swg Pumping	162,613,829	121,188,068	0	41,425,761	0	0	5,894,627	$3,150,406
25	15B - Universities 115 kV	63,683,882	63,683,882	0	0	0	0	0	$1,208,257
26	30B - Manufacturing (30 MW)	353,320,791	0	353,320,791	0	0	10,345,703	0	$6,748,260
27	33B - Station Service	2,936,542	0	0	2,936,542	0	0	417,852	$55,714
28	35B - Large Power >=3,000kW	199,999,455	0	199,999,455	0	0	5,856,250	0	$3,819,895
29	36B - Special Service -Renw. Energy Res.	36,886,181	0	36,886,181	0	0	1,080,076	0	$699,831
30	6 - Private Lighting	13,478,136	52,644	0	13,425,492	0	0	1,910,364	$267,416
31	20 - Streetlighting	43,661,504	163,908	0	43,497,596	0	0	6,189,436	$866,275
32	Tariff Class Totals	7,161,364,736	249,572,084	916,323,843	5,995,468,810	0	26,831,181	853,117,804	$140,986,737

PNM EXHIBIT JCA-5
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Calculation of Fuel Rates based on Revised Voltage Class Adjustment Factors - Base Period Proof of Revenue

Line No.	Description	Value	Notes
1	Fuel Costs	$ 177,752,491	[A]
2	Consolidated kWh at Meter (Non-Renewable)	7,328,535,651	[B]
3	Average Fuel Rate	$0.0242548	[C] = [A] / [B]

Consolidated Class Base Fuel Allocations

Line No.	Rate Class	Voltage Class	Consolidated kWh at Meter (Non-Renewable) page 4, Col. C. Rows 17-32 [D]	Cumulative Loss Factor [E]	Consolidated kWh at Generator [F] = [D] * [E]	Voltage Class Adjustment Factors [G] = [E] / [E] $_{TOTAL}$	Fuel Rate per kWh [H] = [C] * [G]	Fuel Revenue by Rate Class [I] = [D] * [H]
4	1 - Residential	Sec. Dist	2,806,146,551	1.0986	3,082,812,857	1.0078636	$0.0244456	$68,597,865
5	2 - Small Power	Sec. Dist	838,651,647	1.0986	921,336,799	1.0078636	$0.0244456	$20,501,321
6	3B - General Power	Sec. Dist	1,487,439,493	1.0986	1,634,090,561	1.0078636	$0.0244456	$36,361,313
7	3C - General Power (Low Load Factor)	Sec. Dist	179,232,669	1.0986	196,903,749	1.0078636	$0.0244456	$4,381,446
8	4B - Large Power	Pri. Dist	1,026,273,993	1.0726	1,100,752,158	0.9839911	$0.0238666	$24,493,620
9	5B - Large Service for Customers >=8,000kW	Subtransmission	81,078,785	1.0518	85,277,711	0.9649243	$0.0234041	$1,897,575
10	10 - Irrigation	Sec. Dist	20,233,409	1.0986	22,228,281	1.0078636	$0.0244456	$494,617
11	11B - Wtr/Swg Pumping	Pri. Dist	166,758,535	1.0726	178,860,439	0.9839911	$0.0238666	$3,979,951
12	15B - Universities 115 kV	Transmission	70,433,581	1.0503	73,976,360	0.9635586	$0.0233710	$1,646,101
13	30B - Manuf. (30 MW)	Substation	396,885,744	1.0573	419,638,515	0.9700068	$0.0235274	$9,337,675
14	33B - Large Service for Station Power	Transmission	3,302,102	1.0503	3,468,197	0.9635586	$0.0233710	$77,173
15	35B - Large Power Service >=3,000kW	Substation	194,808,348	1.0573	205,976,373	0.9700068	$0.0235274	$4,583,327
16	36B - Special Service -Renw. Energy Res.	Transmission	0	1.0503	0	0.9635586	$0.0233710	$0
17	6 - Private Lighting	Sec. Dist	13,523,047	1.0986	14,856,324	1.0078636	$0.0244456	$330,579
18	20 - Streetlighting	Sec. Dist	43,767,746	1.0986	48,082,938	1.0078636	$0.0244456	$1,069,928
19	Totals		7,328,535,651	1.0900	7,988,261,263	1.0000000	$0.0242548	$177,752,491

PNM EXHIBIT JCA-5
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Projected Energy Sales Base Period- by Group of Customers

A	B	C= D+ E + F	D	E	F	G	H	I	J
Line No.	Consolidated Tariff Class	PNM kWh Total	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)				
1	1A/1B - Residential	3,205,430,362	93,715	0	3,205,336,647				
2	2A/2B - Small Power	957,517,502	3,296,290	0	954,221,212				
3	3B - General Power	1,694,616,391	31,459,294	0	1,663,157,097				
4	3C - General Power (Low Load Factor)	204,556,976	1,260,660	0	203,296,316				
5	4B - Large Power	1,139,164,989	28,373,622	265,070,000	845,721,367				
6	5B - Large Service for Customers >=8,000kW	83,452,880	0	83,452,880	0				
7	10A/10B - Irrigation	23,112,497	0	0	23,112,497				
8	11B - Wtr/Swg Pumping	173,242,928	121,188,068	0	52,054,860				
9	15B - Universities 115 kV	70,433,581	70,433,581	0	0				
10	30B - Manufacturing (30 MW)	408,507,087	0	408,507,087	0				
11	33B - Station Service	3,771,971	0	0	3,771,971				
12	35B - Large Power >=3,000kW	200,512,596	0	200,512,596	0				
13	36B - Special Service -Renw. Energy Res.	0	0	0	0				
14	6 - Private Lighting	15,439,801	52,644	0	15,387,157				
15	20 - Streetlighting	49,972,300	163,908	0	49,808,392				
16	Tariff Class Totals	8,229,731,860	256,321,783	957,542,563	7,015,867,515				

Projected Fuel Revenues Method (A)

			Non-Renewable Energy			Renewable Energy			
Line No.	Consolidated Tariff Class	PNM kWh Non-Renewable	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)	Exempt Customers (kWh)	Capped Customers (kWh)	Non-Capped/Non-Exempt (kWh)	Total Of Fuel Related Costs ($)
17	1A/1B - Residential	2,806,146,551	93,715	0	2,806,052,836	0	0	399,283,811	$68,594,841
18	2A/2B - Small Power	838,651,647	3,296,290	0	835,355,357	0	0	118,865,855	$20,500,418
19	3B - General Power	1,487,439,493	31,459,294	0	1,455,980,199	0	0	207,176,898	$36,359,710
20	3C - General Power (Low Load Factor)	179,232,669	1,260,660	0	177,972,009	0	0	25,324,306	$4,381,252
21	4B - Large Power	1,026,273,993	28,373,622	257,529,202	740,371,169	0	7,540,798	105,350,198	$24,496,071
22	5B - Large Service for Customers >=8,000kW	81,078,785	0	81,078,785	0	0	2,374,095	0	$1,897,912
23	10A/10B - Irrigation	20,233,409	0	0	20,233,409	0	0	2,879,088	$494,596
24	11B - Wtr/Swg Pumping	166,758,535	121,188,068	0	45,570,467	0	0	6,484,393	$3,980,349
25	15B - Universities 115 kV	70,433,581	70,433,581	0	0	0	0	0	$1,646,393
26	30B - Manufacturing (30 MW)	396,885,744	0	396,885,744	0	0	11,621,343	0	$9,339,254
27	33B - Station Service	3,302,102	0	0	3,302,102	0	0	469,869	$77,187
28	35B - Large Power >=3,000kW	194,808,348	0	194,808,348	0	0	5,704,248	0	$4,584,102
29	36B - Special Service -Renw. Energy Res.	0	0	0	0	0	0	0	$0
30	6 - Private Lighting	13,523,047	52,644	0	13,470,403	0	0	1,916,754	$330,564
31	20 - Streetlighting	43,767,746	163,908	0	43,603,838	0	0	6,204,554	$1,069,881
32	Tariff Class Totals	7,328,535,651	256,321,783	930,302,080	6,141,911,788	0	27,240,483	873,955,726	$177,752,530

Comparison of Current and Proposed Non-Volumetric Charges by Rate Schedule

PNM Exhibit JCA-6

Is contained in the following 1 page

Comparison of Non-Volumetric Retail Rates: Current vs. Proposed

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	**Current Non-Volumetric Rates-SUMMARY**								
2	**Rate Class**	**Class**	**Schedule**	**Customer Charge**	**Customer Charge-Summer**	**Customer Charge-Non Summer**	**Meter Charge**	**Demand Rate Summer**	**Demand Rate Non-Summer**
3				***$/month***	***$/month***	***$/month***	***$/month***	***$/kW***	***$/kW***
4	*Rate Class 1*	*Residential*							
5		*Residential*	1A	$ 7.00					
6		*Residential*	1B	$ 20.81			$ 5.29		
7	*Rate Class 2*	*Small Power*							
8		*Small Power*	2A	$ 15.53					
9		*Small Power*	2B	$ 7.43			$ 8.10		
10	*Rate Class 3*	*General Power*							
11		*General Power High Load Factor*	3B Primary		$ 80.64	$ 80.64		$ 24.83	$ 18.45
12		*General Power High Load Factor*	3B Secondary		$ 80.64	$ 80.64		$ 25.16	$ 18.78
13		*General Power Low Load Factor*	3C Primary		$ 80.64	$ 80.64		$ 7.65	$ 5.63
14		*General Power Low Load Factor*	3C Secondary		$ 80.64	$ 80.64		$ 7.98	$ 5.96
15	*Rate Class 4*	*Large Power*	4B Primary		$ 577.08	$ 577.08		$ 23.36	$ 16.25
16		*Large Power*	4B Secondary		$ 577.08	$ 577.08		$ 25.25	$ 18.14
17	*Rate Class 5*	*Large Service for Customers >=8,000kW*	5B		$ 3,026.64	$ 3,026.64		$ 18.74	$ 11.38
18	*Rate Class 10*	*Irrigation*							
19		*Irrigation*	10A	$ 9.93					
20		*Irrigation*	10B	$ 7.39			$ 2.54		
21	*Rate Class 11*	*Water & Sewage*	11B	$ 442.44					
22	*Rate Class 15*	*Universities*	15B		$ 3,609.00	$ 3,609.00		$ 20.31	$ 12.29
23	*Rate Class 30*	*Large Service for Manufacturing*	30B		$ 23,874.89	$ 23,874.89		$ 28.79	$ 20.35
24	*Rate Class 33*	*Station Power*	33B		$ 438.38	$ 438.38		$ 5.25	$ 3.62
	Rate Class 35	*Large Power Service >=3,000kW*	35B		$ 2,687.80	$ 2,687.80		$ 24.07	$ 15.49
25	*Rate Class 36*	*Special Service -Renw. Energy Res.*	36B		N/A	N/A		N/A	N/A
26									
27	**Proposed Non-Volumetric Rates-SUMMARY**								
28	**Rate Class**	**Class**	**Schedule**	**Customer Charge**	**Customer Charge-Summer**	**Customer Charge-Non Summer**	**Meter Charge**	**Demand Rate Summer**	**Demand Rate Non-Summer**
29	*Rate Class 1*	*Residential*		***$/month***	***$/month***	***$/month***	***$/month***	***$/kW***	***$/kW***
30		*Residential*	1A	$ 13.77					
31		*Residential*	1B	$ 20.81			$ 5.29		
32	*Rate Class 2*	*Small Power*							
33		*Small Power*	2A	$ 18.33					
34		*Small Power*	2B	$ 10.08			$ 8.25		
35	*Rate Class 3*	*General Power*							
36		*General Power High Load Factor*	3B Primary		$ 83.80	$ 83.80		$ 29.35	$ 22.90
37		*General Power High Load Factor*	3B Secondary		$ 83.80	$ 83.80		$ 29.68	$ 23.23
38		*General Power Low Load Factor*	3C Primary		$ 69.59	$ 69.59		$ 10.56	$ 8.06
39		*General Power Low Load Factor*	3C Secondary		$ 69.59	$ 69.59		$ 10.89	$ 8.39
40	*Rate Class 4*	*Large Power*	4B Primary		$ 592.64	$ 592.64		$ 29.79	$ 21.09
41		*Large Power*	4B Secondary		$ 592.64	$ 592.64		$ 31.23	$ 22.53
42	*Rate Class 5*	*Large Service for Customers >=8,000kW*	5B		$ 2,498.62	$ 2,498.62		$ 23.60	$ 14.98
43	*Rate Class 10*	*Irrigation*							
44		*Irrigation*	10A	$ 18.33					
45		*Irrigation*	10B	$ 12.57			$ 5.76		
46	*Rate Class 11*	*Water & Sewage*	11B	$ 327.02					
47	*Rate Class 15*	*Universities*	15B		$ 4,431.00	$ 4,431.00		$ 20.01	$ 13.56
48	*Rate Class 30*	*Large Service for Manufacturing*	30B		$ 22,462.95	$ 22,462.95		$ 33.84	$ 22.92
49	*Rate Class 33*	*Station Power*	33B		$ 455.23	$ 455.23		$ 7.72	$ 4.88
	Rate Class 35	*Large Power Service >=3,000kW*	35B		$ 3,331.01	$ 3,331.01		$ 27.02	$ 18.23
50	*Rate Class 36*	*Special Service -Renw. Energy Res.*	36B		$ 2,553.13	$ 2,553.13		$ 4.41	$ 4.41
51									

Derivation of the Factors Used for the Assignment of Demand Production Costs to Seasons

PNM Exhibit JCA-7

Is contained in the following 1 page

Derivation of the Factors used for the Assigment of Demand Production Costs to Seasons

Peak Load by Period (MW)

	(Base)		*(Intermediate)*	*(Peak)*	
	(A)	(B)	(C)	(D)	(E)
Year	**NS-Off**	**S-Off**	**NS-On**	**S-On**	**Grand Total**
2007	1682	1837	1755	1933	1933
2008	1605	1795	1643	1901	1901
2009	1580	1735	1674	1866	1866
2010	1605	1817	1698	1973	1973
2011	1663	1831	1815	1938	1938
2012	1712	1877	1775	1948	1948
2013	1633	1890	1780	2008	2008
2014	1614	1823	1737	1878	1878
2015	1539	1777	1678	1889	1889

Minimum Load by Period (MW)

	(Base)		*(Intermediate)*	*(Peak)*	
	(F)	(G)	(H)	(I)	(J)
Year	**NS-Off**	**S-Off**	**NS-On**	**S-On**	**Grand Total**
2007	813	851	925	1129	813
2008	709	865	976	1098	709
2009	752	797	887	1053	752
2010	769	847	976	930	769
2011	795	876	953	1131	795
2012	796	875	902	1121	796
2013	762	847	927	1070	762
2014	741	810	878	1002	741
2015	743	797	849	1039	743

Number of Hours by Period (Hours)

	(Base)		*(Intermediate)*	*(Peak)*	
	(K)	(L)	(M)	(N)	(O)
Year	**NS-Off**	**S-Off**	**NS-On**	**S-On**	**Grand Total**
2007	4212	1416	2340	792	8760
2008	4212	1428	2364	780	8784
2009	4212	1416	2340	792	8760
2010	4212	1416	2340	792	8760
2011	4224	1416	2328	792	8760
2012	4236	1416	2340	792	8784
2013	4200	1428	2352	780	8760
2014	4200	1428	2352	780	8760
2015	4212	1415	2340	792	8759

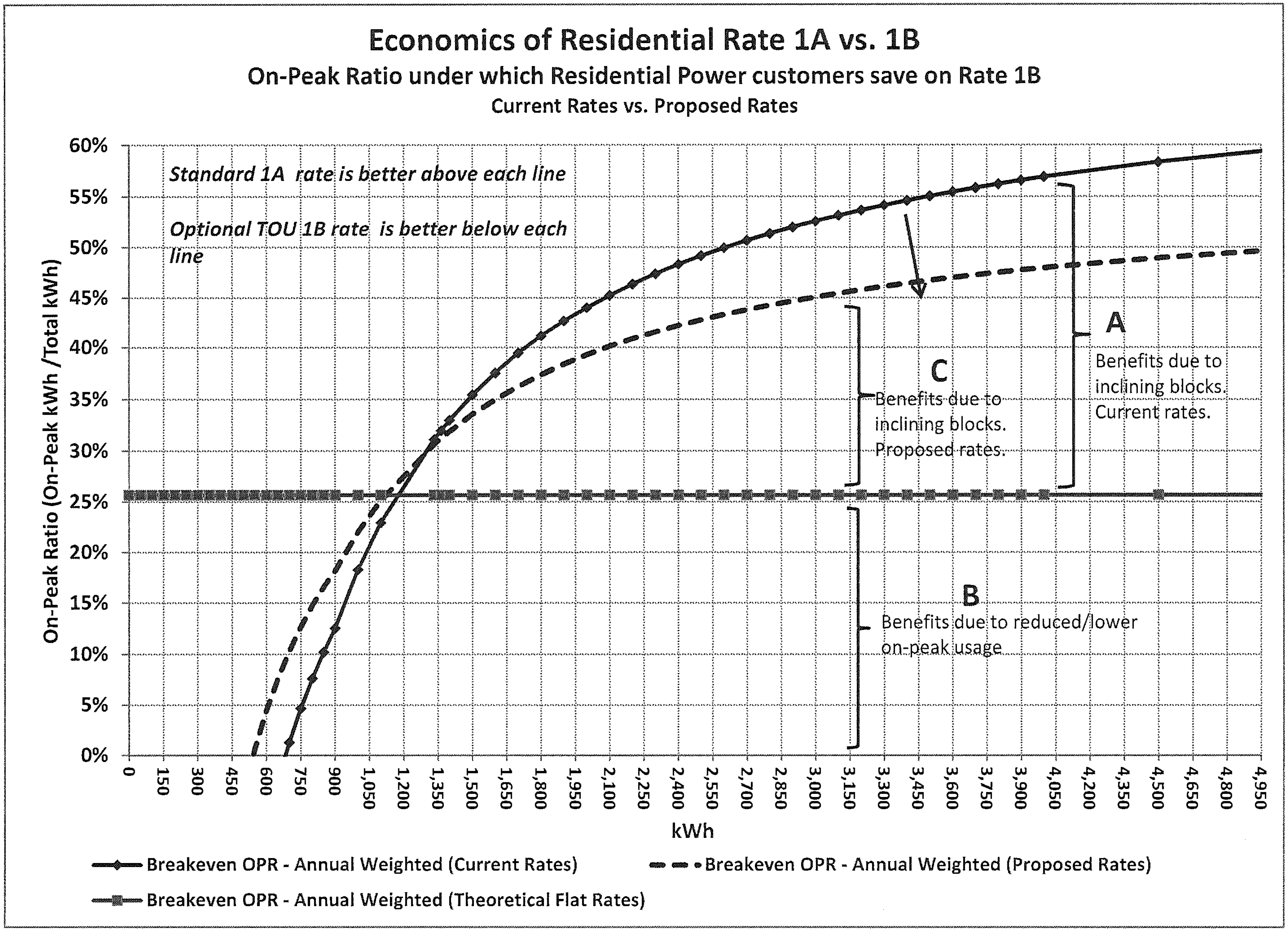
	Off	*On*	
	(P)	*(Q)*	*(R)*
% of Hours	*=[(K)+(L)]/(O)*	*=(M)/[(M)+(N)]*	*=(N)/[(M)+(N)]*
		NS	***S***
2007	64.25%	74.71%	25.29%
2008	64.21%	75.19%	24.81%
2009	64.25%	74.71%	25.29%
2010	64.25%	74.71%	25.29%
2011	64.38%	74.62%	25.38%
2012	64.34%	74.71%	25.29%
2013	64.25%	75.10%	24.90%
2014	64.25%	75.10%	24.90%
2015	64.24%	74.71%	25.29%

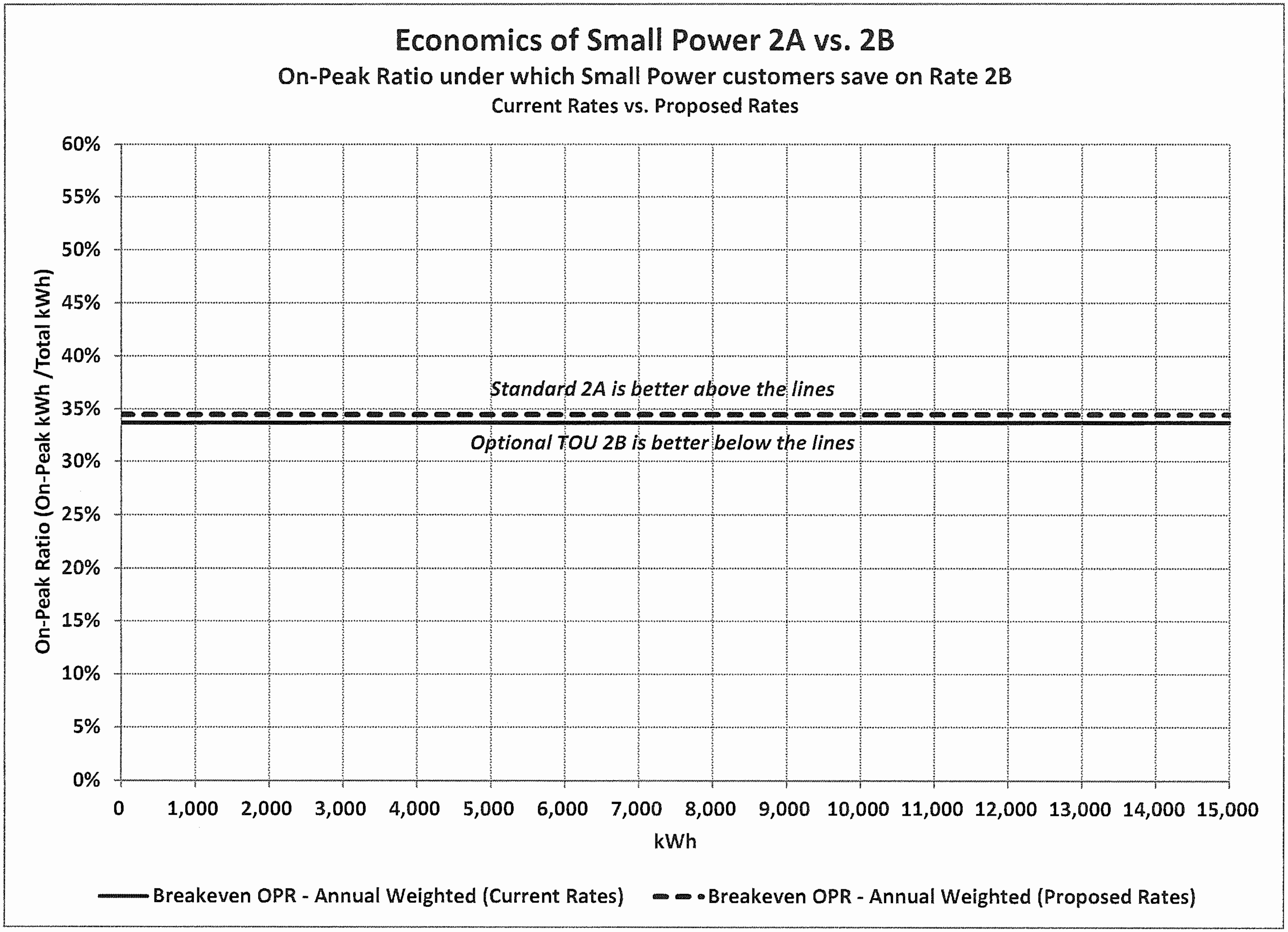
					Ratios		
	Base (Off Peak)	**Non-Summer Peak**	**Summer Peak**		**Non-Summer Peak Share**	**Summer Peak Share**	
	(S)	**(T)**	**(U)**	**(V)**	**(W)**	**(X)**	
	=Min [(F),(G)]/(E)	=[(C)-(F)/(E)]*(Q)	=[{(D)-(C)}/(D)] + [{(C)-(F)}/(D)]*(R)	=(S)+(T)+(U)	=(T)/[(T)+(U)]	=(U)/[(T)+(U)]	
2007	42.06%	36.41%	21.53%	100.00%	62.84%	37.16%	100.00%
2008	37.30%	36.94%	25.76%	100.00%	58.92%	41.08%	100.00%
2009	40.30%	36.92%	22.78%	100.00%	61.84%	38.16%	100.00%
2010	38.98%	35.18%	25.84%	100.00%	57.65%	42.35%	100.00%
2011	41.02%	39.27%	19.71%	100.00%	66.59%	33.41%	100.00%
2012	40.86%	37.55%	21.59%	100.00%	63.49%	36.51%	100.00%
2013	37.95%	38.07%	23.98%	100.00%	61.35%	38.65%	100.00%
2014	39.46%	39.83%	20.72%	100.00%	65.78%	34.22%	100.00%
2015	39.33%	36.98%	23.69%	100.00%	60.96%	39.04%	100.00%
				Average	**62.157%**	**37.843%**	**100.00%**

Economics of the Residential Rate 1A and Residential TOU 1B

PNM Exhibit JCA-8

Is contained in the following 2 pages


Economics of Residential Rate 1A vs. 1B
On-Peak Ratio under which Residential Power customers save on Rate 1B
Current Rates vs. Proposed Rates
Standard 1A rate is better above each line
Optional TOU 1B rate is better below each line
A
Benefits due to inclining blocks. Current rates.
C
Benefits due to inclining blocks. Proposed rates.
B
Benefits due to reduced/lower on-peak usage
On-Peak Ratio (On-Peak kWh /Total kWh)
60%
55%
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
0
150
300
450
600
750
900
1,050
1,200
1,350
1,500
1,650
1,800
1,950
2,100
2,250
2,400
2,550
2,700
2,850
3,000
3,150
3,300
3,450
3,600
3,750
3,900
4,050
4,200
4,350
4,500
4,650
4,800
4,950
kWh
Breakeven OPR - Annual Weighted (Current Rates)
Breakeven OPR - Annual Weighted (Proposed Rates)
Breakeven OPR - Annual Weighted (Theoretical Flat Rates)


Economics of Small Power 2A vs. 2B
On-Peak Ratio under which Small Power customers save on Rate 2B
Current Rates vs. Proposed Rates
On-Peak Ratio (On-Peak kWh /Total kWh)
60%
55%
50%
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
Standard 2A is better above the lines
Optional TOU 2B is better below the lines
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
kWh
Breakeven OPR - Annual Weighted (Current Rates)
Breakeven OPR - Annual Weighted (Proposed Rates)

Summary of Electric Utilities with Residential Inclining Block Rates

PNM Exhibit JCA-9

Is contained in the following 1 page

Table II-2
Largest Utilities Nationwide With Inclining Block Rates

Company	State	Monthly Customer Charge	Number of Tiers	Highest-to-Lowest Tier Ratio
Portland General Electric Company	Oregon	$10.00	2	1.1
Jersey Central Power & Light Company	New Jersey	$2.20	1 - 2	1.1
South Carolina Electric & Gas Company	South Carolina	$10.00	2	1.1
Public Service Electric & Gas Company	New Jersey	$2.27	2	1.1
Consolidated Edison Company of New York*	New York	$15.76	1 - 2	1.1
DTE Electric Company	Michigan	$6.00	2	1.1
Public Service Company of Oklahoma**	Oklahoma	$16.16	2 - 3	1.1
Dominion Virginia Power	Virginia	$7.00	2	1.1
Puget Sound Energy	Washington	$7.49	2	1.2
OG&E Electric Services*	Oklahoma	$13.00	1 - 2	1.2
Duke Energy Florida	Florida	$8.76	2	1.2
Tampa Electric Company	Florida	$15.00	2	1.2
Entergy Arkansas, Inc.	Arkansas	$6.96	2	1.2
Florida Power & Light Company	Florida	$7.57	2	1.2
Consumers Energy*	Michigan	$7.00	1 - 2	1.3
Georgia Power Company	Georgia	$10.00	3	1.4
Idaho Power Company	Idaho	$5.00	3	1.4
PacifiCorp*	Utah	$5.00	2 - 3	1.6
Arizona Public Service Company*	Arizona	$8.67	1 - 4	1.8
Public Service Company of Colorado*	Colorado	$6.75	1 - 2	1.8
Pacific Gas & Electric Company	California	$0.00	4	2.1
Southern California Edison	California	$0.94	4	2.1
San Diego Gas & Electric Company	California	$0.00	4	2.4
* IBR during summer.				
**Limited usage tariff available with $9.98 monthly fixed charge.				

The figure below demonstrates how the California IOUs are outliers among the nation's largest electric utilities, and how SCE's Proposal would bring California's IOUs more in line with their peers.

Summary of Revenue Impacts of PNM's Proposed Rates

PNM Exhibit JCA-10

Is contained in the following 1 page

Estimated Revenue Impact by Rate Class

Comparison of Current Rates to Proposed Rates

(Includes Applicable FPPCAC and other Rider Charges for Illustration Purposes only)

Total Revenues at Existing Rates ($)

A	B	C	D= B + C	E	F	G= D + E + F
Rate Class	Forecasted Non-Fuel Base Revenues @ Existing Rates	Forecasted FPPCAC @ Existing Rates(1)	Total Base Rates+ FPPCAC Revenue	Projected Renewable Energy Rider No. 36 (2)	Projected Energy Efficiency Rider No. 16 (3)	Total Revenue
1A/1B - Residential	$332,143,835	$54,971,279	$387,115,114	$22,253,072	$13,130,238	$422,498,423
2A/2B - Small Power	$97,931,024	$15,907,835	$113,838,859	$6,463,336	$3,858,620	$124,160,815
3B - General Power	$122,995,870	$28,596,650	$151,592,521	$11,816,448	$5,241,244	$168,650,213
3C - General Power (Low Load Factor)	$22,768,915	$3,652,817	$26,421,732	$1,379,912	$891,721	$28,693,365
4B - Large Power	$66,723,164	$19,332,032	$86,055,197	$6,567,538	$2,970,818	$95,593,553
5B - Large Service for Customers >=8,000kW	$3,951,210	$1,303,149	$5,254,359	$151,401	$161,214	$5,566,974
10A/10B - Irrigation	$1,798,513	$406,921	$2,205,434	$183,510	$0	$2,388,944
11B - Wtr/Swg Pumping	$8,363,040	$3,150,406	$11,513,446	$406,882	$366,323	$12,286,650
15B - Universities 115 kV	$3,794,036	$1,208,257	$5,002,293	$0	$85,377	$5,087,670
30B - Manufacturing (30 MW)	$14,181,934	$6,748,260	$20,930,194	$111,711	$118,649	$21,160,554
33B - Station Service	$173,642	$55,714	$229,356	$23,124	$0	$252,480
35B - Large Power >=3,000kW	$5,835,654	$3,819,895	$9,655,549	$170,215	$295,921	$10,121,685
36B - Special Service -Renw. Energy Res.(4)	$2,152,113	$699,831	$2,851,944	$61,447	$0	$2,913,391
6 - Private Lighting	$2,668,780	$267,416	$2,936,196	$110,467	$0	$3,046,663
20 - Streetlighting	$6,905,774	$866,275	$7,772,048	$347,086	$0	$8,119,135
Customer Rate Class Totals	$692,387,504	$140,986,737	$833,374,241	$50,046,148	$27,120,124	$910,540,513

Total Revenues at Proposed Rates ($)

H	I	J = (I/B-1)	K	L = I + K	M = (L/D-1)	N	O	P = L + N + O	Q = (P/G-1)
Rate Class	Forecasted Non-Fuel Base Revenues @ Proposed Rates	Increase (%)	Forecasted FPPCAC @ Proposed Rates (1)	Total Base Rates+ FPPCAC Revenue	Increase (%)	Projected Renewable Energy Rider No. 36 (2)	Projected Energy Efficiency Rider No. 16 (3)	Total Revenue	Increase (%)
1A/1B - Residential	$384,499,668	15.76%	$54,971,279	$439,470,946	13.52%	$22,253,072	$14,809,290	$476,533,308	12.79%
2A/2B - Small Power	$110,305,765	12.64%	$15,907,835	$126,213,600	10.87%	$6,463,336	$4,255,467	$136,932,402	10.29%
3B - General Power	$138,537,850	12.64%	$28,596,650	$167,134,501	10.25%	$11,816,448	$5,739,655	$184,690,603	9.51%
3C - General Power (Low Load Factor)	$25,646,037	12.64%	$3,652,817	$29,298,853	10.89%	$1,379,912	$983,988	$31,662,753	10.35%
4B - Large Power	$76,078,783	14.02%	$19,332,032	$95,410,815	10.87%	$6,567,538	$3,270,843	$105,249,196	10.10%
5B - Large Service for Customers >=8,000kW	$4,450,492	12.64%	$1,303,149	$5,753,641	9.50%	$151,401	$162,246	$6,067,289	8.99%
10A/10B - Irrigation	$2,082,013	15.76%	$406,921	$2,488,934	12.85%	$183,510	$0	$2,672,444	11.87%
11B - Wtr/Swg Pumping	$9,681,306	15.76%	$3,150,406	$12,831,712	11.45%	$406,882	$408,599	$13,647,192	11.07%
15B - Universities 115 kV	$4,273,458	12.64%	$1,208,257	$5,481,714	9.58%	$0	$86,369	$5,568,083	9.44%
30B - Manufacturing (30 MW)	$15,973,989	12.64%	$6,748,260	$22,722,248	8.56%	$111,711	$122,355	$22,956,315	8.49%
33B - Station Service	$195,584	12.64%	$55,714	$251,298	9.57%	$23,124	$0	$274,422	8.69%
35B - Large Power >=3,000kW	$6,755,528	15.76%	$3,819,895	$10,575,423	9.53%	$170,215	$325,420	$11,071,058	9.38%
36B - Special Service -Renw. Energy Res.(4)	$2,372,497	10.24%	$699,831	$3,072,328	7.73%	$61,447	$0	$3,133,775	7.56%
6 - Private Lighting	$3,006,012	12.64%	$267,416	$3,273,428	11.49%	$110,467	$0	$3,383,895	11.07%
20 - Streetlighting	$7,778,400	12.64%	$866,275	$8,644,674	11.23%	$347,086	$0	$8,991,761	10.75%
Customer Rate Class Totals	$791,637,379	14.33%	$140,986,737	$932,624,116	11.91%	$50,046,148	$30,164,231	$1,012,834,494	11.23%
L35-L17	$99,249,875		$0	$99,249,875		$0	$3,044,107	$102,293,982	

Notes:

(1) As projected for the Test Period. For illustration purposes onl\
(2) Revenue projections as filed in Case No. 16-00148-UT. Includes 2% of revenues from Rate 36B as projected for Test Period
(4) Revenue projections for Program Costs calculated as 3% of revenues plus Profit Incentive from Case No. 16-00096-U1
(4) Includes Contribution to Production Revenues. See PNM Exhibit JCA-3

PNM EXHIBIT JCA-10
Page 1 of 1

Derivation of Rider No. 48, Lost Contribution to Fixed Costs, and the Proposed Rider No. 48

PNM Exhibit JCA-11

Is contained in the following 5 pages

Derivation Authorized Fixed Cost Recovery Amount - LCFC Rider No. 48

Line No.	A	B	C	D	E	F	G	H	I
				Residential (1A/1B)			Small Power (2A/2B)		
	Description	Reference		Residential			Small Power		
	Test Period Units								
1	Annual Number of Customers	PNM Exhibit SC-5	Cust			5,615,569			633,896
2	Annual Energy Sales	PNM Exhibit SC-5	Energy Sales			3,164,862,106			915,396,797
3				Revenue - $	Unit Costs/ Customer $/Cust	Unit Costs/ kWh $/kWh	Revenue - $	Unit Costs/ Customer $/Cust	Unit Costs/ kWh $/kWh
4	**Revenue Requirements by Cost Component**								
5	Customer Revenue Requirements (Fixed)	PNM Exhibit JCA-4, pages 1&2, line 1, Column (D)	$	$ 77,334,778	$ 13.77	$ 0.024435	$ 11,621,477	$ 18.33	$ 0.012696
6	Demand Revenue Requirements (Fixed)	PNM Exhibit JCA-4, pages 1&2, line 18, Column (D)	$	$ 287,759,223	$ 51.24	$ 0.090923	$ 92,265,897	$ 145.55	$ 0.100793
7	***Total Fixed Cost Requirements***		*L5+L6*	*$ 365,094,001*	*$ 65.01*	*$ 0.115359*	*$ 103,887,374*	*$ 163.89*	*$ 0.113489*
8	Energy (Non-Fuel) Revenue Requirements (Variable)	PNM Exhibit JCA-4, pages 1&2, line 36, Column (D)	$	$ 19,405,667	$ 3.46	$ 0.006132	$ 6,418,391	$ 10.13	$ 0.007012
9									
10	**Total Variable Cost Requirements**		L8+L9	$ 19,405,667	$ 3.46	$ 0.006132	$ 6,418,391	$ 10.13	$ 0.007012
11	***Total Non-Fuel Revenue Requirements***		L7+L10	*$ 384,499,668*	*$ 68.47*	*$ 0.121490*	*$ 110,305,765*	*$ 174.01*	*$ 0.120500*
12									
13	**Pricing by Revenue Component**								
14	Customer Charge Revenues	PNM Exhibit JCA-4, pages 1&2, Line 1, Column (M)	$	$ 77,344,290	$ 13.77	$ 0.024438	$ 11,619,312	$ 18.33	$ 0.012693
15	Demand Charge Revenues	PNM Exhibit JCA-4, pages 1 & 2, Line 18, Column (M)		$ -			$ -		
16	***Total Fixed Cost Revenues***		*L14+L15*	*$ 77,344,290*	*$ 13.77*	*$ 0.024438*	*$ 11,619,312*	*$ 18.33*	*$ 0.012693*
17									
18	**Total Revenues**		L16	$ 77,344,290	$ 13.77	$ 0.024438	$ 11,619,312	$ 18.33	$ 0.012693
19									
20	***Authorized Fixed Cost Recovery Amount (Fixed Costs in Volumetric Rates)***		*L7-L16*	*$ 287,749,710*	*$ 51.24*	*$ 0.0909201*	*$ 92,268,062*	*$ 145.56*	*$ 0.1007957*

Rate per kWh	*$ 0.0909201*	Rate per kWh	*$ 0.1007957*

PUBLIC SERVICE COMPANY OF NEW MEXICO

ORIGINAL RIDER NO. 48

LOST CONTRIBUTION TO FIXED COSTS
APPLICABLE TO RETAIL RATE SCHEDULES 1A, 1B, 2A AND 2B

DESCRIPTION: Pursuant to the New Mexico Public Regulation Commission's ("NMPRC") Final Order in NMPRC Case No. 16-00276-UT, Public Service Company of New Mexico ("Company") established Original Rider No. 48 – Lost Contribution to Fixed Cost Rider ("LCFC Rider") to provide for the recovery of the fixed costs per customer authorized for recovery in the Company's general rate cases multiplied by the Company's Projected Energy Efficiency ("EE") Savings (as defined below), to be subsequently trued up with Measured and Verified EE Savings (as defined below). Both the Projected EE Savings and the Measured and Verified EE Savings shall be subject to a four-year cap, such that the LCFC Rider shall collect only four years of EE savings for each Company energy efficiency and load management program or measure. The Projected EE Savings and the Measured and Verified EE Savings collected through the LCFC Rider shall reset with each general rate case.

APPLICABILITY: This LCFC Rider shall be applicable to the electric energy delivered to retail customers receiving service under Schedule 1A – Residential Service ("Schedule 1A"); Schedule 1B – Residential Service Time of Use ("TOU") ("Schedule 1B"); Schedule 2A – Small Power Service ("Schedule 2A"); and Schedule 2B – Small Power Service TOU ("Schedule 2B").

APPLICATION: The LCFC Rider Rate, as defined below, shall be added to each Schedule 1A, 1B, 2A and 2B customer bill.

TERRITORY: All territory served by the Company in New Mexico.

RATES, TERMS AND PROCEDURES:

I. Purpose.

This LCFC Rider establishes detailed procedures that will permit the Company to recover the fixed costs per customer authorized for recovery by the NMPRC multiplied by the Projected EE Savings. This amount is to be trued up by Measured and Verified EE Savings.

II. Definitions

The following definitions shall apply to this Rider:

1. Actual Fixed Cost Amount Collected: The Actual Fixed Cost Amount Collected shall be the billed energy sales to customers served pursuant to Schedules 1A, 1B, 2A and 2B multiplied by their applicable LCFC Rider Rate.

2. Adjustment Period for Annual Reset: The Adjustment Period for Annual Reset shall mean the twelve (12) months from the first billing cycle in January through the last billing cycle in December wherein the Company recovers amounts reflected by the LCFC Rider Rate.

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Gerard T. Ortiz
Vice President, PNM Regulatory Affairs
GCG#522675

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3. Adjustment Period for Reconciliation Reset: The Adjustment Period for Reconciliation Reset shall mean the period from the first billing cycle in the month after the effective date of the Reconciliation Reset through the last billing cycle in December wherein the Company recovers amounts reflected by the LCFC Rider Rate.

4. Annual Reset: The Annual Reset shall be the filing that derives Lost Fixed Cost Amount and resets the Individual Factors. The filing with the NMPRC shall be made on an annual basis in an energy efficiency proceeding or as otherwise ordered by the Commission.

5. Authorized Fixed Cost Recovery Factor: The Authorized Fixed Cost Recovery Factor shall be the amount of fixed costs per kWh embedded in the volumetric rate for each applicable rate class as set by the NMPRC.

6. Carrying Charge: The Carrying Charge shall be the applicable Customer Deposit Interest Rate as set by the NMPRC.

7. Individual Factors: The Individual Factors shall be the $ per kWh charges or credits applied to Residential or Small Power customer billed sales the during Annual Reset and the Reconciliation Reset. The Individual Factor is calculated separately for each rate class.

8. LCFC Deferral Account: The LCFC Deferral Account shall include (1) the difference between the Lost Fixed Cost Verified Amount and the Actual Fixed Cost Amount Collected; and (2) Carrying Charges applied to the balance.

9. LCFC Rider Rate: The LCFC Rider Rate shall be the sum of the Individual Factors calculated during Annual Reset and the Reconciliation Reset.

10. Lost Fixed Cost Amount: The Lost Fixed Cost Amount shall be the Authorized Fixed Cost Recovery Factor multiplied by Projected EE Savings.

11. Lost Fixed Cost Verified Amount: The Lost Fixed Cost Verified Amount shall be the Authorized Fixed Cost Recovery Factor multiplied by Measured and Verified EE Savings.

12. Measured and Verified EE Savings: The Measured and Verified EE Savings shall be the annual energy savings set forth in the measurement and verification report for annual energy savings filed annually by the Company pursuant to Title 17, Chapter 7, Part 2, Section 14 (17.7.2.14) of the New Mexico Administrative Code. Measured and Verified EE Savings shall be subject to a four-year cap, such that the LCFC Rider shall collect only four years of Measured and Verified EE Savings for each Company

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energy efficiency and load management program or measure. The Measured and Verified EE Savings collected through the LCFC Rider shall reset with each general rate case.

13. Projected EE Savings: The Projected EE Savings shall be the estimated annual energy savings filed annually by the Company pursuant to Title 17, Chapter 7, Part 2, Section 14 (17.7.2.14) of the New Mexico Administrative Code. Projected EE Savings shall be subject to a four-year cap, such that the LCFC Rider shall collect only four years of Projected EE Savings for each energy efficiency and load management program or measure. The Projected EE Savings collected through the LCFC Rider shall reset with each general rate case.

14. Reconciliation Reset: The Reconciliation Reset shall be the filing that derives the LCFC Deferral Account and resets the Individual Factors. The filing with NMPRC will be made after the Company has filed the Measured and Verified EE Savings.

15. Residential or Residential Service: Residential or Residential Service shall mean service to customers served pursuant to Rate Schedules 1A or 1B.

16. Small Power or Small Power Service: Small Power or Small Power Service shall mean service to customers served pursuant to Rate Schedules 2A or 2B.

17. Total Fixed Cost Requirement: The Total Fixed Cost Requirement shall be the class-specific revenue requirement approved in the Company's last rate case associated with customer-related and demand-related activities that do not vary as a result of energy sales (kWh). Fixed costs consist of all production, transmission and distribution demand allocated costs and customer-allocated costs, where applicable.

III. Calculation and Administration of the LCFC Rider

The LCFC Rider reconciles the differences between the Lost Fixed Cost Verified Amount and the Actual Fixed Cost Amount Collected for each customer class, called the LCFC Deferral Account. The LCFC Deferral Account is tracked separately for Residential and Small Power. The calculated factors used for the LCFC Rider are described below.

1. Authorized Fixed Cost Recovery Factor Calculation. The Authorized Fixed Cost Recovery Calculation represents the difference between the Total Fixed Cost Requirement and the amount of revenue resulting from the customer charges approved by the NMPRC for the Residential and Small Power rate classes on a per kWh energy basis using the total energy sales in the test period for the applicable rate case, as follows:

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APPLICABLE TO RETAIL RATE SCHEDULES 1A, 1B, 2A AND 2B

Residential Authorized Fixed Cost Recovery Factor (Schedules 1A and 1B)
Effective Date: Upon Approval Factor: $0.0909201 per kWh

Small Power Authorized Fixed Cost Recovery Factor (Schedules 2A and 2B)
Effective Date: Upon Approval Factor: $0.1007957 per kWh

2. Individual Factor and LCFC Rider Rate Calculation: The Individual Factor for the Residential and Small Power rate classes is re-calculated twice per year for the Annual Reset and Reconciliation Reset.
   a. The Individual Factor is calculated for the Annual Reset by dividing the Lost Fixed Cost Amount by the forecast sales for the Adjustment Period for Annual Reset for each applicable rate class.
   b. The Individual Factor is calculated for the Reconciliation Reset by dividing the LCFC Deferral Account by the forecast sales for the Adjustment Period for Reconciliation Reset for each applicable rate class.
   c. The sum of the Individual Factors represents the LCFC Rider Rate for each applicable rate schedule and are set forth as:

Schedule 1A – Residential Service	$0.000000 per kWh
Schedule 1B – Residential Service TOU Rate	$0.000000 per kWh
Schedule 2A – Small Power Service	$0.000000 per kWh
Schedule 2B – Small Power Service TOU Rate	$0.000000 per kWh

3. Special Tax and Assessment Adjustment: Billings under this LCFC Rider may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

4. Duration of the Rider: This LCFC Rider duration shall be in effect until replaced or canceled by the NMPRC.

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Vice President, PNM Regulatory Affairs

GCG#522675

Rate Design for Rate 20 – Integrated System Streetlighting and Floodlighting Service

PNM Exhibit JCA-12

Is contained in the following 9 pages

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Rate 20 & Rider 35 – Rate Design Methodology

In order to develop a cost-based allocator for Company-owned light and pole facilities, PNM first looked at the replacement costs for each light and pole that PNM is proposing in this case. However, in order to address other factors like limiting the impact of total rate increases to Rate 20 Customers, PNM made several adjustments to the installed costs to develop light and pole cost allocation factors (See Table A).

Table A: Deemed Replacement Costs & Revenue Requirements for PNM-Owned Lights & Poles

Line No.		Light Type	Minimum Replacement Cost [A]	Deemed Replacement Cost [B]	Average 2 Year Revenue Requirement Factor [C]	Deemed 2 Year Average Revenue Requirement [D] = [B] * [C]
		Mercury Vapor Lights				
1	D	175W Mercury Vapor and Streetlight [1]	$1,686.13	**$670.00**	0.1479	$99.11
2	F	400W Mercury Vapor Streetlight [2]	$1,797.77	**$680.00**	0.1479	$100.59
		Low Pressure Sodium Lights				
3	U	55W Low Pressure Sodium Street Light	$1,873.98	**$990.00**	0.1479	$146.44
4	V	135W Low Pressure Sodium Street Light	$2,199.11	**$1,200.00**	0.1479	$177.50
		High Pressure Sodium Lights				
5	S	70W High Pressure Sodium Street Light [3]	$1,686.13	**$880.00**	0.1479	$130.17
6	A	100W High Pressure Sodium Street Light	$1,686.13	**$900.00**	0.1479	$133.13
7	T	200W High Pressure Sodium Street Light	$1,620.11	**$830.00**	0.1479	$122.77
8	B	250W High Pressure Sodium Street Light	$1,797.77	**$980.00**	0.1479	$144.96
9	I	400W High Pressure Sodium Flood Light	$1,814.12	**$980.00**	0.1479	$144.96
10	C	400W High Pressure Sodium Street Light	$1,798.69	**$980.00**	0.1479	$144.96
		Light Emitting Diode ("LED") Lights				
11	X	40W LED Street Light	$1,755.16	**$179.81**	0.1479	$26.60
12	Y	133W LED Street Light	$1,991.04	**$630.58**	0.1479	$93.28
13	Z	259W LED Street Light	$2,780.21	**$1,170.00**	0.1479	$173.07

Line No.		PoleType	Minimum Replacement Cost [H]	Deemed Replacement Cost [I]	Average 2 Year Revenue Requirement Factor [E]	Deemed 2 Year Average Revenue Requirement [J] = [I] * [E]
14	1	Wood Poles [5]	$1,273.03	$490.00	0.1479	$72.48
15	S	Non-Wood Poles	$1,263.19	$950.00	0.1479	$140.52

Notes
1. 175W Mercury Vapor and Streetlight no longer installed (Assumes 100W High Pressure Sodium Street Light as replacement)
2. 400W Mercury Vapor Streetlight no longer installed (Assumes 250W High Pressure Sodium Street Light as replacement)
3. 70W High Pressure Sodium Street Light is the same light as 100W High Pressure Sodium Street Light (dual wattage head)
4. All Light costs assume lamp, arm, and 150' of secondary.
5. All Light & Pole costs provided by M. Adams (PNM Streetlight Administrator)

<u>Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates</u>

Please note the following concerning Table A:

1. "Deemed Replacement Cost" represents the maximum amount of investment that the Company will place into rate base for each new Company-owned light and pole installed. These values for light and pole types that are available for new installations are included in the SPECIAL CONDITIONS Table at Section 1.a in Rate 20.
2. The Deemed 2 Year Average Revenue Requirements listed in Table A above provides a relative cost basis for deriving the revenue requirements for he Company-owned lights and poles.

The proposed base revenue requirement in this case for Rate 20 is $7,778,400. To apportion this revenue requirement for each light and pole offered in Rate 20, the revenue requirement must be functionalized and allocated as appropriate to each light class. The functional components of this revenue requirement are depicted in Table B-1 below. In Table B-1 below, the CAR discounts that are derived for PNM South light and pole combinations are allocated back to all light types.

<u>Table B-1: Components for Rate 20 Revenue Requirements</u>

Line No.	Description Of Costs		Revenue Requirement	Annual kWh	Rate Per kWh	Notes
1	Common Demand Production (Appl. To All Lights)		$1,068,876	49,850,940	$0.0214414	Common to all lights
2	Common Demand Transmission (Appl. To All Lights)		$193,778	49,850,940	$0.0038872	Common to all lights
3	Common Demand Substation (Appl. To All Lights)		$149,923	49,850,940	$0.0030074	Common to all lights
4	Common Demand Distribution Primary (Appl. To All Lights)		$527,273	49,850,940	$0.0105770	Common to all lights
5	Common Demand Distribution Secondary (Appl. To All Lights)		$376,166	49,850,940	$0.0075458	Common to all lights
6	Common Energy Non-Fuel (Appl. To All Lights)		$382,559	49,850,940	$0.0076741	Common to all lights
7	Common Customer Related (Appl. To All Lights)		$0	49,850,940	$0.0000000	Common to all lights
8	CAR + Rounding (Allocated Back to All Lights)		$323,023	49,850,940	$0.0064798	Common to all lights
9	Total Allocation to All Lights		$3,021,599	49,850,940	$0.0606127	Common to all lights
10	O&M (Alloc. only to MV, LPS and HPS Lights)		$811,809	49,540,512	$0.0163868	Not Appl. To Cust Owned Alt. Lights & Metered Series
11	Intra Class Subsidy (Co. Owned Lts. & Poles)	0%	$0	49,850,940	$0.0000000	Not Appl. To Alt. Lights
12	Co. Owned Lts. & Poles	100%	$4,268,014			Only Appl. To Co. Lights & Poles
13	Company Owned Lights and Poles		$4,268,014			Line 11 + Line 12
14	Total Base Rate Revenue Requirements		$7,778,400			Lines 1 - 7 + Lines 10 - 12

Using Table B-1, costs common to all lights are then allocated to each light type as depicted in Table B-2:

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Table B-2: Components of Common Costs Allocated to Light Types

Line No.		Light Or Pole Type	kWh per Unit	Rate per kWh per Unit	Monthly Common Cost per Unit	Notes
		Mercury Vapor Lights				
15	D	175W Mercury Vapor and Streetlight	73	$0.0769995	$5.62	Rate = Table 1, Lines 9, 10 and 11
16	F	400W Mercury Vapor Streetlight	162	$0.0769995	$12.47	Rate = Table 1, Lines 9, 10 and 11
		Low Pressure Sodium Lights				
17	U	55W Low Pressure Sodium Street Light	28	$0.0769995	$2.16	Rate = Table 1, Lines 9, 10 and 11
18	V	135W Low Pressure Sodium Street Light	63	$0.0769995	$4.85	Rate = Table 1, Lines 9, 10 and 11
		High Pressure Sodium Lights				
19	S	70W High Pressure Sodium Street Light	31	$0.0769995	$2.39	Rate = Table 1, Lines 9, 10 and 11
20	A	100W High Pressure Sodium Street Light	45	$0.0769995	$3.46	Rate = Table 1, Lines 9, 10 and 11
21	T	200W High Pressure Sodium Street Light	89	$0.0769995	$6.85	Rate = Table 1, Lines 9, 10 and 11
22	B	250W High Pressure Sodium Street Light	107	$0.0769995	$8.24	Rate = Table 1, Lines 9, 10 and 11
23	I	400W High Pressure Sodium Flood Light	165	$0.0769995	$12.70	Rate = Table 1, Lines 9, 10 and 11
24	C	400W High Pressure Sodium Street Light	165	$0.0769995	$12.70	Rate = Table 1, Lines 9, 10 and 11
		Metered Lights				
25		Company Owned		$0.0769995	$0.0769995	Rate = Table 1, Lines 9, 10 and 10
26		Customer Owned		$0.0606127	$0.0606127	Rate = Table 1, Line 9

Then, the allocated costs for Company-owned lights and poles (Table B-1, Line 13) are apportioned to Company-owned lights as depicted in Table B-3:

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Table B-3: Costs Allocated to Company-Owned Light and Pole Types

Line No.		Light Or Pole Type	Light Units	Deemed 2 Year Average Revenue Requirement	Allocated Monthly Light and Pole Costs	Allocated Revenue	Test Year Energy	Notes
		Mercury Vapor Lights						
27	D	175W Mercury Vapor and Streetlight	50,628	$99.11	$8.19	$414,643	3,695,844	
28	F	400W Mercury Vapor Streetlight	5,604	$100.59	$8.31	$46,569	907,848	
		Low Pressure Sodium Lights						
29	U	55W Low Pressure Sodium Street Light	11,652	$146.44	$12.10	$140,989	326,256	
30	V	135W Low Pressure Sodium Street Light	288	$177.50	$14.67	$4,225	18,144	
		High Pressure Sodium Lights						
31	S	70W High Pressure Sodium Street Light	312	$130.17	$10.76	$3,357	9,672	
32	A	100W High Pressure Sodium Street Light	116,160	$133.13	$11.00	$1,277,760	5,227,200	
33	T	200W High Pressure Sodium Street Light	11,772	$122.77	$10.15	$119,486	1,047,708	
34	B	250W High Pressure Sodium Street Light	66,900	$144.96	$11.98	$801,462	7,158,300	
35	I	400W High Pressure Sodium Flood Light	8,844	$144.96	$11.98	$105,951	1,459,260	
36	C	400W High Pressure Sodium Street Light	6,168	$144.96	$11.98	$73,893	1,017,720	
		Poles						
37	W	Wood Pole	105,768	$72.48	$5.99	$633,550		
38	X	Non-Wood Pole	49,752	$140.52	$11.62	$578,118		
		Metered Lights						
39		Company Owned	473,460		$0.1432021	$67,800	473,460	
40		Table Totals				$4,267,804	21,341,412	
41		Target Revenue (Co. Owned Lts. & Poles Revenue Requirement)				$4,268,014		
42		Difference				($210)		

The combined results of Table B-2 and B-3 provide the lights and pole rates as depicted in Table B-4 below:

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Table B-4: Rate 20 - Base Rates for Lights and Poles (Both Company-Owned and Customer-Owned)

Line No.		Light Or Pole Type	Company Owned Lights and Poles	Customer Owned Lights and Poles	Notes
		Mercury Vapor Lights			
43	D	175W Mercury Vapor and Streetlight	$13.81	$5.62	Co.-Owned: Ln 15 + Ln 27, Cust.-Owned: Ln 15
44	F	400W Mercury Vapor Streetlight	$20.78	$12.47	Co.-Owned: Ln 16 + Ln 28, Cust.-Owned: Ln 16
		Low Pressure Sodium Lights			
45	U	55W Low Pressure Sodium Street Light	$14.26	$2.16	Co.-Owned: Ln 17 + Ln 29, Cust.-Owned: Ln 17
46	V	135W Low Pressure Sodium Street Light	$19.52	$4.85	Co.-Owned: Ln 18 + Ln 30, Cust.-Owned: Ln 18
		High Pressure Sodium Lights			
47	S	70W High Pressure Sodium Street Light	$13.15	$2.39	Co.-Owned: Ln 19 + Ln 31, Cust.-Owned: Ln 19
48	A	100W High Pressure Sodium Street Light	$14.46	$3.46	Co.-Owned: Ln 20 + Ln 32, Cust.-Owned: Ln 20
49	T	200W High Pressure Sodium Street Light	$17.00	$6.85	Co.-Owned: Ln 21 + Ln 33, Cust.-Owned: Ln 21
50	B	250W High Pressure Sodium Street Light	$20.22	$8.24	Co.-Owned: Ln 22 + Ln 34, Cust.-Owned: Ln 22
51	I	400W High Pressure Sodium Flood Light	$24.68	$12.70	Co.-Owned: Ln 23 + Ln 35, Cust.-Owned: Ln 23
52	C	400W High Pressure Sodium Street Light	$24.68	$12.70	Co.-Owned: Ln 24 + Ln 36, Cust.-Owned: Ln 24
		Poles			
53	W	Wood Pole	$5.99		Co.-Owned: Ln 37
54	X	Non-Wood Pole	$11.62		Co.-Owned: Ln 38
		Metered Lights			
55		Company Owned	$0.2202016		Co.-Owned: Ln 25 + Ln 39
56		Customer Owned		$0.0606127	Cust.-Owned: Ln 26

For the proposed customer-owned and maintained option and the Company-owned and maintained option for LED Lighting, in order to permit maximum flexibility for what a customer chooses to have installed, the Company utilized a wattage range structure. Under this structure, lights will be billed under the appropriate wattage range depicted in Table B-5 below based upon the wattage of each light that the customer selects.

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Table B-5: Monthly Charges for Company-Owned and Maintained LED Lighting and Customer-Owned and Maintained Lighting

Line No.	Fixture Wattage Range *(Wattages include all ballast or driver losses (if applicable))*	Monthly kWh Usage (1), (2)	Company Owned And Maintained Option for LED Lighting-Monthly Charge Per Unit *Monthly kWh Usage * ($0.0606127 per kWh + $0.1560835 per kWh)*	Customer Owned and Maintained Lighting-Monthly Charge Per Unit *Monthly kWh Usage * $0.0606127 per kWh*
1	0.0 to 10.0 Watts	3.6	$0.78	$0.22
2	10.1 to 20.0 Watts	7.1	$1.54	$0.43
3	20.1 to 30.0 Watts	10.7	$2.32	$0.65
4	30.1 to 40.0 Watts	14.2	$3.08	$0.86
5	40.1 to 50.0 Watts	17.8	$3.86	$1.08
6	50.1 to 60.0 Watts	21.3	$4.62	$1.29
7	60.1 to 70.0 Watts	24.9	$5.40	$1.51
8	70.1 to 80.0 Watts	28.4	$6.15	$1.72
9	80.1 to 90.0 Watts	32.0	$6.93	$1.94
10	90.1 to 100.0 Watts	35.6	$7.71	$2.16
11	100.1 to 110.0 Watts	39.1	$8.47	$2.37
12	110.1 to 120.0 Watts	42.7	$9.25	$2.59
13	120.1 to 130.0 Watts	46.2	$10.01	$2.80
14	130.1 to 140.0 Watts	49.8	$10.79	$3.02
15	140.1 to 150.0 Watts	53.3	$11.55	$3.23
16	150.1 to 160.0 Watts	56.9	$12.33	$3.45
17	160.1 to 170.0 Watts	60.4	$13.09	$3.66
18	170.1 to 180.0 Watts	64.0	$13.87	$3.88
19	180.1 to 190.0 Watts	67.5	$14.63	$4.09
20	190.1 to 200.0 Watts	71.1	$15.41	$4.31
21	200.1 to 210.0 Watts	74.7	$16.19	$4.53
22	210.1 to 220.0 Watts	78.2	$16.95	$4.74
23	220.1 to 230.0 Watts	81.8	$17.73	$4.96
24	230.1 to 240.0 Watts	85.3	$18.48	$5.17
25	240.1 to 250.0 Watts	88.9	$19.26	$5.39
26	250.1 to 260.0 Watts	92.4	$20.02	$5.60
27	260.1 to 270.0 Watts	96.0	$20.80	$5.82
28	270.1 to 280.0 Watts	99.5	$21.56	$6.03
29	280.1 to 290.0 Watts	103.1	$22.34	$6.25
30	290.1 to 300.0 Watts	106.7	$23.12	$6.47
31	300.1 to 310.0 Watts	110.2	$23.88	$6.68
32	310.1 to 320.0 Watts	113.8	$24.66	$6.90
33	320.1 to 330.0 Watts	117.3	$25.42	$7.11
34	330.1 to 340.0 Watts	120.9	$26.20	$7.33
35	340.1 to 350.0 Watts	124.4	$26.96	$7.54
36	350.1 to 360.0 Watts	128.0	$27.74	$7.76
37	360.1 to 370.0 Watts	131.5	$28.50	$7.97
38	370.1 to 380.0 Watts	135.1	$29.28	$8.19
39	380.1 to 390.0 Watts	138.6	$30.03	$8.40
40	390.1 to 400.0 Watts	142.2	$30.81	$8.62

Notes

(1) Monthly kWh usage = Maximum Wattage in range x 355.5 hours per month / 1,000 Watts per kW.

(2) For lights larger than 400W, the applicable usage and rate shall be the sum of the 390.1 - 400.0 Watts row in the table above plus a wattage range such that the resulting range encompasses the actual wattage of the light (Example: for a 600 Watt light, the applicable usage and charge is determined by adding the 390.1 – 400.0 Watts row and the 190.1 – 200.0 Watts row together, resulting in a 590.1 – 600.0 Watt Range with a monthly usage of 213.3 kWh.)

<u>Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates</u>

Concurrent with the Rate 20 light and pole rates calculated above, Rider 35 Consolidation Adjustment Rider ("CAR") rates were also calculated utilizing the following criteria:

1. All CAR rates are credits: If a PNM South light-pole combination does not currently have an applicable CAR, no proposed CAR rate was calculated.
2. The current CAR credit rate for Company-owned metered Streetlights was reduced to ($0.0900000) per kWh (@7.2%).
3. The current CAR credit rates were reduced by $0.88 per unit per month for the following light types / wattages:
    a. 175W Mercury Vapor
    b. 55W Low Pressure Sodium
    c. 100W High Pressure Sodium
    d. 200W High Pressure Sodium
4. The current CAR credit rates were reduced by $1.78 per unit per month for the following light types / wattages:
    a. 400W Mercury Vapor
    b. 135W Low Pressure Sodium
    c. 400W High Pressure Sodium

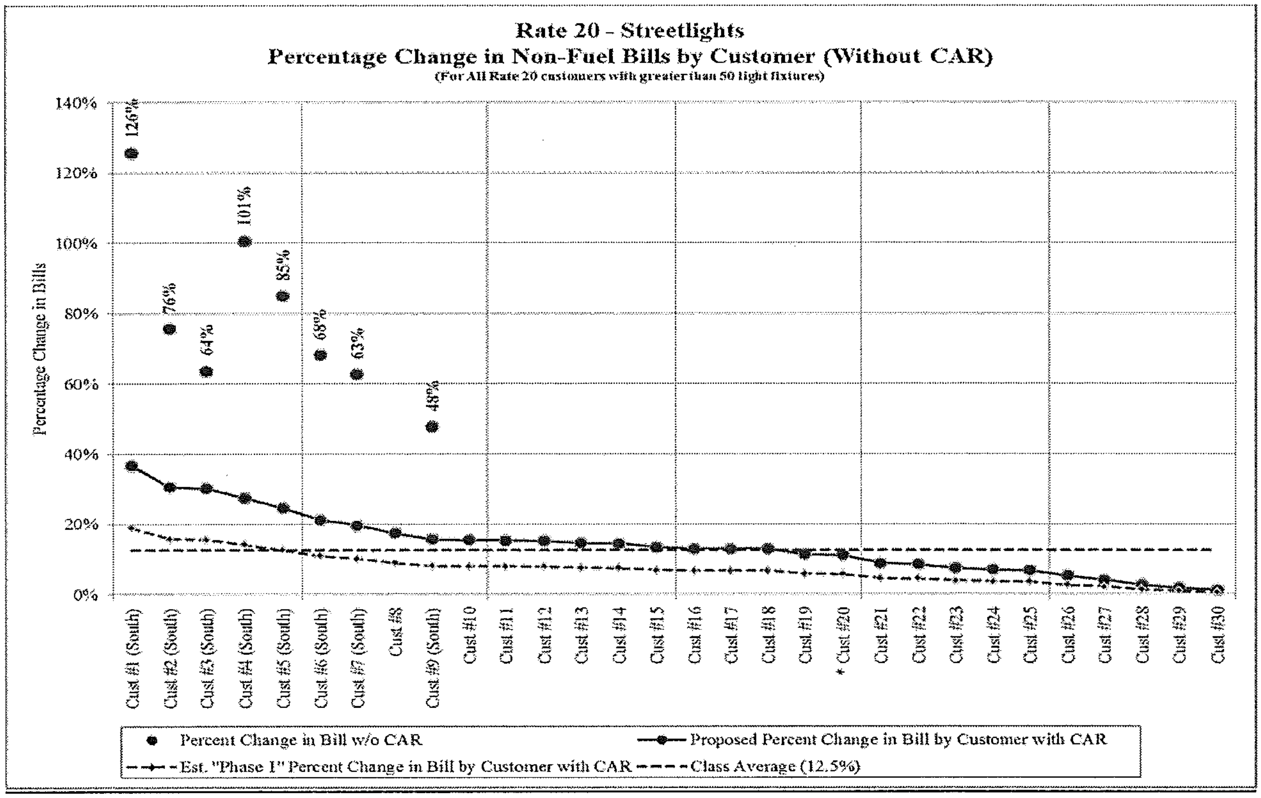
Table C below depicts the proposed CAR rates:

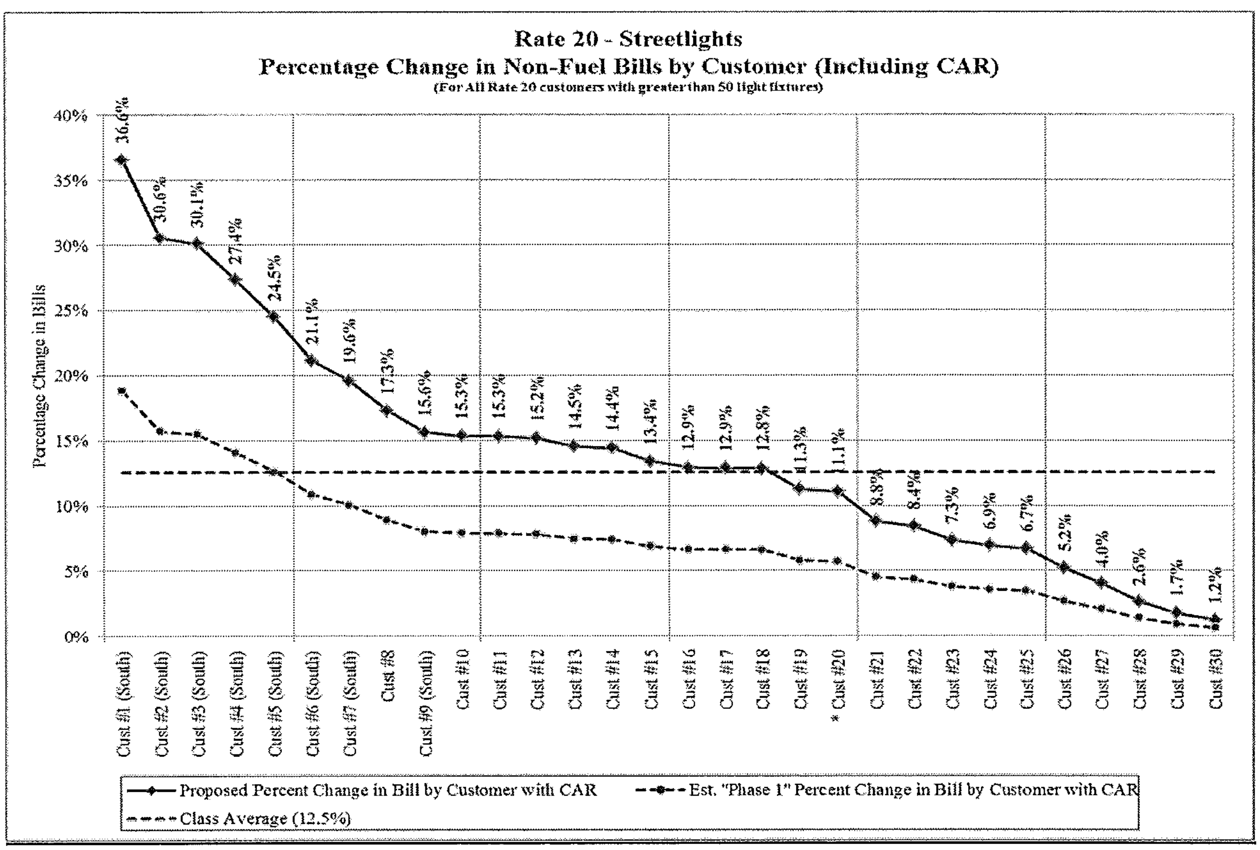
Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

Table C: Calculation of Proposed PNM South CAR Rates by Light and Pole Type

Line No.	Banner Rate (PNM South)	Rate Description	Current Non-Fuel kWh / Light Rate	Current Non-Fuel Pole Rate	Current Non-Fuel CAR Rate	Current Non-Fuel Total Rate	Proposed Non-Fuel kWh / Light Rate	Proposed Pole Rate	Proposed CAR Rate	Proposed Total Rate
			[A]	[B]	[C]	[D] = [A] + [B] + [C]	[A]	[B]	[C]	[D] = [A] + [B] + [C]
1	L2Z5	Metered Streetlighting (Cust Owned)	$0.0561839	$0.0000000	$0.0000000	$0.0561839	$0.0606127	$0.0000000	$0.0000000	$0.0606127
2	L3D1	175W MV SL (Cust, 1x73 kWh/Unit)	$5.54	$0.00	$0.00	$5.54	$5.62	$0.00	$0.00	$5.62
3	L7D1	175W MV SL (Cust, 1x73 kWh/Unit)	$5.54	$0.00	$0.00	$5.54	$5.62	$0.00	$0.00	$5.62
4	L8D1	175W MV SL (Cust, 1x73 kWh/Unit)	$5.54	$0.00	$0.00	$5.54	$5.62	$0.00	$0.00	$5.62
5	L7D3	175W MV SL (Cust, 1x73 kWh/Unit)	$5.54	$0.00	$0.00	$5.54	$5.62	$0.00	$0.00	$5.62
6	L8D3	175W MV SL (Cust, 1x73 kWh/Unit)	$5.54	$0.00	$0.00	$5.54	$5.62	$0.00	$0.00	$5.62
7	L7F1	400W MV SL (Cust, 1x162 kWh/Unit)	$12.30	$0.00	$0.00	$12.30	$12.47	$0.00	$0.00	$12.47
8	L8F1	400W MV SL (Cust, 1x162 kWh/Unit)	$12.30	$0.00	$0.00	$12.30	$12.47	$0.00	$0.00	$12.47
9	L7F3	400W MV SL (Cust, 1x162 kWh/Unit)	$12.30	$0.00	$0.00	$12.30	$12.47	$0.00	$0.00	$12.47
10	L8F3	400W MV SL (Cust, 1x162 kWh/Unit)	$12.30	$0.00	$0.00	$12.30	$12.47	$0.00	$0.00	$12.47
11	L7A1	100W HPS SL (Cust, 1x45 kWh/Unit)	$3.42	$0.00	$0.00	$3.42	$3.46	$0.00	$0.00	$3.46
12	L8A1	100W HPS SL (Cust, 1x45 kWh/Unit)	$3.42	$0.00	$0.00	$3.42	$3.46	$0.00	$0.00	$3.46
13	L7A3	100W HPS SL (Cust, 1x45 kWh/Unit)	$3.42	$0.00	$0.00	$3.42	$3.46	$0.00	$0.00	$3.46
14	L8A3	100W HPS SL (Cust, 1x45 kWh/Unit)	$3.42	$0.00	$0.00	$3.42	$3.46	$0.00	$0.00	$3.46
15	L7T1	200W HPS SL (Cust, 1x89 kWh/Unit)	$6.76	$0.00	$0.00	$6.76	$6.85	$0.00	$0.00	$6.85
16	L8T1	200W HPS SL (Cust, 1x89 kWh/Unit)	$6.76	$0.00	$0.00	$6.76	$6.85	$0.00	$0.00	$6.85
17	L7T3	200W HPS SL (Cust, 1x89 kWh/Unit)	$6.76	$0.00	$0.00	$6.76	$6.85	$0.00	$0.00	$6.85
18	L8T3	200W HPS SL (Cust, 1x89 kWh/Unit)	$6.76	$0.00	$0.00	$6.76	$6.85	$0.00	$0.00	$6.85
19	L7C1	400W HPS SL (Cust, 1x165 kWh/Unit)	$12.53	$0.00	$0.00	$12.53	$12.70	$0.00	$0.00	$12.70
20	L8C1	400W HPS SL (Cust, 1x165 kWh/Unit)	$12.53	$0.00	$0.00	$12.53	$12.70	$0.00	$0.00	$12.70
21	L7C3	400W HPS SL (Cust, 1x165 kWh/Unit)	$12.53	$0.00	$0.00	$12.53	$12.70	$0.00	$0.00	$12.70
22	L8C3	400W HPS SL (Cust, 1x165 kWh/Unit)	$12.53	$0.00	$0.00	$12.53	$12.70	$0.00	$0.00	$12.70
23	L1Z5	Metered Streetlighting (PNM Owned)	$0.1940070	$0.0000000	($0.0970103)	$0.0969967	$0.2202016	$0.0000000	($0.0900000)	$0.1302016
24	L3D2	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$4.86	($11.90)	$7.10	$13.81	$5.99	($11.02)	$8.78
25	L4D2	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$9.45	($16.49)	$7.10	$13.81	$11.62	($15.61)	$9.82
26	L7D2	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$0.00	($7.04)	$7.10	$13.81	$0.00	($6.16)	$7.65
27	L8D2	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$0.00	($7.04)	$7.10	$13.81	$0.00	($6.16)	$7.65
28	L3D4	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$4.86	($11.90)	$7.10	$13.81	$5.99	($11.02)	$8.78
29	L4D4	175W MV SL (PNM, 1x73 kWh/Unit)	$14.14	$9.45	($16.49)	$7.10	$13.81	$11.62	($15.61)	$9.82
30	L3F2	400W MV SL (PNM, 1x162 kWh/Unit)	$21.47	$4.86	($10.34)	$15.99	$20.78	$5.99	($8.56)	$18.21
31	L4F2	400W MV SL (PNM, 1x162 kWh/Unit)	$21.47	$9.45	($12.24)	$18.68	$20.78	$11.62	($10.46)	$21.94
32	L7F2	400W MV SL (PNM, 1x162 kWh/Unit)	$21.47	$0.00	($5.48)	$15.99	$20.78	$0.00	($3.70)	$17.08
33	L8F2	400W MV SL (PNM, 1x162 kWh/Unit)	$21.47	$0.00	($2.79)	$18.68	$20.78	$0.00	($1.01)	$19.77
34	L4F4	400W MV SL (PNM, 1x162 kWh/Unit)	$21.47	$9.45	($12.24)	$18.68	$20.78	$11.62	($10.46)	$21.94
35	L3U2	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$4.86	($7.39)	$10.17	$14.26	$5.99	($6.51)	$13.74
36	L4U2	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$9.45	($11.98)	$10.17	$14.26	$11.62	($11.10)	$14.78
37	L7U2	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$0.00	($2.53)	$10.17	$14.26	$0.00	($1.65)	$12.61
38	L8U2	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$0.00	($2.53)	$10.17	$14.26	$0.00	($1.65)	$12.61
39	L3U4	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$4.86	($7.39)	$10.17	$14.26	$5.99	($6.51)	$13.74
40	L4U4	55W LPS SL (PNM, 1x28 kWh/Unit)	$12.70	$9.45	($11.98)	$10.17	$14.26	$11.62	($11.10)	$14.78
41	L3V2	135W LPS SL (PNM, 1x63 kWh/Unit)	$17.13	$4.86	($7.68)	$14.31	$19.52	$5.99	($5.90)	$19.61
42	L7V2	135W LPS SL (PNM, 1x63 kWh/Unit)	$17.13	$0.00	($2.82)	$14.31	$19.52	$0.00	($1.04)	$18.48
43	L4V4	135W LPS SL (PNM, 1x63 kWh/Unit)	$17.13	$9.45	($12.27)	$14.31	$19.52	$11.62	($10.49)	$20.65
44	L3A2	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$4.86	($6.93)	$9.95	$14.46	$5.99	($6.05)	$14.40
45	L4A2	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$9.45	($2.64)	$18.83	$14.46	$11.62	($1.76)	$24.32
46	L7A2	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$0.00	($2.07)	$9.95	$14.46	$0.00	($1.19)	$13.27
47	L8A2	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$0.00	$0.00	$12.02	$14.46	$0.00	$0.00	$14.46
48	L3A4	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$4.86	($3.83)	$13.05	$14.46	$5.99	($2.95)	$17.50
49	L4A4	100W HPS SL (PNM, 1x45 kWh/Unit)	$12.02	$9.45	($8.42)	$13.05	$14.46	$11.62	($7.54)	$18.54
50	L3T2	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$4.86	($7.70)	$12.15	$17.00	$5.99	($6.82)	$16.17
51	L4T2	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$9.45	($3.95)	$20.49	$17.00	$11.62	($3.07)	$25.55
52	L7T2	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$0.00	($2.84)	$12.15	$17.00	$0.00	($1.96)	$15.04
53	L8T2	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$0.00	$0.00	$14.99	$17.00	$0.00	$0.00	$17.00
54	L3T4	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$4.86	($5.02)	$14.83	$17.00	$5.99	($4.14)	$18.85
55	L4T4	200W HPS SL (PNM, 1x89 kWh/Unit)	$14.99	$9.45	($2.98)	$21.46	$17.00	$11.62	($2.10)	$26.52
56	L3C2	400W HPS SL (PNM, 1x165 kWh/Unit)	$21.70	$4.86	($10.61)	$15.95	$24.68	$5.99	($8.83)	$21.84
57	L4C2	400W HPS SL (PNM, 1x165 kWh/Unit)	$21.70	$9.45	($7.67)	$23.48	$24.68	$11.62	($5.89)	$30.41
58	L7C2	400W HPS SL (PNM, 1x165 kWh/Unit)	$21.70	$0.00	($5.75)	$15.95	$24.68	$0.00	($3.97)	$20.71
59	L8C2	400W HPS SL (PNM, 1x165 kWh/Unit)	$21.70	$0.00	$0.00	$21.70	$24.68	$0.00	$0.00	$24.68
60	L4C4	400W HPS SL (PNM, 1x165 kWh/Unit)	$21.70	$9.45	($7.67)	$23.48	$24.68	$11.62	($5.89)	$30.41

Summary of Modifications to Rate 20 (Streetlighting) and the Rider 35 (CAR) Rates

1 

2 

Summary of Discussions with Stakeholders Regarding Rate 20 – Integrated System Streetlighting and Floodlighting Service

PNM Exhibit JCA-13

Is contained in the following 3 pages

PNM MEETING WITH STREETLIGHTING STAKEHOLDERS

SUMMARY **OCTOBER 24, 2016** **2:30PM** **PNM HEADQUARTERS**

MEETING CALLED BY	Public Service Company of New Mexico
ATTENDEES	**In Person:** Ernest Jaramillo- City of Las Vegas, Tony Gurule – City of Albuquerque, Antoinette Baldonado – City of Albuquerque, Sai Ishmael – City of Albuquerque, Keen Heinzelman – Village of Los Ranchos, Jane Yee – City of Albuquerque, Chuck Noble – CCAE, Jeff Albright – Bernalillo County, Mark Fenton/Amy Miller/Stella Chan/Stacey Goodwin/Debrea Terwilliger/Julio Aguirre/Patrick Hall/Ray Vigil/Jack Ingalls/Mike Adams/Erfan Hakimian – PNM **By Phone:** Joseph Yar – NMAG, Adam Bickford – SWEEP, John Reynolds – NMPRC Staff, Adam Gutman/Chris Gosling – Citelum, John Romero – City of Santa Fe, Johnny Baca – Santa Fe County Public Works, Leonard Rivera – City of Rio Rancho, John Alejandro – City of Santa Fe, Jean-Christopher Florenson & Larry Gardner – City of Alamogordo

Agenda topics

TOPIC #1 100,000 HOUR LIGHTS — JACK INGALLS– PNM

DISCUSSION

PNM explained that since the submittal of the 2015 PNM rate case (Case No. 15-00261-UT) 100,000 hour LED lighting technology has come onto the market and has been tested by PNM.

PNM anticipates a near-term Advice Notice filing with updated language changes to the recently approved Rate Schedule 20 that would permit Company-owned LED lights that are rated at 100,000 hours. This anticipated tariff filing will propose the removal of set wattage numbers for Company-owned LED lights, such that as new LED lights become available on the market and are tested by PNM, the Company may provide its customers with more efficient Company-owned LED lights in between rate cases or tariff filings. This anticipated tariff filing will not propose any changes to the underlying rate design and will not modify the rates reflected in the approved Rate 20 schedule.

Tony Gurule from the City of Albuquerque asked who will decide which wattages will be used. PNM stated it will maintain three LED lights as operational substitutes for nearly all of PNM's standard lighting options. PNM will maintain approximately a 3-month inventory of the luminaires and would update its three operational substitutes with new technology as the technology becomes available. The inventory levels will be determined as PNM gains more experience with the level of demand.

Chuck Noble of CCAE asked if the language change would affect the rates in the tariff, specifically the Company-owned and maintained charges. PNM explained that this proposed change would not affect the rates.

Tony Gurule from the City of Albuquerque asked if a customer could request a 7 pin smart control receptacle. PNM explained that current PNM standards include an ANSI 7 pin receptacle.

CONCLUSIONS

The City of Albuquerque and SWEEP expressed agreement with this proposal. Jeff Albright, counsel for Santa Fe and Bernalillo Counties, stated that he had to confer with his clients, but they would most likely be in agreement with this proposal.

ACTION ITEMS

PNM will be filing a revision to its Rate 20 – Streetlighting tariff outside of a rate case to remove set wattages from the tariff for the LED lighting options, which will permit PNM to install 100,000 hour LED Company-owned lights and provide for a more efficient process for updating its LED lighting options. PNM intends to make this filing outside of a rate case as described in Topic 1 above in hopes that the change will be implemented within 30 days of filing by operation of law instead of having to wait for the duration of the rate case.

PNM will revise the language of the tariff and circulate it to interested stakeholders for comment prior to filing with the Commission.

TOPIC #2 EXPANDED LIGHTING RANGE OPTIONS FOR CONVERSION — JACK INGALLS - PNM

DISCUSSION

PNM explained that currently, nearly all standard streetlights offered under Rate 20 have an LED operational substitute. For example, 175W MV, 55W LPS, 70W HPS, and 100W HPS fixtures all output roughly the same amount of lumens and would convert to the same LED fixture. Similarly, 400W MV, 135W LPS, 200W HPS, and 250W HPS fixtures would all convert to the same LED fixture as well. As noted in TOPIC #1, as part of the anticipated tariff filing, the Company plans to remove the reference to a specific wattage number regarding the Company-owned LED lights such that as more efficient LED lights become available on the market and are tested by PNM, the Company may make those new operational substitutes available to its customers.

Tony Gurule of City of Albuquerque asked how long PNM's testing period would be to determine if a particular LED streetlight was available to customers for purposes of replacing Company-owned lighting. PNM stated that it would take approximately 3 months to get a new light added to PNM's approved list, which was based on the approximate time between meetings of the PNM standards committee.

Adam Bickford of SWEEP asked how PNM would communicate it to customers. PNM explained it didn't have a communication plan developed at this time but it would plan to maintain a list of approved lights in a public location where all customers would be able to access it. PNM's account managers also would also work directly with customers and most likely be involved in communication to customers about changes to the streetlighting processes. PNM cautioned that it would have to get Staff and Commission buy-off on maintaining the list of approved LED streetlighting options outside of the tariff.

CONCLUSIONS

See conclusion to TOPIC #1 above.

ACTION ITEMS

See action items to TOPIC #1 above.

TOPIC #3 INSTALLATION ALLOWANCES — JULIO AGUIRRE – PNM

DISCUSSION

PNM informed the group that installation allowances are the amounts specified in the recently approved Rate 20 that the Company covers for standard and LED lights and poles if the customer requests the installation or replacement of Company-owned lights. The difference between the actual cost of the installation and the installation allowance set forth in Rate 20 is the responsibility of the customer. These allowances facilitate a gradual transition to more cost-based streetlighting rates and limit the rate impact on certain customers. The current average allowance for streetlights is approximately 51% of the total installation cost. A balance is struck for the level of installation allowances, which means higher allowances will result in lower upfront costs but higher monthly rates. Lower allowances will result in higher upfront costs but lower monthly rates.

Jeff Albright, Counsel for Bernalillo County if there are economies of scale for installation. PNM explained that its tariff is designed assuming individual and not mass replacements. Also, it was discussed to the extent economies of scale exist, the tariff is designed for the customer to receive such benefit in that all economies of scale would be captured by the customer as part of its portion of total installation costs.

CONCLUSIONS

Not applicable.

ACTION ITEMS

Not applicable.

TOPIC #4 SALVAGE VALUES AND RECOVERY OF UNDEPRECIATED ASSETS — DEBREA TERWILLIGER - PNM

DISCUSSION

PNM explained that based on the recently approved depreciation rates, the Company is expecting that the cost of removal will be greater than any recovery the Company receives from the scrap or other value of its physical assets, which results in a negative net salvage value for streetlights. For any investment that is not fully depreciated when replaced, the Company expects to recover the undepreciated value.

Adam Bickford of SWEEP asked if PNM has tried to estimate if the salvage amounts and installation costs would change for a mass replacement of lights making it beneficial for a city to perform a mass replacement of lights. PNM explained that it has not performed this analysis because it has not yet had a customer request to perform such an estimate for this type of project.

Tony Gurule asked if there were different depreciation rates for different lights. PNM explained that streetlight depreciation is determined based on a single FERC asset account, which takes into account the life and retirement of all of the lights in that account and comes up with a single deprecation rate for all streetlights.

Jane Yee from the City of Albuquerque asked if PNM depreciated "knock downs". While there may have been some confusion as part of this discussion, PNM clarifies that once PNM had been reimbursed for the knock down, the reimbursement is treated as contribution-in-aid of construction (CIAC) and is an offset to plant-in-service. Jane Yee stated that she would keep this as a "parking Lot" issue.

CONCLUSIONS

Not applicable.

ACTION ITEMS

Not applicable.

TOPIC #5 METERING AND ADVANCING LIGHTING CONTROL OPTIONS AT THE REQUEST OF CUSTOMERS — DEBREA TERWILLIGER - PNM

DISCUSSION

PNM explained that LED technology may permit remote metering and control capabilities at each light. However, there are open issues that need to be addressed for remote metering and control, including:

- Who owns or maintains the technology?
- Who verifies the accuracy of the usage measured?
- How the remote metering may or may not interact with Company-owned meters and/or the Company's billing system?
- How this technology will comply with the PRC's metering regulations?.
- Integration of the "Smart Lighting Control Network" with PNM's metering operation and billing system.

The City of Albuquerque and PNM agreed that in order to consider this type of technology, regular technical meetings would need to be held to work through some of the issues with the appropriate parties (including regulatory and legal).

Rio Rancho expressed an interest in attending these types of meetings and stated that they too were looking into new streetlighting technologies.

CONCLUSIONS

PNM and the City of Albuquerque intend to meet on a consistent basis to work through the issues regarding consideration of new streetlighting technologies. Others that are interested in attending, such as the City of Rio Rancho, will be invited.

ACTION ITEMS

PNM will set up future meetings with the City of Albuquerque and other interested stakeholders as requested to discuss implementation of new technologies.

Rate Design for Rate 6 – Private Lighting

PNM Exhibit JCA-14

Is contained in the following 3 pages

Rate 6 Private Lighting Rate Design Workpaper #1

Table 1: By Rate Code Proof-Of Revenue - Current and Proposed Rates

Line No.	Light / Pole Description - (Rate Code)	Determinants	Current Rates	Current Revenues	Proposed Rates	Proposed Revenues
1	175W MV Lt. (73 kWh) - (LA12)	30,432 Units	$11.39	$346,620	$13.10	$398,659
2	175W MV Lt (73 kWh) - (LA1A)	14,304 Units	$11.39	$162,923	$13.10	$187,382
3	400W MV Lt (162 kWh) - (LAFA)	2,820 Units	$22.55	$63,591	$26.30	$74,166
4	400W MH Lt (162 kWh) - (LAMA)	3,036 Units	$24.54	$74,503	$28.16	$85,494
5	1,000W MH Lt (380 kWh) - (LANA)	264 Units	$53.03	$14,000	$61.84	$16,326
6	100W HPS Lt (45 kWh) - (LA32)	62,688 Units	$9.15	$573,595	$10.16	$636,910
7	100W HPS Lt (45 kWh) - (LA3A)	26,604 Units	$9.15	$243,427	$10.16	$270,297
8	200W HPS Lt (89 kWh) - (LAOA)	672 Units	$14.94	$10,040	$16.83	$11,310
9	200W HPS Lt (89 kWh) - (LATA)	10,128 Units	$14.94	$151,312	$16.83	$170,454
10	400W HPS FL (165 kWh) - (LA42)	22,056 Units	$24.99	$551,179	$28.80	$635,213
11	400W HPS FL (165 kWh) (30' Wood Pole) - (LB42)	6,276 Units	$27.98	$175,602	$31.38	$196,941
12	400W HPS FL (165 kWh) (35' Wood Pole) - (LC42)	8,124 Units	$27.98	$227,310	$31.38	$254,931
13	400W HPS FL (165 kWh) (40' Wood Pole) - (LD42)	180 Units	$27.98	$5,036	$31.38	$5,648
14	400W HPS Lt (165 kWh) - (LA4A)	300 Units	$24.99	$7,497	$28.80	$8,640
15	Pole Charge (wood) - (L0LA)	20,784 Units	$2.99	$62,144	$2.58	$53,623
16	175W MV Lt. (73 kWh) - (LA12)	2,221,536 kWh				
17	175W MV Lt (73 kWh) - (LA1A)	1,044,192 kWh				
18	400W MV Lt (162 kWh) - (LAFA)	456,840 kWh				
19	400W MH Lt (162 kWh) - (LAMA)	491,832 kWh				
20	1,000W MH Lt (380 kWh) - (LANA)	100,320 kWh				
21	100W HPS Lt (45 kWh) - (LA32)	2,820,960 kWh				
22	100W HPS Lt (45 kWh) - (LA3A)	1,197,180 kWh				
23	200W HPS Lt (89 kWh) - (LAOA)	59,808 kWh				
24	200W HPS Lt (89 kWh) - (LATA)	901,392 kWh				
25	400W HPS FL (165 kWh) - (LA42)	3,639,240 kWh				
26	400W HPS FL (165 kWh) (30' Wood Pole) - (LB42)	1,035,540 kWh				
27	400W HPS FL (165 kWh) (35' Wood Pole) - (LC42)	1,340,460 kWh				
28	400W HPS FL (165 kWh) (40' Wood Pole) - (LD42)	29,700 kWh				
29	400W HPS Lt (165 kWh) - (LA4A)	49,500 kWh				
30	Pole Charge (wood) - (L0LA)	0 kWh				
31	Class kWh	15,388,500 kWh				
32	Totals	15,388,500		$2,668,780		$3,005,994
33	Target Totals	15,388,500		$2,668,780		$3,006,012
34	Difference From Targets			$0		($18)

Rate 6 Private Lighting Rate Design Workpaper #2

Proposed Light and Pole Rate Design

Table 1: Class Revenue Requirements by Category

Line No.	Category of Revenue	Revenue Requirement
1	Base Generation	$801,871
2	Base Transmission	$145,372
3	Base Substation	$124,097
4	Base Primary Distribution	$429,305
5	Base Secondary Distribution	$304,649
6	Base Fuel Related Non-Fuel	$287,002
7	Base Customer Costs	$0
8	Base Lighting O$M	$250,598
9	Base Company Owned Lights and Pol€	$663,118
10	Total Revenue Requirements	$3,006,012

Table 2: Proposed Light and Pole Rate Design and Component Proof-Of-Revenue

Line No.	Component Type and Description	Monthly kWh per Unit	Light and Pole Units	kWh Usage	Deemed Replacement Cost	Class Deemed Replacement Cost	Base Company Owned Lights and Poles Allocator	Allocation of Base Company Owned Lights and Poles	Company Owned Light & Pole Recovery	Remaining Private Light Revenue Requirement	Final Adjustment	Proposed Light and Pole Rates	Component Proof-Of-Revenue
		[A]	[B]	[C] = [A] * [B]	[D] (See Schedule 6 Private Lighting Rate Design Workpaper #3, Item [B])	[E] = [B] * [D]	[F] = [E] / Sum of [E]	[G] = $663,118 * [F]	[H] = [F] / [B]	[I] = $2,342,894 / 15,388,500 kWh * [A]	[J]	[L] = [H] + [I] + [J] + [K]	[M] = [B] * [J]
11	Area Lights 175W MV AL	73	44,736	3,265,728	$978.77	$3,648,855	0.133898	$88,790	$1.98	$11.11	$0.01	**$13.10**	$586,042
12	Area Lights 400W MV AL	162	2,820	456,840	$810.06	$190,364	0.006986	$4,632	$1.64	$24.66		**$26.30**	$74,166
13	Area Lights 100W HPS AL	45	89,292	4,018,140	$1,631.28	$12,138,354	0.445428	$295,372	$3.31	$6.85		**$10.16**	$907,207
14	Area Lights 200W HPS AL	89	10,128	901,392	$1,620.11	$1,367,373	0.050177	$33,273	$3.29	$13.55	($0.01)	**$16.83**	$170,454
15	Flood Lights 200W HPS FL	89	672	59,808	$1,620.11	$90,726	0.003329	$2,208	$3.29	$13.55	($0.01)	**$16.83**	$11,310
16	Flood Lights 400W HPS FL	165	36,936	6,094,440	$1,814.12	$5,583,861	0.204905	$135,876	$3.68	$25.12		**$28.80**	$1,063,757
17	Flood Lights 400W MH FL	162	3,036	491,832	$1,724.75	$436,362	0.016013	$10,618	$3.50	$24.66		**$28.16**	$85,494
18	Flood Lights 1,000W MH FL	380	264	100,320	$1,974.87	$43,447	0.001594	$1,057	$4.00	$57.85	($0.01)	**$61.84**	$16,326
19	Poles Wood		20,784		$1,273.03	$2,204,888	0.080910	$53,653	$2.58	$0.00		**$2.58**	$53,623
20	Poles 30' Wood		6,276		$1,273.03	$665,795	0.024432	$16,201	$2.58	$0.00		**$2.58**	$16,192
21	Poles 35' Wood		8,124		$1,273.03	$861,841	0.031626	$20,972	$2.58	$0.00		**$2.58**	$20,960
22	Poles 40' Wood		180		$1,273.03	$19,095	0.000701	$465	$2.58	$0.00		**$2.58**	$464
23	Totals		223,248	15,388,500		$27,250,962	1.000000	$663,118					$3,005,994
24	Target Totals												$3,006,012

Schedule 6 Private Lighting Rate Design Workpaper #3

Deemed Replacement Costs for PNM Owned Lights & Poles

Line No.	Light Type		Replacement Cost [A]	Deemed Replacement Cost [B]
	Area Lights			
1	175W Mercury Vapor Area Light	1	$1,631.28	$978.77
2	400W Mercury Vapor Area Light	2	$1,620.11	$810.06
3	100W High Pressure Sodium Area Light		$1,631.28	$1,631.28
4	200W High Pressure Area Light		$1,620.11	$1,620.11
	Flood Lights			
5	200W High Pressure Floodlight		$1,620.11	$1,620.11
6	400W High Pressure Sodium Floodlight		$1,814.12	$1,814.12
7	400W Metal Halide Floodlight		$1,724.75	$1,724.75
8	1,000W Metal Halide Floodlight		$1,974.87	$1,974.87
	Poles			
9	Wood Pole Min Cost		$1,273.03	$1,273.03

Notes

1) 175W Mercury Vapor Area Light no longer available (Assumes 100W High Pressure Sodium Area Light as replacement)
2) 400W Mercury Vapor Area Light no longer available (Assumes 200W High Pressure Area Light as replacement)
3) All Light costs assume lamp, arm, and 150' of secondary.
4) All Light & Pole costs provided by M. Adams (PNM Streetlight Administrator)

Rate 20 – Streetlighting Tariff in Legislative Format

PNM Exhibit JCA-15

Is contained in the following 9 pages

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

16~~5~~TH REVISED RATE NO. 20
CANCELING 15~~4~~TH REVISED RATE NO. 20

INTEGRATED SYSTEM STREETLIGHTING
AND FLOODLIGHTING SERVICE

APPLICABILITY: Applicable to streetlighting and floodlighting systems and under contract with any municipal corporation or other political subdivision within the State of New Mexico.

AVAILABILITY: Available within all areas served by the company in New Mexico.

DEFINITIONS: x

A. Appendix A: Appendix A shall be a list of Company-owned LED streetlights that are operational x
substitutes for standard Mercury Vapor ("MV"), Low Pressure Sodium ("LPS") and High Pressure x
Sodium ("HPS") fixtures. Appendix A shall be publicly available on the Company's website and x
shall be updated periodically by the Company to reflect updates for operational substitutes x
currently available from suppliers. x

B. Operational Substitute No. 1: Operational Substitute No. 1 shall be a Company-owned LED light x
identified in Appendix A to this tariff that is an operational substitute for the existing 175W MV, x
55W LPS, 70W HPS and 100W HPS streetlight fixtures. x

C. Operational Substitute No. 2: Operational Substitute No. 2 shall be a Company-owned LED light x
identified in Appendix A to this tariff that is an operational substitute for the existing 400W MV, x
135W LPS, 200W HPS and 250W HPS streetlight fixtures. x

~~A.~~D. Operational Substitute No. 3: Operational Substitute No. 3 shall be a Company-owned x
LED light identified in Appendix A to this tariff that is an operational substitute for a 400W HPS x
streetlight fixture. x

MINIMUM CHARGE: Payment for lamps, standards, and lighting fixtures installed in accordance with the rates specified below.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from the date of bill. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional late payment charge as defined in Rate 16 Special Charges.

NET RATE PER MONTH OR PART THEREOF: The charge per month will be the sum of the applicable components of A, B, C, D, E, F and G. All monthly kWh listed for unmetered lighting assumes dusk-to-dawn operation at an average of 355.5 hours per month.

A. LIGHT CHARGE (for unmetered lights where maintenance is provided by the Company and included in the Monthly Charge):

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Standard Light Type	Monthly kWh Usage	Monthly Charge (Company Owned)	Monthly Charge (Customer Owned)	
Mercury Vapor ~~("MV")~~ Lights (1)				X
175W MV	73	$13.81~~14.14~~	$ 5.62~~54~~	
400W MV	162	$20.78~~21.47~~	$12.47~~30~~	X
Low Pressure Sodium ~~("LPS")~~ Lights (1)				
55W LPS	28	$14.26~~12.70~~	$ 2.16~~3~~	X
135W LPS	63	$19.52~~17.13~~	$ 4.85~~78~~	
High Pressure Sodium ~~("HPS")~~ Lights				
70W HPS	31	$13.15~~10.95~~	$ 2.39~~5~~	
100W HPS	45	$14.46~~12.02~~	$ 3.46~~2~~	
200W HPS	89	$17.00~~14.99~~	$6.85~~76~~	
250W HPS	107	$20.22~~17.29~~	$8.24~~12~~	
400W HPS	165	$24.68~~21.70~~	$12.70~~53~~	

(1) Service under this rate is restricted to those installations and customers receiving service as of August 21, 2011.

B. METERED SERIES STREET LIGHTING: For PNM owned and maintained metered lights, and customer owned metered lights where maintenance is provided by the Company and is included in the monthly charge.

Monthly Rate Monthly Rate

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Description	(Company Owned (1))	(Customer Owned)
Metered Lighting	$0.~~1940070~~2202016	$0.0606127~~561839~~

(1) Service under this rate is restricted to those installations receiving service as of August 21, 2011.

C. COMPANY OWNED AND MAINTAINED LED LIGHTING, AND CUSTOMER OWNED AND MAINTAINED LIGHTING (for unmetered lights where maintenance is not provided by the Company and is not included in the Monthly Charge):

Fixture Wattage Range (Wattage includes all ballast or driver losses (if applicable))				Monthly kWh Usage (1), (2)	Company Owned And Maintained Option for LED Lighting-Monthly Charge Per Unit Monthly kWh Usage * ($0.~~0561839~~ 0606127 per kWh + $0.~~1441851~~ 141560835per kWh)		Customer Owned and Maintained Lighting-Monthly Charge Per Unit Monthly kWh Usage * $0.~~0561839~~ 0606127 per kWh
0.0	to	10.0	Watts	3.6	$ 0.78~~0.71~~		$ 0.22~~0.20~~
10.1	to	20.0	Watts	7.1	$ ~~1.42~~1.54		$ 0.43~~0.40~~
20.1	to	30.0	Watts	10.7	$ ~~2.14~~2.32		$ 0.65~~0.60~~
30.1	to	40.0	Watts	14.2	$ ~~2.85~~3.08	~~(3)~~	$ 0.86~~0.80~~
40.1	to	50.0	Watts	17.8	$ 3.86~~3.56~~		$ 1.08~~1.00~~
50.1	to	60.0	Watts	21.3	$ ~~4.27~~4.62		$ 1.29~~1.20~~
60.1	to	70.0	Watts	24.9	$ 5.40~~4.99~~		$ 1.51~~1.40~~
70.1	to	80.0	Watts	28.4	$ 6.15~~5.70~~		$ 1.72~~1.60~~
80.1	to	90.0	Watts	32.0	$ ~~6.41~~6.93		$ 1.94~~1.80~~
90.1	to	100.0	Watts	35.6	$ 7.71~~7.12~~		$ 2.16~~2.00~~
100.1	to	110.0	Watts	39.1	$ 8.47~~7.84~~		$ 2.37~~2.20~~
110.1	to	120.0	Watts	42.7	$ 9.25~~8.55~~	~~(4)~~	$ 2.59~~2.40~~
120.1	to	130.0	Watts	46.2	$ 10.01~~9.26~~		$ 2.80~~2.60~~
130.1	to	140.0	Watts	49.8	$ 10.79~~9.97~~		$ 3.02~~2.80~~

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140.1	to	150.0	Watts	53.3	$ 11.55~~10.68~~		$ 3.23~~3.00~~
150.1	to	160.0	Watts	56.9	$ 12.33~~11.40~~		$ 3.45~~3.20~~
160.1	to	170.0	Watts	60.4	$ 13.09~~12.11~~		$ 3.66~~3.40~~
170.1	to	180.0	Watts	64.0	$ 13.87~~12.82~~		$ 3.88~~3.60~~
180.1	to	190.0	Watts	67.5	$ 14.63~~13.53~~		$ 4.09~~3.79~~
190.1	to	200.0	Watts	71.1	$ 15.41~~14.25~~		$ 4.31~~3.99~~
200.1	to	210.0	Watts	74.7	$ 16.19~~14.96~~		$ 4.53~~4.19~~
210.1	to	220.0	Watts	78.2	$ 16.95~~15.67~~		$ 4.74~~4.39~~
220.1	to	230.0	Watts	81.8	$ 17.73~~16.38~~		$ 4.96~~4.59~~
230.1	to	240.0	Watts	85.3	$ 18.48~~17.10~~		$ 5.17~~4.79~~
240.1	to	250.0	Watts	88.9	$ 19.26~~17.81~~		$ 5.39~~4.99~~
250.1	to	260.0	Watts	92.4	$ 20.02~~18.52~~	~~(5)~~	$ 5.60~~5.19~~
260.1	to	270.0	Watts	96.0	$ 20.80~~19.23~~		$ 5.82~~5.39~~
270.1	to	280.0	Watts	99.5	$ 21.56~~19.94~~		$ 6.03~~5.59~~
280.1	to	290.0	Watts	103.1	$ 22.34~~20.66~~		$ 6.25~~5.79~~
290.1	to	300.0	Watts	106.7	$ 23.12~~21.37~~		$ 6.47~~5.99~~
300.1	to	310.0	Watts	110.2	$ 23.88~~22.08~~		$ 6.68~~6.19~~
310.1	to	320.0	Watts	113.8	$ 24.66~~22.79~~		$ 6.90~~6.39~~
320.1	to	330.0	Watts	117.3	$ 25.42~~23.51~~		$ 7.11~~6.59~~
330.1	to	340.0	Watts	120.9	$ 26.20~~24.22~~		$ 7.33~~6.79~~
340.1	to	350.0	Watts	124.4	$ 29.96~~24.93~~		$ 7.54~~6.99~~
350.1	to	360.0	Watts	128.0	$ 27.74~~25.64~~		$ 7.76~~7.19~~
360.1	to	370.0	Watts	131.5	$ 28.50~~26.36~~		$ 7.97~~7.39~~
370.1	to	380.0	Watts	135.1	$ 29.28~~27.07~~		$ 8.19~~7.59~~
380.1	to	390.0	Watts	138.6	$ 30.03~~27.78~~		$ 8.40~~7.79~~
390.1	to	400.0	Watts	142.2	$ 30.81~~28.49~~		$ 8.62~~7.99~~

(1) Monthly kWh usage = Maximum Wattage in range x 355.5 hours per month / 1,000 Watts per kW.

(2) For lights larger than 400W, the applicable usage and rate shall be the sum of the 390.1 - 400.0 Watts row in the table above plus a wattage range such that the resulting range encompasses the actual wattage of the light (Example: for a 600 Watt light, the applicable usage and charge is determined by adding the 390.1 – 400.0 Watts row and the 190.1 – 200.0 Watts row together, resulting in a 590.1 – 600.0 Watt Range with a monthly usage of 213.300 kWh.).

~~(3) This Company owned LED Light is a 39W LED Streetlight, which is an operational substitute~~

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~~for the existing 175W MV, 55W LPS, 70W HPS and 100W HPS fixtures.~~

~~(4) This Company owned LED Light is a 118W LED Streetlight, which is an operational substitute for the existing 400W MV, 135W LPS, 200W HPS and 250W HPS fixtures.~~

~~(5) This Company owned LED Light is a 257W LED Streetlight, which is an operational substitute for a 400W HPS fixture.~~

C.1 CUSTOMER OWNED AND MAINTAINED METERED LIGHTING: For Customer-owned metered lights (excluding B above) where maintenance is not provided by the Company and is not included in the monthly charge:

Description	Monthly Rates (Customer Owned)
Metered Lighting	$ 0.~~0561839~~ 0606127

D. POLE CHARGE: For company owned lighting attached to a dedicated street lighting pole.

Description	Monthly Charge (Company Owned)
Wood Pole	$ ~~4.86~~5.99
Non-Wood Pole	$ 11.62~~9.45~~

E. FUEL AND PURCHASED POWER COST ADJUSTMENT: All kWh usage under this tariff will be subject to the Fuel and Purchase Power Cost Adjustment Clause ("FPPCAC") factors calculated according to the provisions in PNM's Rider 23.

The appropriate FPPCAC factors will be applied to all kWh appearing on bills rendered under this tariff.

F. OTHER APPLICABLE RIDERS: Any other PNM riders that may apply to this tariff shall be billed in accordance with the terms of those riders.

G. SPECIAL TAX AND ASSESSMENT ADJUSTMENT: Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and

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federal income taxes) payable by the utility and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

SPECIAL CONDITIONS:

I. Installation and Ownership of Lighting Facilities:

a) Company Owned Lighting Facilities-
Upon request from the Customer, the Company shall convert or install Company owned streetlighting fixtures at its own expense up to the limits provided by the Installation Allowance Table below, with any remaining expenses being the responsibility of the Customer. All lighting facilities shall be and remain the property of the Company.

Company Owned Light & Pole Installation Allowances

High Pressure Sodium Lighting Facilities	
70W High Pressure Sodium Street Light	$ ~~920.00~~880.00
100W High Pressure Sodium Street Light	$ ~~920.00~~900.00
200W High Pressure Sodium Street Light	$ ~~880.00~~830.00
250W High Pressure Sodium Street Light	$ 980.00
400W High Pressure Sodium Flood Light	$ 980.00
400W High Pressure Sodium Street Light	$ 980.00
Light Emitting Diode ("LED") Lighting Facilities	
~~39W LED Street Light~~Operational Substitute No. 1	$ ~~160.00~~179.81
~~118W LED Street Light~~Operational Substitute No. 2	$ ~~480.00~~630.58
~~257W LED Street Light~~Operational Substitute No. 3	$ ~~1,040.00~~1170.00
Dedicated Streetlight Poles	
Wood Pole	$ ~~520.00~~ 490.00
Non-Wood Pole	$ ~~1,010.00~~950.00

b) Customer Owned Lighting Facilities-
   i. The Customer shall be obligated to install its own streetlighting fixtures and poles at

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its own expense. The Company shall inspect and approve all Customer installed streetlighting prior to it being placed under this Rate.

ii. If requested by the Customer, poles or fixtures may be installed by the Company or an agent approved by the Company. Customer shall pay the Company for all installation costs of the facilities where such installation is done by the Company or the Company's agent.

iii. All facilities installed to provide electric service to customer owned streetlights under this tariff shall be and remain the property of the Company.

iv. The Customer is required to provide specific performance data on the total energy consumption of each non-standard fixture installed.

II. Highway Signs:

No service to or maintenance of highway signs connected to the lighting system is included under this schedule.

III. Changes and Additions:

Relocations, conversions and changes, other than normal operation and maintenance of any luminaries, poles, or fixtures after the same have been installed, including system replacements or knock-down replacements, will be at the expense of the customer. If requested by the customer, Company agrees to make all replacements for knock-downs of Customer owned light poles and to bill the Customer for all costs associated with such replacements. Customer agrees to coordinate recovery efforts with Company in instances where Company has potential legal liability from claims of the parties responsible for Customer owned pole damage. The Company will attempt to recover the costs of knock-down replacements of Company owned light poles from the parties responsible. Any unrecoverable costs will be billed to the customer. The Company will furnish to the customer a copy of all information pertaining to the identity and circumstances of the knock-down when same becomes available to the Company.

IV. Operation and Maintenance:

A. Total Company-Owned System:
The Company will perform normal operation and maintenance of the lighting system which includes routine maintenance, repairs and fixture servicing including all spot lamp replacement required by faulty lamps.

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Major repair and fixture replacements required due to vandalism, vehicle accidents, projectiles, or acts of God will be performed by the Company at the expense of the customer.

Mandatory replacement of or alterations to working luminaire to bring them into compliance with existing or future laws or ordinances will be performed by the Company at the expense of the customer.

It shall be the duty of the customer to report to the Company the failure of any lamp covered by the Rate to burn, or to burn adequately, and it shall thereafter be the obligation of the Company to at once restore such lamp to service subject, however, to the provisions of Special Conditions I, above and to subsequent provisions of this item as to replacements. Any lamp so reported as failing to burn, or to burn adequately, shall be replaced or repaired and returned to regular operation within seventy-two (72) hours from the time of notice of such failure to the Company. Pole hits and failures due to the loss of underground conductors or control equipment are excluded from the 72 hour requirement and shall be repaired as material availability and scheduling permits.

B. Total Customer-Owned System:

Page 1; Section A - "Light Charge (for unmetered lights where maintenance is provided by the Company and included in the Monthly Change": Maintenance under this section includes faulty photoelectric cell replacement, faulty lamp replacement, faulty fixture fuse replacement, and incidental lens cleaning.

Page 2; Sections B - "Metered Series Street Lighting", and C - "Customer Owned and Maintained Lighting". Maintenance under these sections is the responsibility of the customer.

All other operation and maintenance, including traffic control costs and troubleshooting customer owned systems may be done by the Company at the request and expense of the customer. The Company will not stock maintenance items that are considered nonstandard by the Company for use in maintaining customer-owned lighting systems. Stocking of these nonstandard items is the sole responsibility of the customer.

V. Termination:

Service to any lamp installed hereunder shall be terminated by the Company upon receipt of thirty (30) days notice and coincident with such notice, payment of the Company's depreciated investment for any lamp and/or pole associated with the removal of any Company owned lighting facilities.

VI. In the event of a conflict between the terms of this rate schedule and any provision contained in the

Advice Notice No. 533~~529~~

Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

16~~5~~TH REVISED RATE NO. 20
CANCELING 15~~4~~TH REVISED RATE NO. 20

INTEGRATED SYSTEM STREETLIGHTING
AND FLOODLIGHTING SERVICE

streetlighting contract in effect, the relevant terms of the rate schedule shall control.

Advice Notice No. 533~~529~~

Gerard T. Ortiz
Vice President, PNM Regulatory Affairs

Proposed Illustrative Rates for Phase I

PNM Exhibit JCA-16

Is contained in the following 15 pages

Schedule: *1A/1B* *Residential Service*

Source: SC-5

Embedded Cost Component

Line No.	(A)	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Banded Revenue (Inc. FPPCAC)	(E) Rates at Banded Revenue	(F)	(G) 1A Billing Units (Test Year)	(H) 1A Proposed Rates	(I) 1A Proposed Revenue	(J) 1B Billing Units (Test Year)	(K) 1B Proposed Rates	(L) 1B Proposed Revenue	(M) Total Proposed Revenue
									$ 358,142,658			$ 380,040	$ 358,522,698
1	*Customer Components*	5,615,569						$ 10.39	$ 58,330,677		$ 26.10	$ 37,897	$ 58,368,574
2	*Summer*	1,437,857					*Summer*			*Summer*			
3	Customer Services (per customer/per month)					Customer	1,437,485	$ 10.39	$ 14,935,473	372	$ 20.81	$ 7,731	$ 14,943,204
4	Customer Meter (per customer/per month)					Meter				372	$ 5.29	$ 1,965	$ 1,965
5	Customer Meter Reading (per customer/per month)												
6	Customer Billing and Collection (per customer/per month)												
7	Customer Service and Information (per customer/per month)												
8	Customer Other (per customer/per month)												
9													
10	*Non-Summer*	4,177,712					*Non-Summer*			*Non-Summer*			
11	Customer Services (per customer/per month)					Customer	4,176,632	$ 10.39	$ 43,395,204	1,080	$ 20.81	$ 22,485	$ 43,417,689
12	Customer Meter (per customer/per month)					Meter				1,080	$ 5.29	$ 5,716	$ 5,716
13	Customer Meter Reading (per customer/per month)												
14	Customer Billing and Collection (per customer/per month)												
15	Customer Service and Information (per customer/per month)												
16	Customer Other (per customer/per month)												
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*							$ -	$ -		$ -	$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			*Summer*			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	*Non-Summer (Billable Demand)*						*Non-Summer*			*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	3,164,862,106							$ 299,811,981			$ 342,143	$ 300,154,124
34													
35	Energy Fuel (kWh)												
36	Energy Non-Fuel (kWh)												
37													
38	Block 1 Summer (1A)	520,245,451					520,245,451	$ 0.0813898	$ 42,342,674				
39	Block 2 Summer (1A)	255,399,661					255,399,661	$ 0.1193477	$ 30,481,371				
40	Block 3 Summer (1A)	169,309,364					169,309,364	$ 0.1366890	$ 23,142,724				
41	Block 1 Non- Summer (1A)	1,429,514,856					1,429,514,856	$ 0.0813898	$ 116,347,931				
42	Block 2 Non- Summer (1A)	522,833,656					522,833,656	$ 0.1081296	$ 56,533,778				
43	Block 3 Non- Summer (1A)	263,929,600					263,929,600	$ 0.1173173	$ 30,963,502				
44	Summer On-Peak (1B)	271,123								271,123	$ 0.1892176	$ 51,301	$ 51,301
45	Summer Off-Peak (1B)	430,893								430,893	$ 0.0607866	$ 26,193	$ 26,193
46	Non-Summer On-Peak (1B)	1,001,957								1,001,957	$ 0.1473140	$ 147,602	$ 147,602
47	Non-Summer Off-Peak (1B)	1,925,545								1,925,545	$ 0.0607866	$ 117,047	$ 117,047
48													
49													
50	Total		$ -	$ -					$ 358,142,658			$ 380,040.45	$ 358,522,698
									$ 0.113292			$ 0.104708	
									99.894%			0.1060%	$ (0)

PNM EXHIBIT JCA-16

Schedule: 2A/2B **Small Power Service**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Source:	SC-5							$ 102,626,279			$ 1,533,328	$ 104,159,607
	Embedded Cost Component						2A			2B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	633,896						$ 17.31	$ 10,789,943		$ 17.31	$ 181,949	$ 10,971,892
2	*Summer*	162,294					*Summer*			*Summer*			
3	Customer Services (per customer/per month)					Customer	159,605	$ 17.31	$ 2,762,545	2,690	$ 9.52	$ 25,601	$ 2,788,145
4	Customer Meter (per customer/per month)					Meter				2,690	$ 7.79	$ 20,953	$ 20,953
5	Customer Meter Reading (per customer/per month)												
6	Customer Billing and Collection (per customer/per month)												
7	Customer Service and Information (per customer/per month)												
8	Customer Other (per customer/per month)												
9													
10	*Non-Summer*	471,602					*Non-Summer*			*Non-Summer*			
11	Customer Services (per customer/per month)					Customer	463,779	$ 17.31	$ 8,027,398	7,822	$ 9.52	$ 74,456	$ 8,101,855
12	Customer Meter (per customer/per month)					Meter				7,822	$ 7.79	$ 60,939	$ 60,939
13	Customer Meter Reading (per customer/per month)												
14	Customer Billing and Collection (per customer/per month)												
15	Customer Service and Information (per customer/per month)												
16	Customer Other (per customer/per month)												
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*							$ -	$ -		$ -	$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			*Summer*			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	*Non-Summer (Billable Demand)*						*Non-Summer*			*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	915,396,792							$ 91,836,336			$ 1,351,380	$ 93,187,715
34													
35	Energy Fuel (kWh)												
36	Energy Non-Fuel (kWh)												
37													
38	Summer (2A)	266,128,782					266,128,782	$ 0.1188257	$ 31,622,934				
39	Non-Summer (2A)	636,224,067					636,224,067	$ 0.0946418	$ 60,213,401				
40	Summer On-Peak (2B)	1,389,221								1,389,221	$ 0.2118342	$ 294,285	$ 294,285
41	Summer Off-Peak (2B)	2,338,040								2,338,040	$ 0.0609958	$ 142,611	$ 142,611
42	Non-Summer On-Peak (2B)	3,352,248								3,352,248	$ 0.1642715	$ 550,679	$ 550,679
43	Non-Summer Off-Peak (2B)	5,964,439								5,964,439	$ 0.0609958	$ 363,806	$ 363,806
44													
45	Total		$ -	$ -					$ 102,626,279			$ 1,533,328	$ 104,159,607
									98.528%			1.472%	

PNM EXHIBIT JCA-16

Schedule: 3B — **General Power Service**

Source: SC-5

$ 130,818,621

Embedded Cost Component

Line No.	(A)	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Rates at Cost Based Revenue	(E) Banded Revenue	(F) Rates at Banded Revenue	(G)	(H) 3B Billing Units (Test Year)*	(I) Proposed Rates	(J) Proposed Revenue	(K) Total Proposed Revenue
1	Customer Components	40,601							$ 79.13	$ 3,212,773	$ 3,212,773
2	Summer	10,452						Summer			
3	Customer Services (per customer/per month)						Pri.	251	$ 79.13	$ 19,895	$ 19,895
4	Customer Meter (per customer/per month)						Sec.	10,201	$ 79.13	$ 807,192	$ 807,192
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	Non-Summer	30,149						Non-Summer			
11	Customer Services (per customer/per month)						Pri.	721	$ 79.13	$ 57,016	$ 57,016
12	Customer Meter (per customer/per month)						Sec.	29,428	$ 79.13	$ 2,328,669	$ 2,328,669
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
18	Demand Components	4,157,499							$ 23.65	$ 98,331,803	$ 98,331,803
19	Summer (Billable Demand)	1,184,705						Summer			
20	Demand Production (Summer kW-Month)	37.84%					Pri.	65,402	$ 27.71	$ 1,812,581	$ 1,812,581
21	Demand Transmission (Summer kW-Month)	28.50%					Sec.	1,119,302	$ 28.02	$ 31,367,656	$ 31,367,656
22	Demand Substation (Summer kW-Month)	28.50%									
23	Demand Distribution Primary (Summer kW-Month)	28.50%									
24	Demand Distribution Secondary (Summer kW-Month)	28.50%									
25											
26	Non-Summer (Billable Demand)	2,972,794						Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%					Pri.	181,145	$ 21.62	$ 3,917,026	$ 3,917,026
28	Demand Transmission (Non-Summer kW-Month)	71.50%					Sec.	2,791,650	$ 21.93	$ 61,234,540	$ 61,234,540
29	Demand Substation (Non-Summer kW-Month)	71.50%									
30	Demand Distribution Primary (Non-Summer kW-Month)	71.50%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	71.50%									
32								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
33	Energy Components	1,641,925,784								$ 29,244,896	$ 29,244,896
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37								1,641,925,784			
38	Summer On-Peak	206,012,909						206,012,909	$ 0.0278123	$ 5,729,701	$ 5,729,701
39	Summer Off-Peak	269,573,654						269,573,654	$ 0.0129482	$ 3,490,491	$ 3,490,491
40	Non-Summer On-Peak	487,783,611						487,783,611	$ 0.0230402	$ 11,238,636	$ 11,238,636
41	Non-Summer Off-Peak	678,555,610						678,555,610	$ 0.0129482	$ 8,786,068	$ 8,786,068
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 29,149					$ 29,149	$ 29,149
46											
47	Billable RkVA Summer	35,375			$ 9,551	$0.27		35,375	$ 0.27	$ 9,551	$ 9,551
48	Billable RkVA Non-Summer	72,582			$ 19,597	$0.27		72,582	$ 0.27	$ 19,597	$ 19,597
49	Rider 8 Discounts Summer (Sec.)	0			$ -	($6.85)		0	$0.00	$ -	$ -
50	Rider 8 Discounts Non-Summer (Sec.)	0			$ -	($0.33)		0	$0.00	$ -	$ -
51	Total		$ -		$ -					$ 130,818,621	$ 130,818,621
52											
53											$ 0

PNM EXHIBIT JCA-16

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Schedule:	***3C***			***General Power Service (Low Load Factor)***						
	Source:	*SC-5*									***$ 24,278,971***
	Embedded Cost Component								*3C*		
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	***Customer Components***	*11,113*							*$ 65.72*	*$ 730,340*	*$ 730,340*
2	***Summer***	**2,785**						***Summer***			
3	Customer Services (per customer/per month)						Pri.	55	*$ 65.72*	$ 3,632	$ 3,632
4	Customer Meter (per customer/per month)						Sec.	2,730	*$ 65.72*	$ 179,398	$ 179,398
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	***Non-Summer***	**8,328**						***Non-Summer***			
11	Customer Services (per customer/per month)						Pri.	157	*$ 65.72*	$ 10,336	$ 10,336
12	Customer Meter (per customer/per month)						Sec.	8,171	*$ 65.72*	$ 536,974	$ 536,974
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
18	***Demand Components***	*1,055,286*							*$ 8.57*	*$ 9,046,247*	*$ 9,046,247*
19	***Summer (Billable Demand)***	**298,925**						***Summer***			
20	Demand Production (Summer kW-Month)	**37.84%**					Pri.	14,734	*$ 9.97*	$ 146,939	$ 146,939
21	Demand Transmission (Summer kW-Month)	**28.33%**					Sec.	284,190	*$ 10.28*	$ 2,922,702	$ 2,922,702
22	Demand Substation (Summer kW-Month)	**28.33%**									
23	Demand Distribution Primary (Summer kW-Month)	**28.33%**									
24	Demand Distribution Secondary (Summer kW-Mont	**28.33%**									
25											
26	***Non-Summer (Billable Demand)***	**756,361**						***Non-Summer***			
27	Demand Production (Non-Summer kW-Month)	**62.16%**					Pri.	52,361	*$ 7.61*	$ 398,560	$ 398,560
28	Demand Transmission (Non-Summer kW-Month)	**71.67%**					Sec.	704,000	*$ 7.92*	$ 5,578,046	$ 5,578,046
29	Demand Substation (Non-Summer kW-Month)	**71.67%**									
30	Demand Distribution Primary (Non-Summer kW-Mo	**71.67%**									
31	Demand Distribution Secondary (Non-Summer kW-I	**71.67%**									
32								Billing Units (Test Year)*	Proposed Rates	Proposed Revenue	
33	***Energy Components***	*210,125,160*								*$ 14,486,853*	*$ 14,486,853*
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	29,517,721						29,517,721	*$ 0.1091061*	$ 3,220,563	$ 3,220,563
39	Summer Off-Peak	30,823,973						30,823,973	*$ 0.0491719*	$ 1,515,673	$ 1,515,673
40	Non-Summer On-Peak	72,248,221						72,248,221	*$ 0.0821897*	$ 5,938,063	$ 5,938,063
41	Non-Summer Off-Peak	77,535,244						77,535,244	*$ 0.0491719*	$ 3,812,554	$ 3,812,554
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (87,657)					$ (46,382)	$ (46,382)
46											
47	Billable RkVA Summer	15,157			$ 4,092	*$0.27*		15,157	*$ 0.27*	$ 4,092	$ 4,092
48	Billable RkVA Non-Summer	42,365			$ 11,438	*$0.27*		42,365	*$ 0.27*	$ 11,438	$ 11,438
49	Post-Rider 8 Discounts Summer (Sec.)	12,817			$ (87,793)	*($6.85)*		12,817	*($4.11)*	*($52,676)*	$ (52,676)
50	Post-Rider 8 Discounts Non-Summer (Sec.)	40,513			$ (15,395)	*($0.38)*		40,513	*($0.23)*	*($9,237)*	$ (9,237)
51	Total		$ -		$ -					***$ 24,217,058***	***$ 24,217,058***
52											
											$ (61,913)

PNM EXHIBIT JCA-16

Schedule: 4B — **Large Power Service**

Source: SC-5

$ 71,517,141

Embedded Cost Component

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		4B Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	2,724							$ 556.58	$ 1,516,116	$ 1,516,116
2	*Summer*	697						*Summer*			
3	Customer Services (per customer/per month)							411	$ 556.58	$ 228,625	$ 228,625
4	Customer Meter (per customer/per month)						PNMOw-S	286	$ 556.58	$ 159,291	$ 159,291
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	*Non-Summer*	2,027						*Non-Summer*			
11	Customer Services (per customer/per month)							1,205	$ 556.58	$ 670,698	$ 670,698
12	Customer Meter (per customer/per month)						PNMOw	822	$ 556.58	$ 457,502	$ 457,502
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	2,340,344							$ 22.39	$ 52,402,264	$ 52,402,264
19	*Summer (Billable Demand)*	626,741						*Summer*			
20	Demand Production (Summer kW-Month)	37.84%						435,274	$ 27.98	$ 12,177,758	$ 12,177,758
21	Demand Transmission (Summer kW-Month)	26.78%					PNMOw	191,467	$ 29.33	$ 5,615,781	$ 5,615,781
22	Demand Substation (Summer kW-Month)	26.78%									
23	Demand Distribution Primary (Summer kW-Month)	26.78%									
24	Demand Distribution Secondary (Summer kW-Month)	26.78%									
25											
26	*Non-Summer (Billable Demand)*	1,713,603						*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%						1,218,659	$ 19.81	$ 24,137,561	$ 24,137,561
28	Demand Transmission (Non-Summer kW-Month)	73.22%					PNMOw	494,943	$ 21.16	$ 10,471,163	$ 10,471,163
29	Demand Substation (Non-Summer kW-Month)	73.22%									
30	Demand Distribution Primary (Non-Summer kW-Month)	73.22%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	73.22%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	1,106,704,902								$ 17,540,448	$ 17,540,448
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	124,188,276						124,188,276	$ 0.0243958	$ 3,029,678	$ 3,029,678
39	Summer Off-Peak	183,049,039						183,049,039	$ 0.0126699	$ 2,319,221	$ 2,319,221
40	Non-Summer On-Peak	317,918,562						317,918,562	$ 0.0191569	$ 6,090,349	$ 6,090,349
41	Non-Summer Off-Peak	481,549,025						481,549,025	$ 0.0126699	$ 6,101,199	$ 6,101,199
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (55,768)					$ (10,135)	$ (10,135)
46											
47	Billable RkVA Summer	63,920			$ 17,258	$0.27		63,920	$0.27	$ 17,258	$ 17,258
48	Billable RkVA Non-Summer	152,054			$ 41,055	$0.27		152,054	$0.27	$ 41,055	$ 41,055
49	Post-Rider 8 Discounts Summer (Sub)	0			$0	($15.83)		0	($9.50)	$0	$ -
50	Post-Rider 8 Discounts Summer (Pri)	3,887			($61,530)	($15.83)		3,887	($9.50)	($36,918)	$ (36,918)
51	Post-Rider 8 Discounts Non-Summer (Sub)	0			$0	($7.38)		-	($4.43)	$0	$ -
52	Post-Rider 8 Discounts Non-Summer (Pri)	12,880			($52,551)	($4.08)		12,880	($2.45)	($31,530)	$ (31,530)
53											$ -
54											
55	Total		$ -		$ -					$ 71,448,693	$ 71,448,693
56											

$ (68,448)

Schedule: 5B — *Large Service for Customers >= 8,000 kW*

Source: SC-5

$ 4,202,514

Embedded Cost Component

Line No.	(A)	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Rates at Cost Based Revenue	(E) Banded Revenue	(F) Rates at Banded Revenue	(G)	(H) 5B Billing Units (Test Year)	(I) Proposed Rates	(J) Proposed Revenue	(K) Total Proposed Revenue
1	Customer Components	24							$ 2,359.17	$ 56,620	$ 56,620
2	*Summer*	6						*Summer*			
3	Customer Services (per customer/per month)							6	$ 2,359.17	$ 14,487	$ 14,487
4	Customer Meter (per customer/per month)										$ -
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	*Non-Summer*	18						*Non-Summer*			
11	Customer Services (per customer/per month)							18	$ 2,359.17	$ 42,133	$ 42,133
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	192,000							$ 16.23	$ 3,115,473	$ 3,115,473
19	*Summer (Billable Demand)*	49,125						*Summer*			
20	Demand Production (Summer kW-Month)	37.84%						49,125	$ 22.28	$ 1,094,658	$ 1,094,658
21	Demand Transmission (Summer kW-Month)	25.59%									$ -
22	Demand Substation (Summer kW-Month)	25.59%									
23	Demand Distribution Primary (Summer kW-Month)	25.59%									
24	Demand Distribution Secondary (Summer kW-Month)	25.59%									
25											
26	*Non-Summer (Billable Demand)*	142,875						*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%						142,875	$ 14.14	$ 2,020,815	$ 2,020,815
28	Demand Transmission (Non-Summer kW-Month)	74.41%									$ -
29	Demand Substation (Non-Summer kW-Month)	74.41%									
30	Demand Distribution Primary (Non-Summer kW-Month)	74.41%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	74.41%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	70,596,567								$ 1,023,267	$ 1,023,267
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	7,245,481						7,245,481	$ 0.0252205	$ 182,735	$ 182,735
39	Summer Off-Peak	11,600,913						11,600,913	$ 0.0111763	$ 129,656	$ 129,656
40	Non-Summer On-Peak	19,415,531						19,415,531	$ 0.0180007	$ 349,493	$ 349,493
41	Non-Summer Off-Peak	32,334,642						32,334,642	$ 0.0111763	$ 361,383	$ 361,383
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 7,154					$ 7,154	$ 7,154
46											
47	Billable RkVA Summer	4,992			$ 1,348	$0.27		4,992	$0.27	$ 1,348	$ 1,348
48	Billable RkVA Non-Summer	21,503			$ 5,806	$0.27		21,503	$0.27	$ 5,806	$ 5,806
49											$ -
50											$ -
51											$ -
52											$ -
53	Total		$ -		$ -					$ 4,202,514	$ 4,202,514
											$ 0

PNM EXHIBIT JCA-16

Schedule: 10A/10B Irrigation Service

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Source:	SC-5							$ 338,817			$ 1,602,534	$ 1,941,351
	Embedded Cost Component						10A			10B			
Line No.		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	4,010						$ 17.09	$ 24,423		$ 17.09	$ 44,113	$ 68,536
2	Summer	1,027					Summer			Summer			
3	Customer Services (per customer/per month)					Customer	366	$ 17.09	$ 6,259	661	$ 11.72	$ 7,745	$ 14,004
4	Customer Meter (per customer/per month)					Meter				661	$ 5.37	$ 3,552	$ 3,552
5	Customer Meter Reading (per customer/per month)												
6	Customer Billing and Collection (per customer/per month)												
7	Customer Service and Information (per customer/per month)												
8	Customer Other (per customer/per month)												
9													
10	Non-Summer	2,983					Non-Summer			Non-Summer			
11	Customer Services (per customer/per month)					Customer	1,063	$ 17.09	$ 18,164	1,920	$ 11.72	$ 22,498	$ 40,662
12	Customer Meter (per customer/per month)					Meter				1,920	$ 5.37	$ 10,319	$ 10,319
13	Customer Meter Reading (per customer/per month)												
14	Customer Billing and Collection (per customer/per month)												
15	Customer Service and Information (per customer/per month)												
16	Customer Other (per customer/per month)												
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components								$ -			$ -	$ -
19	Summer (Billable Demand)						Summer			Summer			
20	Demand Production (Summer kW-Month)								$ -			$ -	$ -
21	Demand Transmission (Summer kW-Month)												$ -
22	Demand Substation (Summer kW-Month)												
23	Demand Distribution Primary (Summer kW-Month)												
24	Demand Distribution Secondary (Summer kW-Month)												
25													
26	Non-Summer (Billable Demand)						Non-Summer			Non-Summer			
27	Demand Production (Non-Summer kW-Month)								$ -			$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)												$ -
29	Demand Substation (Non-Summer kW-Month)												
30	Demand Distribution Primary (Non-Summer kW-Month)												
31	Demand Distribution Secondary (Non-Summer kW-Month)												
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	23,427,777							$ 314,394			$ 1,558,421	$ 1,872,814
34													
35	Energy Fuel (kWh)												
36	Energy Non-Fuel (kWh)												
37							3,997,323						
38	Summer (10A)	1,696,099					1,696,099	$ 0.0828811	$ 140,574				
39	Non-Summer (10A)	2,301,224				9.7%	2,301,224	$ 0.0755334	$ 173,819	19,430,454			
40	Summer On-Peak (10B)	2,900,445								2,900,445	$ 0.1274226	$ 369,582	$ 369,582
41	Summer Off-Peak (10B)	5,199,480								5,199,480	$ 0.0580308	$ 301,730	$ 301,730
42	Non-Summer On-Peak (10B)	3,917,891								3,917,891	$ 0.1166310	$ 456,948	$ 456,948
43	Non-Summer Off-Peak (10B)	7,412,637								7,412,637	$ 0.0580308	$ 430,161	$ 430,161
44													
45	Total		$ -	$ -					$ 338,817			$ 1,602,534	$ 1,941,351
46									17.45%			82.55%	
													$ -

PNM EXHIBIT JCA-16

Schedule: 11B — **Water and Sewage Pumping Service**

Source: SC-5

$ 9,027,233

Line No.	(A) Embedded Cost Component	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Banded Revenue	(E) Rates at Banded Revenue	(F)	(G) 11B Billing Units (Test Year)	(H) Proposed Rates	(I) Proposed Revenue	(J) Total Proposed Revenue
1	Customer Components	1,968						$ 304.93	$ 600,102	$ 600,102
2	*Summer*	504					*Summer*			
3	Customer Services (per customer/per month)						504	$ 304.93	$ 153,543	$ 153,543
4	Customer Meter (per customer/per month)									$ -
5	Customer Meter Reading (per customer/per month)									
6	Customer Billing and Collection (per customer/per month)									
7	Customer Service and Information (per customer/per month)									
8	Customer Other (per customer/per month)									
9										
10	*Non-Summer*	1,464					*Non-Summer*			
11	Customer Services (per customer/per month)						1,464	$ 304.93	$ 446,559	$ 446,559
12	Customer Meter (per customer/per month)									$ -
13	Customer Meter Reading (per customer/per month)									
14	Customer Billing and Collection (per customer/per month)									
15	Customer Service and Information (per customer/per month)									
16	Customer Other (per customer/per month)									
17							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components								$ -	$ -
19	*Summer (Billable Demand)*						*Summer*			
20	Demand Production (Summer kW-Month)								$ -	$ -
21	Demand Transmission (Summer kW-Month)									$ -
22	Demand Substation (Summer kW-Month)									
23	Demand Distribution Primary (Summer kW-Month)									
24	Demand Distribution Secondary (Summer kW-Month)									
25										
26	*Non-Summer (Billable Demand)*						*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)								$ -	$ -
28	Demand Transmission (Non-Summer kW-Month)									$ -
29	Demand Substation (Non-Summer kW-Month)									
30	Demand Distribution Primary (Non-Summer kW-Month)									
31	Demand Distribution Secondary (Non-Summer kW-Month)									
32							Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	168,508,457							$ 8,427,130	$ 8,427,130
34										
35	Energy Fuel (kWh)									
36	Energy Non-Fuel (kWh)									
37										
38	Summer On-Peak	12,600,011					12,600,011	$ 0.1533329	$ 1,931,996	$ 1,931,996
39	Summer Off-Peak	40,775,401					40,775,401	$ 0.0296015	$ 1,207,011	$ 1,207,011
40	Non-Summer On-Peak	27,170,788					27,170,788	$ 0.0987941	$ 2,684,312	$ 2,684,312
41	Non-Summer Off-Peak	87,962,256					87,962,256	$ 0.0296015	$ 2,603,811	$ 2,603,811
42										
43										
44		Billing Units (Test Year)		Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits			$ -					$ -	$ -
46										
47										$ -
48										$ -
49										$ -
50	Total		$ -	$ -					$ 9,027,233	$ 9,027,233
										$ -

PNM EXHIBIT JCA-16

Schedule: 15B **Large Service for Public Universities**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		Source: SC-5									$ 4,035,344
	Embedded Cost Component							15B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	12							$ 4,181.15	$ 50,174	$ 50,174
2	Summer	3						Summer			
3	Customer Services (per customer/per month)							3	$ 4,181.15	$ 12,543	$ 12,543
4	Customer Meter (per customer/per month)										$ -
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	Non-Summer	9						Non-Summer			
11	Customer Services (per customer/per month)							9	$ 4,181.15	$ 37,630	$ 37,630
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	202,478							$ 14.49	$ 2,933,247	$ 2,933,247
19	Summer (Billable Demand)	56,320						Summer			
20	Demand Production (Summer kW-Month)	37.84%						56,320	$ 18.89	$ 1,063,644	$ 1,063,644
21	Demand Transmission (Summer kW-Month)	27.82%									$ -
22	Demand Substation (Summer kW-Month)	27.82%									
23	Demand Distribution Primary (Summer kW-Month)	27.82%									
24	Demand Distribution Secondary (Summer kW-Month)	27.82%									
25											
26	Non-Summer (Billable Demand)	146,158						Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%						146,158	$ 12.79	$ 1,869,604	$ 1,869,604
28	Demand Transmission (Non-Summer kW-Month)	72.18%									$ -
29	Demand Substation (Non-Summer kW-Month)	72.18%									
30	Demand Distribution Primary (Non-Summer kW-Month)	72.18%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.18%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	63,683,882								$ 1,001,361	$ 1,001,361
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	8,298,219						8,298,219	$ 0.0272258	$ 225,925	$ 225,925
39	Summer Off-Peak	12,620,849						12,620,849	$ 0.0108689	$ 137,175	$ 137,175
40	Non-Summer On-Peak	16,661,882						16,661,882	$ 0.0212791	$ 354,550	$ 354,550
41	Non-Summer Off-Peak	26,102,931						26,102,931	$ 0.0108689	$ 283,711	$ 283,711
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 50,561					$ 50,561	$ 50,561
46											
47	Contract Facility Charge Summer	16,801			$ 12,937	$0.77		16,801	$ 0.77	$ 12,937	$ 12,937
48	Contract Facility Charge Non-Summer	48,863			$ 37,625	$0.77		48,863	$ 0.77	$ 37,625	$ 37,625
49	Billable RkVA Summer	0			$ -	$0.27		0	$0.27	$ -	$ -
50	Billable RkVA Non-Summer	0			$ -	$0.27		0	$0.27	$ -	$ -
51											$ -
52											$ -
53	Total		$ -		$ -					$ 4,035,344	$ 4,035,344
											$ 0

PNM EXHIBIT JCA-16

Schedule: 30B — **Large Service for Manufacturing**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5									$ 15,083,929
	Embedded Cost Component							30B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	*Customer Components*	12							$ 21,210.36	$ 254,524	$ 254,524
2	*Summer*	3						*Summer*			
3	Customer Services (per customer/per month)							3	$ 21,210.36	$ 63,631	$ 63,631
4	Customer Meter (per customer/per month)										
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	*Non-Summer*	9						*Non-Summer*			
11	Customer Services (per customer/per month)							9	$ 21,210.36	$ 190,893	$ 190,893
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*	502,944							$ 24.28	$ 12,212,617	$ 12,212,617
19	*Summer (Billable Demand)*	128,684						*Summer*			
20	Demand Production (Summer kW-Month)	37.84%						128,684	$ 31.96	$ 4,112,123	$ 4,112,123
21	Demand Transmission (Summer kW-Month)	25.59%									$ -
22	Demand Substation (Summer kW-Month)	25.59%									
23	Demand Distribution Primary (Summer kW-Month)	25.59%									
24	Demand Distribution Secondary (Summer kW-Month)	25.59%									
25											
26	*Non-Summer (Billable Demand)*	374,260						*Non-Summer*			
27	Demand Production (Non-Summer kW-Month)	62.16%						374,260	$ 21.64	$ 8,100,494	$ 8,100,494
28	Demand Transmission (Non-Summer kW-Month)	74.41%									$ -
29	Demand Substation (Non-Summer kW-Month)	74.41%									
30	Demand Distribution Primary (Non-Summer kW-Month)	74.41%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	74.41%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	363,666,494								$ 2,604,399	$ 2,604,399
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	33,295,199						33,295,199	$ 0.0117134	$ 389,998	$ 389,998
39	Summer Off-Peak	59,708,151						59,708,151	$ 0.0057150	$ 341,229	$ 341,229
40	Non-Summer On-Peak	96,897,406						96,897,406	$ 0.0090829	$ 880,109	$ 880,109
41	Non-Summer Off-Peak	173,765,738						173,765,738	$ 0.0057150	$ 993,063	$ 993,063
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 12,389					$ 12,389	$ 12,389
46											
47	Billable RkVA Summer	11,892			$ 3,211	$0.27		11,892	$0.27	$ 3,211	$ 3,211
48	Billable RkVA Non-Summer	33,993			$ 9,178	$0.27		33,993	$0.27	$ 9,178	$ 9,178
49											$ -
50											$ -
51											$ -
52											$ -
53	Total		$ -		$ -					$ 15,083,929	$ 15,083,929
											$ 0

Schedule: 33B — **Large Service for Station Power**

Source: SC-5

$ 184,686

Embedded Cost Component

Line No.	(A)	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Rates at Cost Based Revenue	(E) Banded Revenue	(F) Rates at Banded Revenue	(G)	(H) 33B Billing Units (Test Year)	(I) Proposed Rates	(J) Proposed Revenue	(K) Total Proposed Revenue
1	Customer Components	12							$ 424.59	$ 5,095	$ 5,095
2	Summer	3						Summer			
3	Customer Services (per customer/per month)							3	$ 424.59	$ 1,274	$ 1,274
4	Customer Meter (per customer/per month)										$ -
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	Non-Summer	9						Non-Summer			
11	Customer Services (per customer/per month)							9	$ 424.59	$ 3,821	$ 3,821
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	21,021							$ 5.25	$ 110,282	$ 110,282
19	Summer (Billable Demand)	5,495						Summer			
20	Demand Production (Summer kW-Month)	37.84%						5,495	$ 7.20	$ 39,566	$ 39,566
21	Demand Transmission (Summer kW-Month)	26.14%									$ -
22	Demand Substation (Summer kW-Month)	26.14%									
23	Demand Distribution Primary (Summer kW-Month)	26.14%									
24	Demand Distribution Secondary (Summer kW-Month)	26.14%									
25											
26	Non-Summer (Billable Demand)	15,526						Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%						15,526	$ 4.55	$ 70,715	$ 70,715
28	Demand Transmission (Non-Summer kW-Month)	73.86%									$ -
29	Demand Substation (Non-Summer kW-Month)	73.86%									
30	Demand Distribution Primary (Non-Summer kW-Month)	73.86%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	73.86%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	3,354,394								$ 35,659	$ 35,659
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	280,644						280,644	$ 0.0170030	$ 4,772	$ 4,772
39	Summer Off-Peak	581,919						581,919	$ 0.0084253	$ 4,903	$ 4,903
40	Non-Summer On-Peak	914,064						914,064	$ 0.0138845	$ 12,691	$ 12,691
41	Non-Summer Off-Peak	1,577,767						1,577,767	$ 0.0084253	$ 13,293	$ 13,293
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ 33,650					$ 33,650	$ 33,650
46											
47	Billable RkVA Summer	6,014			$ 1,624	$0.27		6,014	$0.27	$ 1,624	$ 1,624
48	Billable RkVA Non-Summer	118,615			$ 32,026	$0.27		118,615	$0.27	$ 32,026	$ 32,026
49	Total		$ -		$ -					$ 184,686	$ 184,686
50											

$ 0

PNM EXHIBIT JCA-16

Schedule: 35B — **Large Power Service >=3,000 kW**

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Source:	SC-5									$ 7,134,600
	Embedded Cost Component							35B			
		Billing Units (Test Year)	Cost Based Revenue (ECCOSS)	Rates at Cost Based Revenue	Banded Revenue	Rates at Banded Revenue		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	Total Proposed Revenue
1	Customer Components	48							$ 3,130.61	$ 150,269	$ 150,269
2	Summer	12						Summer			
3	Customer Services (per customer/per month)							12	$ 3,130.61	$ 37,567	$ 37,567
4	Customer Meter (per customer/per month)										$ -
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	Non-Summer	36						Non-Summer			
11	Customer Services (per customer/per month)							36	$ 3,130.61	$ 112,702	$ 112,702
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	Demand Components	305,369							$ 19.38	$ 5,918,874	$ 5,918,874
19	Summer (Billable Demand)	83,120						Summer			
20	Demand Production (Summer kW-Month)	37.84%						83,120	$ 25.39	$ 2,110,707	$ 2,110,707
21	Demand Transmission (Summer kW-Month)	27.22%									$ -
22	Demand Substation (Summer kW-Month)	27.22%									
23	Demand Distribution Primary (Summer kW-Month)	27.22%									
24	Demand Distribution Secondary (Summer kW-Month)	27.22%									
25											
26	Non-Summer (Billable Demand)	222,249						Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%						222,249	$ 17.13	$ 3,808,168	$ 3,808,168
28	Demand Transmission (Non-Summer kW-Month)	72.78%									$ -
29	Demand Substation (Non-Summer kW-Month)	72.78%									
30	Demand Distribution Primary (Non-Summer kW-Month)	72.78%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.78%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	Energy Components	205,855,705								$ 1,060,884	$ 1,060,884
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer On-Peak	18,487,920						18,487,920	$ 0.0082566	$ 152,647	$ 152,647
39	Summer Off-Peak	37,376,551						37,376,551	$ 0.0042880	$ 160,272	$ 160,272
40	Non-Summer On-Peak	47,732,027						47,732,027	$ 0.0064835	$ 309,472	$ 309,472
41	Non-Summer Off-Peak	102,259,207						102,259,207	$ 0.0042880	$ 438,493	$ 438,493
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	Other Rate Components and Credits				$ (1,387,892)					$ (830,907)	$ (830,907)
46											
47	Billable RkVA Summer	5,373			$ 1,451	$0.27		5,373	$0.27	$ 1,451	$ 1,451
48	Billable RkVA Non-Summer	11,561			$ 3,121	$0.27		11,561	$0.27	$ 3,121	$ 3,121
49	Post-Rider 8 Discounts Summer (Sub)	36,819			($582,839)	($15.83)		36,819	($9.50)	($349,703)	$ (349,703)
50	Post-Rider 8 Discounts Summer (Pri)	0			$0	($15.83)		0	($9.50)	$0	$ -
51	Post-Rider 8 Discounts Non-Summer (Sub)	109,705			($809,626)	($7.38)		109,705	($4.43)	($485,775)	$ (485,775)
52	Post-Rider 8 Discounts Non-Summer (Pri)	0			$0	($4.08)		0	($2.45)	$0	$ -
53											
54	Total		$ -		$ -					$ 6,299,121	$ 6,299,121
55											$ (835,479)

PNM EXHIBIT JCA-16

Schedule: 36B — **Special Service -Renewable Energy Resources**

Source: SC-5

$ 2,263,138

Embedded Cost Component

Line No.	(A)	(B) Billing Units (Test Year)	(C) Cost Based Revenue (ECCOSS)	(D) Rates at Cost Based Revenue	(E) Banded Revenue	(F) Rates at Banded Revenue	(G)	(H) 35B Billing Units (Test Year)	(I) Proposed Rates	(J) Proposed Revenue	(K) Total Proposed Revenue
1	*Customer Components*	12							$ 2,366.39	$ 28,397	$ 28,397
2	*Summer*	3						Summer			
3	Customer Services (per customer/per month)							3	$ 2,366.39	$ 7,099	$ 7,099
4	Customer Meter (per customer/per month)										$ -
5	Customer Meter Reading (per customer/per month)										
6	Customer Billing and Collection (per customer/per month)										
7	Customer Service and Information (per customer/per month)										
8	Customer Other (per customer/per month)										
9											
10	*Non-Summer*	9						Non-Summer			
11	Customer Services (per customer/per month)							9	$ 2,366.39	$ 21,298	$ 21,298
12	Customer Meter (per customer/per month)										$ -
13	Customer Meter Reading (per customer/per month)										
14	Customer Billing and Collection (per customer/per month)										
15	Customer Service and Information (per customer/per month)										
16	Customer Other (per customer/per month)										
17								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
18	*Demand Components*	268,700							$ 4.09	$ 1,098,921	$ 1,098,921
19	*Summer (Billable Demand)*	74,500						Summer			
20	Demand Production (Summer kW-Month)	37.84%						74,500	$ 4.09	$ 304,688	$ 304,688
21	Demand Transmission (Summer kW-Month)	27.73%									$ -
22	Demand Substation (Summer kW-Month)	27.73%									
23	Demand Distribution Primary (Summer kW-Month)	27.73%									
24	Demand Distribution Secondary (Summer kW-Month)	27.73%									
25											
26	*Non-Summer (Billable Demand)*	194,200						Non-Summer			
27	Demand Production (Non-Summer kW-Month)	62.16%						194,200	$ 4.09	$ 794,233	$ 794,233
28	Demand Transmission (Non-Summer kW-Month)	72.27%									$ -
29	Demand Substation (Non-Summer kW-Month)	72.27%									
30	Demand Distribution Primary (Non-Summer kW-Month)	72.27%									
31	Demand Distribution Secondary (Non-Summer kW-Month)	72.27%									
32								Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
33	*Energy Components*	37,966,258								$ 258,518	$ 258,518
34											
35	Energy Fuel (kWh)										
36	Energy Non-Fuel (kWh)										
37											
38	Summer	8,398,339						8,398,339	$ 0.0068092	$ 57,186	$ 57,186
39											$ -
40	Non-Summer	29,567,919						29,567,919	$ 0.0068092	$ 201,333	$ 201,333
41											$ -
42											
43											
44		Billing Units (Test Year)			Proposed Revenue	Proposed Rates		Billing Units (Test Year)	Proposed Rates	Proposed Revenue	
45	*Other Rate Components and Credits*				$ 877,302					$ 877,302	$ 877,302
46											
47											
48											
49											
50	Contribution to Generation Credit	37,966,258			$ 877,302	$ 0.0231074		37,966,258	$ 0.0231074	$ 877,302	
51											
52											
53											
54	Total		$ -		$ -					$ 2,263,138	$ 2,263,138

$ -

PNM EXHIBIT JCA-16

Schedule 20 Streetlight Rate Design Workpaper #1 (Phase 1)

Rate Design Component Proof-Of Revenue

Line No.	Lt-Pl Code Type	Det Type	Description	Light-Pole Own.	kWh / Unit	Billable Units	kWh	Current Rates	Current Revenues	Phase 1 Proposed Rates	Phase 1 Proof-Of_Revenue
					[A]	[B]	[C]	[D]	[E] = [B] * [D] (Except for Lns. 21, 22, 25 and 47, where [E] = [C] * [D])	[F']	[G'] = [B] * [F'] (Except for Lns. 21, 22, 25 and 47, where [E] = [C] * [F'])
1	D	Lights	175W Mercury Vapor and Streetlight	PNM	73	50,628	3,695,844	$14.14	$715,880	$13.97	$707,273
2	F	Lights	400W Mercury Vapor Streetlight	PNM	162	5,604	907,848	$21.47	$120,318	$21.12	$118,356
3	U	Lights	55W Low Pressure Sodium Street Light	PNM	28	11,652	326,256	$12.70	$147,980	$13.49	$157,185
4	V	Lights	135W Low Pressure Sodium Street Light	PNM	63	288	18,144	$17.13	$4,933	$18.34	$5,282
5	S	Lights	70W High Pressure Sodium Street Light	PNM	31	312	9,672	$10.95	$3,416	$12.06	$3,763
6	A	Lights	100W High Pressure Sodium Street Light	PNM	45	116,160	5,227,200	$12.02	$1,396,243	$13.25	$1,539,120
7	T	Lights	200W High Pressure Sodium Street Light	PNM	89	11,772	1,047,708	$14.99	$176,462	$16.00	$188,352
8	B	Lights	250W High Pressure Sodium Street Light	PNM	107	66,900	7,158,300	$17.29	$1,156,701	$18.77	$1,255,713
9	I	Lights	400W High Pressure Sodium Flood Light	PNM	165	8,844	1,459,260	$21.70	$191,915	$23.20	$205,181
10	C	Lights	400W High Pressure Sodium Street Light	PNM	165	6,168	1,017,720	$21.70	$133,846	$23.20	$143,098
11	D	Lights	175W Mercury Vapor and Streetlight	Cust	73	28,284	2,064,732	$5.54	$156,693	$5.58	$157,825
12	F	Lights	400W Mercury Vapor Streetlight	Cust	162	4,608	746,496	$12.30	$56,678	$12.39	$57,093
13	U	Lights	55W Low Pressure Sodium Street Light	Cust	28	0	0	$2.13	$0	$2.15	$0
14	V	Lights	135W Low Pressure Sodium Street Light	Cust	63	0	0	$4.78	$0	$4.82	$0
15	S	Lights	70W High Pressure Sodium Street Light	Cust	31	564	17,484	$2.35	$1,325	$2.37	$1,337
16	A	Lights	100W High Pressure Sodium Street Light	Cust	45	146,460	6,590,700	$3.42	$500,893	$3.44	$503,822
17	T	Lights	200W High Pressure Sodium Street Light	Cust	89	0	0	$6.76	$0	$6.81	$0
18	B	Lights	250W High Pressure Sodium Street Light	Cust	107	82,044	8,778,708	$8.12	$666,197	$8.18	$671,120
19	I	Lights	400W High Pressure Sodium Flood Light	Cust	165	804	132,660	$12.53	$10,074	$12.62	$10,146
20	C	Lights	400W High Pressure Sodium Street Light	Cust	165	59,808	9,868,320	$12.53	$749,394	$12.62	$754,777
21		Lights	Metered	PNM		0	473,460	$0.1940070	$91,855	$0.2072220	$98,111
22		Lights	Metered	Cust		0	310,428	$0.0561839	$17,441	$0.0584182	$18,135
23		Poles	Wood Pole	PNM		105,768		$4.86	$514,032	$5.43	$574,320
24		Poles	Non-Wood Pole	PNM		49,752		$9.45	$470,156	$10.54	$524,386
25	L2Z5	CAR	Metered Streetlighting (Cust Owned)	Cust		0	310,428	$0.0000000	$0	$0.0000000	$0
26	L3D1	CAR	175W MV SL (Cust, 1x73 kWh/Unit)	Cust	73			$0.00	$0	$0.00	$0
27	L7D1	CAR	175W MV SL (Cust, 1x73 kWh/Unit)	Cust	73			$0.00	$0	$0.00	$0
28	L8D1	CAR	175W MV SL (Cust, 1x73 kWh/Unit)	Cust	73			$0.00	$0	$0.00	$0
29	L7D3	CAR	175W MV SL (Cust, 1x73 kWh/Unit)	Cust	73			$0.00	$0	$0.00	$0
30	L8D3	CAR	175W MV SL (Cust, 1x73 kWh/Unit)	Cust	73			$0.00	$0	$0.00	$0
31	L7F1	CAR	400W MV SL (Cust, 1x162 kWh/Unit)	Cust	162			$0.00	$0	$0.00	$0
32	L8F1	CAR	400W MV SL (Cust, 1x162 kWh/Unit)	Cust	162			$0.00	$0	$0.00	$0
33	L7F3	CAR	400W MV SL (Cust, 1x162 kWh/Unit)	Cust	162			$0.00	$0	$0.00	$0
34	L8F3	CAR	400W MV SL (Cust, 1x162 kWh/Unit)	Cust	162	948	153,576	$0.00	$0	$0.00	$0
35	L7A1	CAR	100W HPS SL (Cust, 1x45 kWh/Unit)	Cust	45			$0.00	$0	$0.00	$0
36	L8A1	CAR	100W HPS SL (Cust, 1x45 kWh/Unit)	Cust	45	156	7,020	$0.00	$0	$0.00	$0
37	L7A3	CAR	100W HPS SL (Cust, 1x45 kWh/Unit)	Cust	45			$0.00	$0	$0.00	$0
38	L8A3	CAR	100W HPS SL (Cust, 1x45 kWh/Unit)	Cust	45			$0.00	$0	$0.00	$0
39	L7T1	CAR	200W HPS SL (Cust, 1x89 kWh/Unit)	Cust	89			$0.00	$0	$0.00	$0
40	L8T1	CAR	200W HPS SL (Cust, 1x89 kWh/Unit)	Cust	89			$0.00	$0	$0.00	$0
41	L7T3	CAR	200W HPS SL (Cust, 1x89 kWh/Unit)	Cust	89			$0.00	$0	$0.00	$0
42	L8T3	CAR	200W HPS SL (Cust, 1x89 kWh/Unit)	Cust	89			$0.00	$0	$0.00	$0
43	L7C1	CAR	400W HPS SL (Cust, 1x165 kWh/Unit)	Cust	165			$0.00	$0	$0.00	$0
44	L8C1	CAR	400W HPS SL (Cust, 1x165 kWh/Unit)	Cust	165	12	1,980	$0.00	$0	$0.00	$0
45	L7C3	CAR	400W HPS SL (Cust, 1x165 kWh/Unit)	Cust	165			$0.00	$0	$0.00	$0
46	L8C3	CAR	400W HPS SL (Cust, 1x165 kWh/Unit)	Cust	165	684	112,860	$0.00	$0	$0.00	$0
47	L1Z5	CAR	Metered Streetlighting (PNM Owned)	PNM		0	473,460	($0.0970103)	($45,930)	($0.0934736)	($44,256)
48	L3D2	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73	3,720	271,560	($11.90)	($44,268)	($11.46)	($42,631)
49	L4D2	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73	120	8,760	($16.49)	($1,979)	($16.05)	($1,926)
50	L7D2	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73	7,176	523,848	($7.04)	($50,519)	($6.60)	($47,362)
51	L8D2	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73			($7.04)	$0	($6.60)	$0
52	L3D4	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73	72	5,256	($11.90)	($857)	($11.46)	($825)
53	L4D4	CAR	175W MV SL (PNM, 1x73 kWh/Unit)	PNM	73	468	34,164	($16.49)	($7,717)	($16.05)	($7,511)
54	L3F2	CAR	400W MV SL (PNM, 1x162 kWh/Unit)	PNM	162	480	77,760	($10.34)	($4,963)	($9.44)	($4,531)
55	L4F2	CAR	400W MV SL (PNM, 1x162 kWh/Unit)	PNM	162	12	1,944	($12.24)	($147)	($11.34)	($136)
56	L7F2	CAR	400W MV SL (PNM, 1x162 kWh/Unit)	PNM	162	1,212	196,344	($5.48)	($6,642)	($4.58)	($5,551)
57	L8F2	CAR	400W MV SL (PNM, 1x162 kWh/Unit)	PNM	162			($2.79)	$0	($1.89)	$0
58	L4F4	CAR	400W MV SL (PNM, 1x162 kWh/Unit)	PNM	162	24	3,888	($12.24)	($294)	($11.34)	($272)
59	L3U2	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28	5,280	147,840	($7.39)	($39,019)	($6.95)	($36,696)
60	L4U2	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28	12	336	($11.98)	($144)	($11.54)	($138)
61	L7U2	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28	3,936	110,208	($2.53)	($9,958)	($2.09)	($8,226)
62	L8U2	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28			($2.53)	$0	($2.09)	$0
63	L3U4	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28	1,260	35,280	($7.39)	($9,311)	($6.95)	($8,757)
64	L4U4	CAR	55W LPS SL (PNM, 1x28 kWh/Unit)	PNM	28	1,164	32,592	($11.98)	($13,945)	($11.54)	($13,433)
65	L3V2	CAR	135W LPS SL (PNM, 1x63 kWh/Unit)	PNM	63	12	756	($7.68)	($92)	($6.78)	($81)
66	L7V2	CAR	135W LPS SL (PNM, 1x63 kWh/Unit)	PNM	63	12	756	($2.82)	($34)	($1.92)	($23)
67	L4V4	CAR	135W LPS SL (PNM, 1x63 kWh/Unit)	PNM	63	264	16,632	($12.27)	($3,239)	($11.37)	($3,002)
68	L3A2	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	7,896	355,320	($6.93)	($54,719)	($6.49)	($51,245)
69	L4A2	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	72	3,240	($2.64)	($190)	($2.20)	($158)
70	L7A2	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	6,912	311,040	($2.07)	($14,308)	($1.63)	($11,267)
71	L8A2	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	48	2,160	$0.00	$0	$0.00	$0
72	L3A4	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	1,332	59,940	($3.83)	($5,102)	($3.39)	($4,515)
73	L4A4	CAR	100W HPS SL (PNM, 1x45 kWh/Unit)	PNM	45	1,584	71,280	($8.42)	($13,337)	($7.98)	($12,640)
74	L3T2	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89	1,500	133,500	($7.70)	($11,550)	($7.26)	($10,890)
75	L4T2	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89	1,764	156,996	($3.95)	($6,968)	($3.51)	($6,192)
76	L7T2	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89	1,068	95,052	($2.84)	($3,033)	($2.40)	($2,563)
77	L8T2	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89			$0.00	$0	$0.00	$0
78	L3T4	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89	36	3,204	($5.02)	($181)	($4.58)	($165)
79	L4T4	CAR	200W HPS SL (PNM, 1x89 kWh/Unit)	PNM	89	7,404	658,956	($2.98)	($22,064)	($2.54)	($18,806)
80	L3C2	CAR	400W HPS SL (PNM, 1x165 kWh/Unit)	PNM	165	324	53,460	($10.61)	($3,438)	($9.71)	($3,146)
81	L4C2	CAR	400W HPS SL (PNM, 1x165 kWh/Unit)	PNM	165	12	1,980	($7.67)	($92)	($6.77)	($81)
82	L7C2	CAR	400W HPS SL (PNM, 1x165 kWh/Unit)	PNM	165	408	67,320	($5.75)	($2,346)	($4.85)	($1,979)
83	L8C2	CAR	400W HPS SL (PNM, 1x165 kWh/Unit)	PNM	165			$0.00	$0	$0.00	$0
84	L4C4	CAR	400W HPS SL (PNM, 1x165 kWh/Unit)	PNM	165	36	5,940	($7.67)	($276)	($6.77)	($244)
85		Totals				600,900	49,850,940		$6,905,774		$7,345,146
									$6,896,606		$7,344,993
									$9,168		$153

Rate 6 Private Lighting Rate Design Workpaper #1 (Phase 1)

Table 1: By Rate Code Proof-Of Revenue - Current and Proposed Rates

Line No.	Light / Pole Description - (Rate Code)	Determinants	Current Rates	Current Revenues	Phase 1 Proposed Rates	Phase 1 Proposed Revenues
1	175W MV Lt. (73 kWh) - (LA12)	30,432 Units	$11.39	$346,620	$12.25	$372,792
2	175W MV Lt (73 kWh) - (LA1A)	14,304 Units	$11.39	$162,923	$12.25	$175,224
3	400W MV Lt (162 kWh) - (LAFA)	2,820 Units	$22.55	$63,591	$24.44	$68,921
4	400W MH Lt (162 kWh) - (LAMA)	3,036 Units	$24.54	$74,503	$26.36	$80,029
5	1,000W MH Lt (380 kWh) - (LANA)	264 Units	$53.03	$14,000	$57.46	$15,169
6	100W HPS Lt (45 kWh) - (LA32)	62,688 Units	$9.15	$573,595	$9.66	$605,566
7	100W HPS Lt (45 kWh) - (LA3A)	26,604 Units	$9.15	$243,427	$9.66	$256,995
8	200W HPS Lt (89 kWh) - (LAOA)	672 Units	$14.94	$10,040	$15.89	$10,678
9	200W HPS Lt (89 kWh) - (LATA)	10,128 Units	$14.94	$151,312	$15.89	$160,934
10	400W HPS FL (165 kWh) - (LA42)	22,056 Units	$24.99	$551,179	$26.91	$593,527
11	400W HPS FL (165 kWh) (30' Wood Pole) - (LB42)	6,276 Units	$27.98	$175,602	$29.69	$186,334
12	400W HPS FL (165 kWh) (35' Wood Pole) - (LC42)	8,124 Units	$27.98	$227,310	$29.69	$241,202
13	400W HPS FL (165 kWh) (40' Wood Pole) - (LD42)	180 Units	$27.98	$5,036	$29.69	$5,344
14	400W HPS Lt (165 kWh) - (LA4A)	300 Units	$24.99	$7,497	$26.91	$8,073
15	Pole Charge (wood) - (L0LA)	20,784 Units	$2.99	$62,144	$2.78	$57,780
16	175W MV Lt. (73 kWh) - (LA12)	2,221,536 kWh				
17	175W MV Lt (73 kWh) - (LA1A)	1,044,192 kWh				
18	400W MV Lt (162 kWh) - (LAFA)	456,840 kWh				
19	400W MH Lt (162 kWh) - (LAMA)	491,832 kWh				
20	1,000W MH Lt (380 kWh) - (LANA)	100,320 kWh				
21	100W HPS Lt (45 kWh) - (LA32)	2,820,960 kWh				
22	100W HPS Lt (45 kWh) - (LA3A)	1,197,180 kWh				
23	200W HPS Lt (89 kWh) - (LAOA)	59,808 kWh				
24	200W HPS Lt (89 kWh) - (LATA)	901,392 kWh				
25	400W HPS FL (165 kWh) - (LA42)	3,639,240 kWh				
26	400W HPS FL (165 kWh) (30' Wood Pole) - (LB42)	1,035,540 kWh				
27	400W HPS FL (165 kWh) (35' Wood Pole) - (LC42)	1,340,460 kWh				
28	400W HPS FL (165 kWh) (40' Wood Pole) - (LD42)	29,700 kWh				
29	400W HPS Lt (165 kWh) - (LA4A)	49,500 kWh				
30	Pole Charge (wood) - (L0LA)	0 kWh				
31	Class kWh	15,388,500 kWh				
32	Totals	15,388,500		$2,668,780		$2,838,568
33	Target Totals	15,388,500		$2,668,780		$2,838,519
34	Difference From Targets			$0		$49
						6.4%

Analysis of LCFC Rider Rate from 2010 through 2017

PNM Exhibit JCA-17

Is contained in the following 1 page

PNM Exhibit JCA-17

Estimation of Historical Residential and Small Power LCFC Rider Rates - Interclass Subsidization

Residential (1A/1B)

	A	B	C=A*B	D	E=C/D
	Authorized Fixed Cost Recovery Factor	Cumulative Annual Energy Efficiency Savings (kwh)	Lost Fixed Cost Amount	Actual kWh Sales	LCFC Rider Rate
2011	$ 0.0813309	28,348,073	$ 2,305,576	3,368,666,836	$ 0.0006844
2012	$ 0.0813309	70,335,553	$ 5,720,457	3,329,079,055	$ 0.0017183
2013	$ 0.0813309	106,723,221	$ 8,679,900	3,290,415,646	$ 0.0026379
2014	$ 0.0813309	146,412,641	$ 11,907,878	3,161,537,412	$ 0.0037665
2015	$ 0.0813309	160,594,716	$ 13,061,320	3,207,396,685	$ 0.0040722
2016*	$ 0.0827825	155,828,903	$ 12,899,911	3,160,866,281	$ 0.0040811
2017	$ 0.0871373	152,026,884	$ 13,247,212	3,178,704,448	$ 0.0041675

Small Power (2A/2B)

	F	G	H=F*G	I	J=H/I
2011	$ 0.0768767	4,504,494	$ 346,291	965,649,432	$ 0.0003586
2012	$ 0.0768767	11,785,254	$ 906,011	966,425,575	$ 0.0009375
2013	$ 0.0768767	20,093,933	$ 1,544,755	961,272,783	$ 0.0016070
2014	$ 0.0768767	25,529,702	$ 1,962,639	938,305,823	$ 0.0020917
2015	$ 0.0768767	27,676,991	$ 2,127,715	961,585,973	$ 0.0022127
2016*	$ 0.0801700	27,139,871	$ 2,175,804	927,490,676	$ 0.0023459
2017	$ 0.0900500	26,572,215	$ 2,392,828	924,331,096	$ 0.0025887

Combined

	K=(C+H)/(D+I)	L=D*K	M=I*K	N=L-C	O=M-H
	LCFC Rider	Residential Lost Fixed Cost	Small Power Lost Fixed Cost	Residential Subsidy	Small Power Subsidy
2011	$ 0.0006118	$ 2,061,052	$ 590,814	$ (244,523)	$ 244,523
2012	$ 0.0015427	$ 5,135,610	$ 1,490,858	$ (584,847)	$ 584,847
2013	$ 0.0024048	$ 7,912,942	$ 2,311,713	$ (766,958)	$ 766,958
2014	$ 0.0033832	$ 10,696,058	$ 3,174,460	$ (1,211,821)	$ 1,211,821
2015	$ 0.0036433	$ 11,685,647	$ 3,503,388	$ (1,375,672)	$ 1,375,672
2016*	$ 0.0036875	$ 11,655,616	$ 3,420,099	$ (1,244,295)	$ 1,244,295
2017	$ 0.0038118	$ 12,116,655	$ 3,523,385	$ (1,130,557)	$ 1,130,557

*Prorated pursuant to Final Order in Case No. 15-00261-UT. Assumes no changes to billing determinants for the Test Period in Case No. 15-00261-UT.

Rate 1A – Residential Bill Impacts

PNM Exhibit JCA-18

Is contained in the following 1 page

Rate 1A - Residential Bill Impacts at Proposed Rates

1		Current Rates	Proposed Rates		Current Rates	Proposed Rates	
2	Active Months	Jun-Aug	Jun-Aug	Active Months	Sep-May	Sep-May	
3	# of Months	3	3	# of Months	9	9	
4	Cust. Charge	$7.00	$ 13.77	Cust. Charge	$7.00	$ 13.77	per bill
5	Block 1 kWh	$0.0767429	$0.0832830	Block 1 kWh	$0.0767429	$0.0832830	per kWh
6	Block 2 kWh	$0.1221238	$0.1221238	Block 2 kWh	$0.1053759	$0.1106447	per kWh
7	Block 3 kWh	$0.1472299	$0.1398684	Block 3 kWh	$0.1198334	$0.1200461	per kWh
8	Block 1 Size	450	450	Block 1 Size	450	450	per kWh
9	Block 2 Size	450	450	Block 2 Size	450	450	per kWh
10	RER	$0.0069614	$0.0069614	RER	$0.0069614	$0.0069614	per kWh (all)
11	FPPCAC	$0.0198407	$0.0198407	FPPCAC	$0.0198407	$0.0198407	
12	EE	3.207%	3.207%	EE	3.207%	3.207%	per kWh

13													
14		**Summer Months**				**Non-Summer Months Months**				**Annual Average Bill**			
15	kWh Usage	Current Rates	Proposed Rates	Change	%	Current Rates	Proposed Rates	Change	%	Current Rates	Proposed Rates	Change	%
16	0	$7.22	$14.21	$6.99	96.7%	$7.22	$14.21	$6.99	96.7%	$7.22	$14.21	$6.99	96.7%
17	200	$28.09	$36.42	$8.34	29.7%	$28.09	$36.42	$8.34	29.7%	$28.09	$36.42	$8.34	29.7%
18	250	$33.30	$41.98	$8.67	26.0%	$33.30	$41.98	$8.67	26.0%	$33.30	$41.98	$8.67	26.0%
19	500	$61.72	$71.75	$10.02	16.2%	$60.86	$71.16	$10.30	16.9%	$61.08	$71.30	$10.23	16.7%
20	**563**	**$71.25**	**$81.27**	**$10.02**	**14.1%**	**$69.29**	**$79.93**	**$10.64**	**15.4%**	**$69.78**	**$80.27**	**$10.49**	**15.03%**
21	600	$76.84	$86.86	$10.02	13.0%	$74.25	$85.09	$10.84	14.6%	$74.89	$85.53	$10.64	14.2%
22	700	$91.95	$101.98	$10.02	10.9%	$87.63	$99.02	$11.38	13.0%	$88.71	$99.76	$11.04	12.4%
23	750	$99.51	$109.54	$10.02	10.1%	$94.33	$105.98	$11.66	12.4%	$95.62	$106.87	$11.25	11.8%
24	1,000	$139.89	$149.16	$9.26	6.6%	$129.28	$141.78	$12.49	9.7%	$131.94	$143.62	$11.69	8.9%
25	2,000	$316.95	$318.62	$1.67	0.5%	$278.07	$290.78	$12.71	4.6%	$287.79	$297.74	$9.95	3.5%

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 533	)	**Case No. 16-00276-UT**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant	)	

AFFIDAVIT

STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

JULIO C. AGUIRRE, Lead Pricing Analyst in the Pricing and Regulatory Services Department at Public Service Company of New Mexico, upon being duly sworn according to law, under oath, deposes and states: I have read the foregoing **Direct Testimony of Julio C. Aguirre** and it is true and accurate based on my own personal knowledge and belief.

GCG # 522509

SIGNED this 1st day of December, 2016.

JULIO C. AGUIRRE

SUBSCRIBED AND SWORN to before me this 1st day of December, 2016.

Ronda Morehead

NOTARY PUBLIC IN AND FOR
THE STATE OF NEW MEXICO

My Commission Expires:

OFFICIAL SEAL
Ronda Morehead
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 9/5/19