

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

**IN THE MATTER OF PUBLIC SERVICE)
COMPANY OF NEW MEXICO'S APPLICATION)
FOR APPROVAL OF PURCHASED POWER)
AGREEMENTS, ENERGY STORAGE)
AGREEMENTS, AND CERTIFICATE OF PUBLIC)
CONVENIENCE AND NECESSITY FOR 2029-2032) Docket No. 26-0000 ____
SYSTEM RESOURCES AND THE ABANDONMENT)
OF THE FOUR CORNERS POWER PLANT)
)
PUBLIC SERVICE COMPANY OF NEW MEXICO,)
)
Applicant.)
_____)**

**DIRECT TESTIMONY
OF
JULIO C. AGUIRRE**

May 29, 2026

NMPRC DOCKET NO. 26-0000
INDEX TO THE DIRECT TESTIMONY OF JULIO C. AGUIRRE

WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

1	I.	INTRODUCTION AND PURPOSE	1
2	II.	REQUESTED RESOURCES AND LOAD FORECASTS.....	3
3		A. ASSESSMENT OF INCREMENTAL COSTS TO SERVE LARGE LOADS	
4		11
5		B. ALLOCATION OF PNM-OWNED GENERATION ASSETS.....	19
6		C. ALLOCATION OF PURCHASED POWER AGREEMENTS (“PPAS”) AND	
7		ENERGY STORAGE AGREEMENTS (“ESAS”).....	22
8		D. ALLOCATION OF TRANSMISSION RELATED COSTS.....	25
9	III.	RATE IMPACT FOR RESIDENTIAL CUSTOMERS	27
10	IV.	CONCLUSION.....	33

SPONSORED EXHIBITS

PNM Exhibit JCA-1	Education and Professional Qualifications of Julio C. Aguirre
PNM Exhibit JCA-2	Illustrative Class Allocation of Preferred Portfolio Revenue Requirement (Test Year 2031)
PNM Exhibit JCA-3	Illustrative Functionalization of Preferred Portfolio Revenue Requirement (Test Year 2031)
PNM Exhibit JCA-4	Illustrative Rate Impact on Residential Customers of Preferred Portfolio Revenue Requirement (Test Year 2031)

AFFIDAVIT

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000__**

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I. INTRODUCTION AND PURPOSE

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

A. My name is Julio C. Aguirre. I am the Director, Pricing Customer Strategy, for Public Service Company of New Mexico (“PNM” or “Company”). My business address is 414 Silver Avenue SW, Albuquerque, New Mexico 87102.

Q. Please summarize your educational background and professional qualifications.

A. PNM Exhibit JCA-1 describes my educational and professional qualifications.

Q. Please describe the responsibilities of the Pricing and Customer Strategy Department.

A. The Pricing and Customer Strategy Department is responsible for designing and implementing effective pricing strategies that result in electric offerings that strive to provide customers with accurate price signals and that align with regulatory requirements while reflecting the Company’s market and financial goals. As part of its role in the Company, my team is responsible for the preparation of PNM's retail class cost of service (“COS”) studies, the retail rate design of new or revised proposed tariffs in the Company’s jurisdiction, as well as performing the load forecasting and load research functions.

Q. Have you previously testified in regulatory proceedings?

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** Yes, PNM Exhibit JCA-1 also lists the cases in which I have testified before the
2 New Mexico Public Regulation Commission (“NMPRC” or “Commission”).
3

4 **Q.** **What is the purpose of your testimony?**

5 **A.** I present an illustrative ratemaking framework to recover the revenue requirement
6 associated with PNM’s preferred resource portfolio presented in this case. My
7 testimony addresses the allocation of costs among certain rate classes, and
8 estimated impacts associated with the set of new electric generation, storage and
9 transmission resources proposed by PNM in this application in a manner that is
10 consistent with regulatory precedent while utilizing previously approved
11 ratemaking mechanisms. I also present the estimated rate impact on residential
12 customers of these resources for calendar year 2031, which can be seen as a
13 hypothetical “test year”, resulting in the highest projected annual revenue
14 requirement in the planning horizon presented in this filing (i.e., 2029 through
15 2032)

16
17 **Q.** **Is PNM requesting approval of the proposed cost recovery in this proceeding?**

18 **A.** No, the Company is not requesting authorization to recover the costs presented in
19 this filing. The estimated cost allocations and rate impacts are presented for
20 illustration purposes only, to allow the Commission and interested stakeholders to
21 better understand the potential impacts of the preferred resource portfolio.
22 Specifically, as further explained later in my testimony, the Company has
23 performed this analysis using existing rate structures and cost allocation

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 methodologies to develop an indicative view of potential rates, recognizing that the
2 ultimate cost recovery approach and rate impacts may differ in future ratemaking
3 proceedings.

4

5 **Q. Will PNM seek recovery of these costs in a future filing?**

6 **A.** Yes, if the proposed resources are approved, the Company expects to request
7 recovery of these costs in future regulatory ratemaking proceedings, such as a
8 general rate case or any other appropriate filing as determined by the Commission.

9

10 **Q. Why does the Company believe it is beneficial to present information on**
11 **potential customer rate impacts now?**

12 **A.** Providing reasonable estimates of the expected rate impact of new resources
13 improves transparency and provides additional context that may assist the
14 Commission when evaluating resource planning decisions.

15

16 **II. REQUESTED RESOURCES AND LOAD FORECASTS**

17

18 **Q. Please summarize the revenue impact of the resources PNM is including in this**
19 **application and their anticipated future ratemaking treatment.**

20 **A.** PNM Table JCA-1 below summarizes the resources evaluated in this testimony.
21 The table also shows the regulatory proceeding, the expected jurisdictional
22 allocation proposed for each asset as well as the projected revenue requirement for
23 the one year evaluated in the analysis. The resources presented in this case include

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000___**

1 a combination of renewable generation resources, storage resources, transmission
2 assets as well as a company owned generation asset. Additionally, the analysis
3 includes the projected impact for the abandonment of PNM’s interest in the Four
4 Corners Power Plant (“FCPP” or “Four Corners”) and the extension of the
5 operation of the existing Reeves Generating Station (“Reeves”). These resources
6 are expected to enter service over a multi-year development horizon and are
7 analyzed together to illustrate their combined potential effect on customer rates. A
8 more detailed description of the resources is provided in the Direct Testimonies of
9 PNM witnesses Duane and Barnard. PNM witness Sanders sponsors the estimated
10 revenue requirement used in my analysis.

11
12

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**

1 **PNM Table JCA-1 - Resource List, Estimated Cost and Assumed Ratemaking**

2 **Mechanism**

	Resource	Size (Nameplate Megawatts “MW”)	Technol ogy	Expected Rate Recovery	Jurisdictio n	Est. Annual Rev. Requirements (Test Year 2031, retail only)
1	Palomas PPA	400	Wind	Rider 23*	Retail	\$97,819,518
2	Palomas PPA	400	Wind	Rider 47**	Directly Assigned	\$97,819,518
3	Cat Hills PPA	150	Solar	Rider 23	Retail	\$17,570,068
4	Cat Hills BESS	150/4-hour	Storage	Base Rates	Retail	\$21,362,549
5	Wildcat PPA	90	Solar	Rider 23	Retail	\$7,872,651
6	Wildcat BESS	50/4-hour	Storage	Base Rates	Retail	\$10,890,314
7	Gila Monster BESS	150/4-hour	Storage	Base Rates	Retail	\$19,960,069
8	TAG II BESS	90/8-hour	Storage	Base Rates	Retail	\$20,519,101
9	Britton BESS	60/8-hour	Storage	Base Rates	Directly Assigned	\$13,828,800
10	Encino BESS	110/8-hour	Storage	Base Rates	Retail	\$24,638,900
11	La Luz II	40	Gas	Base Rates/Rider 23	Retail	\$25,824,905
12	Four Corners Abandonment	200	Coal	Base Rates/Rider 23	Retail	(\$38,031,881)
13	Four Corners Securitization	N/A	N/A	Base Rates/Energy Transition Charge	Retail	\$11,177,897
14	Transmission Projects	N/A	N/A	Base Rates/Rider 47	Retail/Direc tly Assigned	\$70,213,674
15	Reeves Extension	146	Gas	Base Rates	Retail	\$19,326,360
	Total					\$420,792,443

3 *Rider 23 refers to Rate Rider No. 23 – Fuel and Purchased Power Cost Adjustment Clause.

4 **Rider 47 refers to Rate Rider No. 47 – Green Energy Rider

5

6

7 **Q. Is PNM including other resources not listed above for purposes of modeling**

8 **the revenue impact of the preferred portfolio?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** Yes, as explained by PNM witnesses Sanders and Duane, PNM is including a
2 “generic” firm resource as a placeholder as part of the modeling assumptions
3 supporting the preferred resource portfolio. PNM is not requesting approval of this
4 generic resource, and the cost estimates provided here (including projected fuel
5 costs) are included to assess the potential cost impact of future firm generation
6 additions that are contemplated under the preferred portfolio and that will be
7 confirmed or adjusted upon completion of PNM’s ongoing Request for Proposals
8 (“RFP”) Supplement process.

9

10 **Q.** **Why is it necessary to include this “generic” resource when evaluating the cost**
11 **impact of the preferred portfolio?**

12 **A.** Even though a specific resource has not yet been selected, incorporating a
13 reasonable placeholder ensures that stakeholders and the Commission can evaluate
14 the overall magnitude and timing of costs that may ultimately be incurred with the
15 preferred portfolio. This approach provides a more comprehensive representation
16 of potential cost impact on retail customers, while preserving flexibility to update
17 assumptions once the Supplemental RFP process is concluded and a specific
18 resource is identified.¹ PNM Table JCA-2 below illustrates the estimated revenue
19 requirement of the generic resource as modeled in the preferred portfolio for 2031.

20

¹ The term “preferred portfolio” in the context of this testimony is used to refer to all resources modeled to determine the projected revenue and rate impact for year 2031, including certain assets (e.g., the generic gas resource) or regulatory requests (e.g., securitization of Four Corners) that are not specifically requested for approval in this case, but that are necessary to provide a comprehensive view of the whole resource portfolio evaluated.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 process, which is discussed in more detail in the testimony of PNM witness Duane.
2 This load forecast is based upon the same modeling assumptions and resulting
3 output of the load forecast presented in PNM’s last rate case filing (i.e., Docket No.
4 24-00089-UT) for the period analyzed in this case, i.e., 2029 through 2032, with
5 two noteworthy changes.

6

7 **Q. What changes were introduced into the load forecast used in this filing when**
8 **compared to the forecast presented in the Company’s last rate case?**

9 **A.** Essentially, the revised load forecast used in this case includes a projection of new
10 large loads that PNM plans to serve in the period 2029-2032, which were not
11 included in the most recent rate case forecast. First, the revised system load forecast
12 includes a new projection for Rate No. 36B which updates the customer’s load
13 forecast based on a more recent expansion plan provided by the customer; and
14 second, the revised forecast incorporates incremental electric load from new
15 economic development projects, including prospective customers that may be
16 attracted and served as a result of the recently enacted Senate Bill 170 (“SB 170”)
17 economic “readiness” regulatory structure that allows utilities to proactively
18 expand available capacity to meet future loads. PNM witnesses Sanders and
19 Williams discuss in more detail the economic development initiatives used in the
20 planning process and the associated load that resulted in the selection of the
21 resources presented in this filing.

22

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **Q. Please explain why the projected increase in load for the period 2029-2032**
2 **required PNM to update the load projections used in its last rate case filing.**

3 **A.** The substantial increase in new load requests prompted PNM to revisit and revise
4 its earlier forecast from the rate case filing. The adjustment to the previous load
5 projections provides an update to the future load conditions expected in the 2029-
6 2032 timeframe that justifies the need for the resources and represents the best
7 information available at the time PNM prepared the resource planning analysis
8 presented in this filing.

9
10 **Q. Why are both customer-provided and internally developed load forecasts**
11 **critical in the resource planning process?**

12 **A.** Customer-provided and internally developed load forecasts are essential inputs to
13 the resource planning process because they collectively provide a comprehensive
14 view of expected future electricity demand. Customer forecasts offer specific
15 insight into anticipated load additions or changes particularly for large customers,
16 while internally developed forecasts capture system-wide trends based on historical
17 data, demographic shifts, and economic indicators. Using both sources allows PNM
18 to better assess future load requirements and plan timely, cost-effective investments
19 in generation, transmission, and other electric infrastructure. As stated above, for
20 this preferred portfolio PNM incorporated internally modeled load projections
21 along with customer-specific load estimates and other anticipated economic
22 development load within PNM's service territory.

23

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **Q. What new customer-specific load is expected from economic development**
2 **growth?**

3 **A.** As further explained by PNM witness Williams, the projected new load associated
4 with economic development includes electric usage estimates for 350 MW of
5 incremental load to serve new data centers and a large electric truck charging station
6 as well as 200 MW of future load growth to be served under the SB 170 regulatory
7 framework. Also, as noted above, the new load forecast projects additional growth
8 from the customer currently being served under Rate No. 36B, which had not been
9 accounted for in the previous load forecast.

10

11 **Q. Why does PNM need to plan to build resources to serve future loads?**

12 **A.** The Company has an obligation to serve its customers and meet their electricity
13 needs as they evolve. As a normal business practice, once a customer requests
14 service and executes a Reimbursement Agreement (“RA”) or an Electric Facilities
15 Agreement (“EFA”), PNM strives to plan and invest in the required infrastructure
16 necessary to serve the customer and to ensure that the Company will be in a position
17 to fulfill its commitments with its customers and to serve the load requested in a
18 timely fashion. In this sense, once PNM and a customer enter a contract to serve a
19 load at a future date, those load projections serve as a planning baseline for the
20 Company’s system planning efforts.

21

22 **Q. Has PNM executed an RA or an EFA with the customers requesting service**
23 **for any of the projected new load discussed above?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** Yes, as of the date of this filing PNM has executed RAs with three customers whose
2 aggregated peak load results in the 350 MW of incremental load projected in the
3 2029-2032 timeframe, and various EFAs under a Special Service Contract executed
4 to serve the load growth of the customer currently served under Rate 36B.

5

6 **Q.** **How else is PNM using the revised load forecast in this case?**

7 **A.** In order to provide consistency, PNM is using the same revised load forecast to
8 calculate updated allocation factors that are used for my illustrative cost allocation
9 analysis and rate impact, as discussed later in my testimony.

10

11 **A. ASSESSMENT OF INCREMENTAL COSTS TO SERVE LARGE LOADS**

12

13 **Q.** **What rate-making mechanism is PNM planning to propose to protect other**
14 **retail customers from the incremental costs potentially created by serving**
15 **large load customers in the future?**

16 **A.** As further explained below, and by PNM witnesses Williams and Sanders, the
17 Company intends to propose a dedicated large load tariff in a future proceeding that
18 will incorporate a ratemaking structure specifically designed to ensure that large
19 load customers pay at least their incremental cost to serve them.² Therefore, any

² PNM expects that the projected new retail load of 350 MW plus the expected 200 MW of load assumed for the SB 170 regulatory structure will be served under a single rate class tariff, that will include the criteria discussed around the recovery of incremental costs and that may include provisions such as: eligibility thresholds based on load size, customer-specific facility charges, minimum billing or contract demand provisions to ensure recovery of fixed costs as well as exit or termination provisions tied to contractual commitments including collateral requirements to address any potential financial exposure created by these loads.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 future regulatory structure proposed for large loads will assess cost allocations by
2 separately identifying the incremental generation, transmission, and other
3 infrastructure or variable costs required to serve these loads.

4

5 **Q. How do you interpret the term “incremental costs” in the context of this**
6 **testimony?**

7 **A.** “Incremental costs” refer to the additional generation, transmission, and related
8 system costs incurred to serve new large load demand. However, these costs include
9 not only investments in new resources required to meet that demand, but also the
10 portion of existing system resources and associated costs incurred to provide
11 service to those loads.

12

13 **Q. Why is PNM including existing resources as part of the “incremental costs”**
14 **calculation to serve new large loads?**

15 **A.** Although existing assets were not originally planned or constructed to serve
16 specifically new large load customers, these new customers (or any other future
17 large load) will nonetheless rely on and benefit from these resources once they are
18 interconnected to the system. Accordingly, PNM expects that any future rate
19 framework for large load customers will assign cost responsibilities not only for the
20 incremental resources needed to serve their load, but also for an appropriate share
21 of the costs associated with existing system assets that are used to provide them
22 with electric service. The Company expects that its future tariff framework will
23 ensure that large load customers are responsible not only for any new resources

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 they drive as part of the proposed portfolio presented in this case, but also for their
2 “fair share” of existing system costs, as determined in a ratemaking proceeding.

3

4 **Q. How does your cost allocation and rate impact analysis account for the**
5 **recovery of incremental costs associated with large load customers?**

6 **A.** In performing my cost allocation and rate impact analysis for the residential class,
7 I have assumed that the Company’s future proposed large load tariff will include a
8 mechanism designed to ensure that any incremental generation, transmission, or
9 other infrastructure costs associated with serving large load customers are borne by
10 those customers. However, it is important to note that the analysis presented in this
11 proceeding is illustrative in nature. It is intended to demonstrate at a high level, how
12 incremental costs could be identified and assigned to large load customers under a
13 new tariff framework. The specific mechanism or mechanisms by which those costs
14 will ultimately be recovered, including tariff language, contractual provisions, and
15 any applicable adjustments, will be more fully developed and presented as part of
16 the Company’s forthcoming large load tariff filing and future ratemaking
17 proceedings. Therefore, the results presented here should not be interpreted as a
18 finalized cost recovery approach, but more as a conceptual representation of how
19 such rate framework may be proposed and implemented in the future.

20

21 **Q. How is PNM estimating incremental resource costs associated with new large**
22 **loads for purposes of modeling your cost allocation analysis?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** The Company expects that any incremental generation or transmission resources
2 required to serve new large load customers will be recovered from those
3 incremental loads. To estimate the cost impact of this approach, PNM calculates
4 the costs of any additional generation, transmission, and related infrastructure
5 needed to reliably serve the new large load customers. This includes identifying
6 their allocated share of existing resources as well as all the costs incurred for new
7 generation and transmission resources required to serve the new large loads demand
8 and assigning them those costs. PNM witness Sanders’s table KTS-2 provides a list
9 of the resources and the associated costs assigned to each specific load segment.

10

11 **Q.** **How will this cost allocation approach ensure that incremental costs to serve**
12 **large loads are not borne by other customers?**

13 **A.** This approach of calculating the incremental costs incurred to serve the incremental
14 large loads would ensure that residential and other existing retail customers will
15 remain insulated from cost impacts associated with serving new large load
16 customers. In addition to their share of existing resources, any new resources added
17 to meet incremental demand will be directly linked to the customers driving that
18 demand. These incremental costs may also separately identify certain
19 customer-specific costs recovered through a contractual obligation in the form of
20 an EFA or an Energy Service Agreement . As a result, PNM expects that the tariff
21 structure to be proposed to serve large load customers will ensure that these
22 customers pay at least the incremental cost to serve them and that such costs will
23 not be borne by residential customers or other retail classes.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

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Q. What are the estimated incremental costs for new resources and the associated loads assigned to them as part of your illustrative cost allocation?

A. Table JCA-3 below shows the resulting assignment of specific assets and costs (i.e., incremental costs from preferred portfolio) to load segments (i.e., incremental loads) that PNM used to assess cost allocation responsibilities in this resource filing. One the load segments include “Existing Retail” which refers to the preferred portfolio’s allocated costs and incremental load projections of all other existing retail classes aggregated for the test year 2031 analyzed in this testimony.

PNM Table JCA-3 Incremental Cost Estimates of Preferred Portfolio (Annual Revenue Requirement for 2031)					
1	2	3	4	5	6
	Load/Class	Base Rates	Rider 23	Rider 47	Total
3	350 MW New Retail	\$90,546,771	\$94,206,029		\$184,752,800
4	200 MW SB 170 Loads	\$36,372,639	\$56,186,584		\$92,559,223
5	Rate 36B			\$ 145,967,310	\$145,967,310
6	Existing Retail	\$73,374,423	\$4,637,487		\$78,011,910
7	Total	\$200,293,833	\$155,030,100	\$ 145,967,310	\$501,291,243

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Q. What are PNM’s estimated total incremental costs calculated for the preferred portfolio and allocated to large loads?

A. PNM estimates that for the preferred resource portfolio presented in this case, the incremental costs to serve large loads (i.e., 350 MW New Retail and 200 MW of SB 170 load) will be approximately \$423 million in annual revenue requirement for the year 2031. That translates into an average non-fuel base rate plus fuel and

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 purchased power cost rate of approximately \$0.12 per kWh for large load
2 customers, assuming annual energy sales of 3,621,530 MWh.³ In my rate impact
3 analysis, PNM would expect to recover at least that amount per unit from the large
4 loads during the hypothetical test period.⁴ PNM Exhibit JCA-2 describes the full
5 allocation of the test year 2031 revenue requirement to large loads and all other
6 retail classes.

7

8 **Q. What would be PNM’s estimated total rate for large loads if PNM were to**
9 **exclude the costs of the “generic” firm resource discussed above?**

10 **A.** PNM estimates that the average non-fuel base rate plus fuel and purchased power
11 cost rate would be approximately \$0.09 per kWh for large load customers. No other
12 load segments would be impacted, as this resource has been assigned entirely to
13 serve the large loads modeled in the portfolio.

14

15 **Q. How should the Commission interpret the results of the Company’s cost**
16 **allocation modeling outlined in this filing?**

17 **A.** As explained previously, and also as discussed in the testimony of PNM witness
18 Sanders, the results presented in my testimony should be interpreted as illustrative
19 only. While the analysis provides a view of how costs could be allocated and how
20 rates may be affected under the preferred portfolio, it does not represent a proposed

³ Load may also be subject to additional rate riders and other charges as per the terms of the applicable Commission-approved tariffs.

⁴ The number is calculated by adding the revenue requirement of serving the 350 MW of economic development large load plus the 200 MW of SB 170 load, as shown in PNM Exhibit JCA-2, rows 58-59, column (M), and then dividing it by the projected energy sales (i.e., \$421,569,279/3,621,530,000 kWh).

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 or final determination of cost recovery or future rates. All my cost allocations and
2 rate impacts are indicative and are based on current assumptions, existing structures
3 and simplified allocation approaches used in my analysis. The Company will
4 address the actual recovery of costs, including the development of appropriate rate
5 design and allocation methodologies, in a future ratemaking proceeding that will
6 be subject to full review, refinement, and approval by the Commission.

7

8 **Q. Aside from the approach presented earlier, is PNM proposing to actually**
9 **directly assign any of the preferred portfolio costs to any specific rate class or**
10 **customer?**

11 **A.** Yes. Consistent with regulatory precedent and existing approved cost recovery
12 mechanisms, the Company proposes that certain resource investments that are
13 undertaken in response to the load requirements or contractual service
14 arrangements of specific large customers should be directly assigned to those
15 customers. In particular, the costs incurred for the customer served under Rate
16 Schedule 36B – Special Service Rate – Renewable Energy Resources (“Rate 36B”).
17 PNM Table JCA-3 above shows the amount of revenue requirements resulting from
18 the preferred portfolio allocated to Rate 36B.

19

20 **Q. How does the Company’s approach to assign costs directly to the customer**
21 **served under Rate 36B ensure that it does not cause cross-subsidization among**
22 **customer classes?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 A. Directly assigning incremental resource costs to the customer whose load
2 requirements necessitate the investment also helps prevent cross-subsidization.
3 Commission’s approval of the recent amendments to Rate 36B and the
4 accompanying Rider 47 – Green Energy Rider (“Rider 47”) and Rider 49 –
5 Production Cost Allocation Rider (“Rider 49”)⁵ demonstrate that the current service
6 and regulatory structure prevents cross-subsidization and protects other PNM
7 customers, such as the residential class, resulting in no net adverse impact to these
8 customers.

9

10 **Q. What costs is PNM proposing to directly assign to the customer served under**
11 **Rate Schedule 36B?**

12 A. PNM proposes that the costs associated with 400 MW of the Palomas Wind Project
13 be directly assigned to the customer currently served under Rate 36B. These costs
14 will be collected through Rider 47, in accordance with the terms of the Rate 36B
15 tariff and the Special Service Contract currently in effect. Additionally, for
16 modeling purposes, PNM is assuming that this customer will be responsible for
17 fifty percent (50%) of the transmission related costs associated with the Midstate
18 Transmission Line.⁶ PNM witness Barnard explains in more detail the wind
19 resource PPA and the split of costs between the customer served under Rate 36B
20 and other retail customers.

⁵ Amended and approved in NMPRC Case No. 25-00048-UT.

⁶ Currently, customer(s) served under Rate 36B are subject to a transmission demand charge which allows for the recovery of this class’s allocated share of retail transmission related costs as determined in PNM’s last rate case (i.e., 24-00089-UT).

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

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2 **Q. Are there any other portfolio costs directly assigned to the Rate 36B customer?**

3 A. Yes. In a similar way, PNM is assuming that the ESA costs associated with the
4 Britton BESS project also be directly assigned to the customer served under Rate
5 36B. This is also consistent with the provisions of the said tariff and Rider 47.

6

7 **Q. Did PNM develop a complete embedded class cost of service study to estimate
8 the allocation factors used in this proceeding?**

9 A. No. PNM prepared a simplified version of the embedded class cost of service model
10 most recently used in a rate case filing to facilitate its calculations while still
11 providing a reasonable representation of the expected revenue impact of the
12 proposed allocation factors on all retail rates. This approach can be viewed as a
13 reasonable proxy for the allocations that would be expected had the Company
14 conducted a full embedded class cost of service study.

15

16 **B. ALLOCATION OF PNM-OWNED GENERATION ASSETS**

17

18 **Q. If PNM is estimating incremental costs and allocating them specifically to load
19 segments, why is there a need for the use of class allocators for functionalized
20 costs such as generation or transmission?**

21 A. While PNM's analysis identifies and assigns incremental costs to the load segments
22 that drive those investments, it is also important to recognize that certain costs and
23 assets serve multiple customer classes. To the extent that certain resources provide

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 shared system benefits, PNM relies on Commission-approved cost allocation
2 methodologies to determine the appropriate share of those costs for each retail class.
3 For example, all retail customer classes, including large loads, will rely on and
4 benefit from PNM’s existing generation fleet and transmission network.
5 Accordingly, PNM applies standard allocators to assign a portion of those shared
6 costs to each retail class in a manner that reflects their use of the system. This
7 approach ensures that cost responsibility remains consistent with established
8 ratemaking principles and allows the identification and assignment of incremental
9 costs to the customers that drive them.

10

11 **Q. How is PNM proposing to allocate the La Luz II Project 40 MW Gas Plant**
12 **proposed in this case to retail classes?**

13 **A.** Consistent with the methodology used in PNM’s most recent rate case, PNM is
14 using the 4 coincident peak, 3 Summer/1 Winter (“3S1W”) methodology to allocate
15 all generation related costs associated with the La Luz II Project.⁷ This allocation
16 methodology is a type of coincident peak responsibility method of allocating
17 demand costs that divides system capacity costs among customer classes in
18 proportion to the peak demand imposed by each class at the time of 4 monthly
19 system peaks (i.e., 3 monthly peaks in the summer and 1 monthly peak in the
20 winter). This methodology aligns with prior regulatory practice. As noted in PNM

⁷ For ratemaking purposes, the annual revenue requirements assume this asset would be fully depreciated by December 31, 2044.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 witness Sanders' Table KTS-2, this resource is assigned to all the existing retail
2 classes and not to the large load segment.

3

4 **Q. How is PNM proposing to allocate the “Generic Resources” modeled in the**
5 **preferred portfolio to retail classes?**

6 **A.** As explained above, the proposed “Generic Resources” included in the preferred
7 portfolio represent placeholder assumptions for resources that will ultimately be
8 procured through a competitive RFP process. In my analysis this resource has been
9 directly assigned to the large loads segment, i.e., the 350 MW of New Retail and
10 200 MW of SB 170 load. PNM will evaluate the characteristics of the final resource
11 to determine whether this assumed allocation remains the most appropriate
12 methodology.

13

14 **Q. Is PNM requesting that the Commission approve this methodology for the**
15 **allocation of PNM owned generation costs among customer classes?**

16 **A.** No. As noted earlier, the Company is not requesting a determination regarding class
17 allocation treatment in this proceeding. Instead, PNM is providing an illustrative
18 allocation result using the most recently accepted methodology to help the
19 Commission and interested parties understand how the costs associated with the
20 proposed company-owned generation resources could be distributed among
21 customer classes for ratemaking purposes in the future.

22

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **Q. Is PNM planning to propose the same 3S1W methodology for the allocation of**
2 **PNM owned generation costs and retail transmission costs among customer**
3 **classes in future rate cases?**

4 **A.** Not necessarily. The Company has not yet determined what allocation
5 methodology it will propose in future rate cases. Through the Pricing Advisory
6 Committee (“PRAC”), PNM and other participating stakeholders have examined
7 alternative methods and approaches that may be appropriate for consideration.
8 PNM’s ultimate objective is to advance cost-allocation methods that best reflect
9 cost-causation principles and that align with the resource planning process.

10

11 **C. ALLOCATION OF PURCHASED POWER AGREEMENTS (“PPAs”)**
12 **AND ENERGY STORAGE AGREEMENTS (“ESAs”)**

13

14 **Q. How is PNM proposing to allocate and recover the costs for the remaining**
15 **three⁸ requested PPAs in this case?**

16 **A.** Pursuant to NMAC Rule 551.9(A) “...unless otherwise authorized by the
17 Commission, energy costs incurred under a PPA are recoverable through a utility’s
18 fuel and purchased power cost adjustment clause and capacity costs are recoverable
19 through base rates.” Therefore, PNM will seek recovery of these costs through the
20 Rate Rider No. 23 – Fuel and Purchased Power Cost Adjustment Clause (“Rider
21 23”). Similar to how PNM is modeling the allocation and recovery of costs
22 associated with Company-owned generation assets, PNM assumes that the rate

⁸ 400 MW of the Palomas Wind Project allocated to Rate 36B is contracted as a separate PPA.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 framework for large load customers will separately identify fuel and purchased
2 power costs associated with the preferred portfolio and allocate and recover those
3 costs from the specific load segments that drive them.

4

5 **Q. How is PNM proposing to allocate the costs of the ESAs?**

6 **A.** Consistent with the same rule, and the cost allocation criteria resulting from the
7 settlement in PNM's most recent rate case filing, PNM would seek recovery of
8 the ESA's capacity charges through base rates.

9

10 **Q. Is PNM using the 3S1W methodology to allocate the costs of the ESAs?**

11 **A.** Yes, but only for the portion of the costs that are functionalized as generation and
12 transmission-related. Following the most recent regulatory precedent, PNM is
13 functionalizing and subsequently allocating 67% of the ESAs costs as generation-
14 related costs, 30% as transmission-related costs and 3% as distribution-related
15 costs. All these costs are proposed to be allocated and collected through base rates.
16 This proposed functionalization of energy storage resources is consistent with the
17 methodology accepted in PNM's most recent rate case filing (Case No. 24-00089-
18 UT). This criterion would apply to the Cat Hills and the Gila Monster ESA projects
19 proposed in this case.

20

21 **Q. Is the 3S1W data used to allocate generation related costs the same as the used**
22 **to allocate the costs of ESAs functionalized as generation related costs?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** Yes, consistent with PNM’s last rate case, all the ESAs costs included in the
2 revenue requirement presented in this case are classified as 100% demand-related
3 because the costs are incurred contractually by a fixed capacity charge that PNM
4 must pay.

5

6 **Q.** **How would PNM allocate the costs of the ESAs functionalized as transmission**
7 **related or distribution-related costs?**

8 **A.** PNM proposes to apply the same methodologies utilized in its most recent rate case
9 filing, namely a 3S1W allocator for transmission-related costs and using a non-
10 coincident peak allocator for distribution-related costs. The 3S1W allocation is
11 consistent with previous Commission’s precedent for PNM where the approach
12 used for the allocation of generation costs has extended to the allocation of
13 transmission demand costs.

14

15 **Q.** **How will the rest of the PPA’s costs be recovered in rates?**

16 **A.** As mentioned above, given the contractual obligations outlined under Rate 36B,
17 the costs of one of the two PPAs associated with the Palomas PPA Wind Project,
18 will be directly assigned and allocated to one customer and collected through Rider
19 47. Similarly, one hundred percent of the capacity costs projected for the ESA for
20 the Britton BESS project would also be allocated to the customer served under Rate
21 36B and recovered through Rider 47.

22

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **Q. How is PNM approaching the allocation of PPAs and ESAs for purposes of**
2 **determining incremental costs?**

3 **A.** PNM has identified and isolated the costs associated with specific PPAs and ESAs
4 that are assumed to be driven by the incremental load and my analysis assigns those
5 costs to the large load segment in order to estimate the incremental cost of service.
6

7 **Q. How is the Company estimating other future fuel and purchased power costs**
8 **projected for 2031?**

9 **A.** For other existing PPA's and fuel cost projections associated with current
10 generating facilities, PNM has developed a high-level estimate for other fuel and
11 purchased power costs. PNM is estimating the projected costs for 2031 using
12 information from 2030 as a proxy value, as it represents the closest available year
13 within the modeled planning horizon at the time of this filing.
14

15 **D. ALLOCATION OF TRANSMISSION RELATED COSTS**

16
17 **Q. How does the Company propose to allocate transmission-related costs**
18 **associated with the proposed generation resources that are required to**
19 **interconnect the facilities and deliver power to customers?**

20 **A.** As discussed above, all transmission-related costs associated with the proposed
21 generation resources serving multiple rate classes, PNM is using the methodology
22 approved in PNM's most recent rate case filing, i.e., the same 3S1W allocator
23 recognized in prior New Mexico regulatory proceedings as mentioned above. To

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 the extent that transmission facilities provide network system benefits by enabling
2 the delivery of capacity and energy to all retail customers, the Company would
3 expect those costs to be incorporated into transmission plant investment and
4 recovered through base rates in a future proceeding.

5

6 **Q. Has PNM calculated the transmission-related revenue requirement associated**
7 **with each resource?**

8 **A.** Yes. PNM Table JCA-4 below provides a breakdown by each resource of the
9 transmission-related revenue requirement projected for 2031, the year analyzed in
10 my testimony. PNM witness Sanders sponsors these revenue requirement
11 calculations.

12

PNM Table JCA-4

	Resource	Est. Transmission Revenue Requirement (2031)
1	Palomas PPA (Mid-State)	\$ 68,091,977
2	Cat Hills	\$ 302,202
3	Cat Hills BESS	\$ 212,037
4	Wildcat	\$ 514,041
5	Wildcat BESS	\$ 66,440
6	Gila Monster BESS	\$ 307,704
7	TAG BESS	\$ 201,943
8	Britton BESS	\$ 273,004
9	Encino BESS	\$ 244,326
10	Total	\$ 70,213,674

13

14 **Q. How is PNM approaching the recovery of transmission-related costs for**
15 **purposes of determining incremental costs?**

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **A.** For purposes of my analysis, PNM has also identified and isolated the transmission
2 investments that the Company assumes are required to serve incremental load and
3 assigned those costs to the large load segment in order to estimate the incremental
4 cost of service. Specifically, the Company evaluated the transmission facilities,
5 network upgrades, and other transmission-related investments that are necessary
6 for the preferred portfolio and considers those costs as being attributable to that
7 retail incremental demand.

8

9 **III. RATE IMPACT FOR RESIDENTIAL CUSTOMERS**

10

11 **Q.** **What do you discuss in this section of your testimony?**

12 **A.** I discuss the main assumptions used around the cost allocation mechanisms used
13 for the recovery of the preferred portfolio costs in a future proceeding. I also present
14 estimates of the potential rate effects associated with the preferred resource
15 portfolio. This includes discussion of anticipated impacts on residential customers,
16 which is intended to inform the Commission’s evaluation of the potential
17 magnitude of customer impacts while recognizing that final rate treatment will be
18 determined in subsequent proceedings.

19

20 **Q.** **Please summarize PNM’s approach to estimate the rate impact of its preferred**
21 **resource portfolio on Residential customers.**

22 **A.** The retail revenue requirement was first functionalized and then assigned among
23 load segments, including future large load customers as discussed above. Then,

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 these costs were allocated among retail customer classes using energy or demand-
2 based allocation methods. These projected costs were grouped into categories
3 consistent with existing recovery mechanisms, such as base rates, costs directly
4 assigned to customers and fuel or purchased power. The Company then calculated
5 the average residential rate per kWh at full cost of service resulting from the last
6 rate case, and compared it with the estimated 2031 average rate based on the class
7 allocated revenue requirement, reflecting all the additions resulting from the
8 preferred portfolio resources and the projected loads. To facilitate the analysis and
9 comparisons, the proposed average rate under current rates include only the non-
10 fuel base rate (at full cost of service) as well as the fuel and purchased power costs
11 approved recently for Phase II in PNM’s most recent rate case filing (Case No. 24-
12 00089-UT, effective April 1, 2026).

13

14 **Q. Why are you providing a rate impact analysis using full cost of service**
15 **numbers and excluding other revenues and riders currently applied to**
16 **Residential customers?**

17 **A.** Due to uncertainty around future rider levels and potential changes in the
18 Residential rate design, my testimony relies on an apples-to-apples comparison of
19 fully allocated revenue requirement for the Residential class. This avoids making
20 additional assumptions about future adjustments and provides a consistent view of
21 rates at the full cost of service level. Additionally, current Residential rates are not
22 set to recover the full cost of service, so relying on them could distort the
23 comparison.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 **Q. Why did PNM choose 2031 as the “test year” so to speak to estimate the rate**
2 **impact presented in your testimony?**

3 **A.** As explained earlier, the year 2031 is the first full calendar year in which all new
4 proposed resources are expected to be in service, and it also represents the period
5 with the highest projected annual revenue requirement in the planning horizon
6 presented in this filing, that is 2029 through 2032. Therefore, the revenue
7 requirement for 2031 serves as a reasonable reference point for illustrating the
8 maximum potential rate impacts associated with the portfolio.

9

10 **Q. Does your rate impact analysis include other possible rate changes that could**
11 **occur before the study period analyzed in this resource filing?**

12 **A.** No. To keep the analysis straightforward, PNM assumes that non-fuel base rates
13 stay the same from the last rate case through 2030. This assumption is used only to
14 make it easier to compare rate impacts tied to the resource decisions in this filing.
15 My analysis is not meant to predict future rates or suggest that no other rate changes
16 will occur. Keeping rates constant provides a clear and consistent baseline and
17 avoids relying on assumptions about uncertain future costs.

18

19 **Q. How is PNM incorporating the costs savings associated with the Four Corners**
20 **Abandonment?**

21 **A.** The rate impact analysis of year 2031 includes a projected reduction in the non-fuel
22 revenue requirement resulting from the Four Corners abandonment that would
23 otherwise be functionalized as generation-related costs. Additionally, PNM

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 projects a reduction to fuel costs, accounted for through lower projected fuel and
2 purchased power costs. The impact of the abandonment of Four Corners assumes a
3 partial impact on the test year, as it is expected to occur in the month of July 2031.
4 PNM witness Sanders sponsors the revenue requirement offset resulting from the
5 Four Corners abandonment.

6

7 **Q. Did your rate impact for 2031 account for the recovery of any undepreciated**
8 **assets resulting from the Four Corners abandonment?**

9 **A.** Yes. The calculation of the 2031 revenue requirement reflects recovery of
10 undepreciated Four Corners costs, thereby appropriately weighing the associated
11 costs and benefits of the abandonment. However, PNM would expect that in
12 accordance with a future regulatory proceeding, the recovery of these costs could
13 begin no earlier than January 2032 through securitization and a corresponding
14 Energy Transition Charge. For modeling purposes PNM is functionalizing these
15 costs and benefits as production-related and allocating both to base rates. PNM
16 witness Sanders describes in more detail the expected regulatory process for the
17 Four Corners abandonment.

18

19 **Q. How is PNM incorporating the costs associated with the extension of the**
20 **Reeves Gas Plant?**

21 **A.** For purposes of estimating rate impacts in 2031, PNM also calculated the
22 incremental non-fuel revenue requirement associated with the capital expenditures
23 needed to operate Reeves beyond 2030, relative to the costs reflected in the test

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 period of PNM’s most recent rate case. This approach isolates the additional costs
2 attributable to the decision to extend the plant’s operation while recognizing that a
3 portion of Reeves-related costs is already being recovered through existing non-
4 fuel base rates.

5

6 **Q. What is the projected rate impact PNM estimates for the Residential**
7 **customers in 2031?**

8 **A.** Based on current assumptions regarding resource costs, load forecasts, and the
9 currently used allocation methodologies, the Company estimates that average
10 Residential rate could in fact decrease by approximately 14% in 2031, when
11 compared to the current average rates at full cost of service. That means the average
12 rate paid by Residential customers for non-fuel and fuel and purchased power costs
13 could go from the current level of \$0.169573 per kWh to \$0.145641 in 2031. For a
14 typical residential customer using 600 kWh per month, this average rate translates
15 into a total charge of \$101.74/month paid currently that could be reduced to
16 \$87.38/month⁹, once the resources in the preferred portfolio are placed into service
17 and the loads are materialized. This estimate reflects the combined effect of new
18 capital investments, operating costs, and allocation of revenue requirement across
19 customer classes assuming large loads pay for all of their incremental costs. Actual
20 outcomes will depend on future regulatory determinations, updated cost
21 projections, changes in customer usage patterns and the appropriate ratemaking

⁹ Bill does not account for any specific rate design for the Residential class.

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 determinations. Please refer to PNM Exhibit JCA-4 for the calculations supporting
2 the rate impact for the Residential class discussed above.

3

4 **Q. What is the main driver of the potential reduction to residential customers’**
5 **rates resulting from the preferred portfolio?**

6 **A.**The majority of the reduction is driven by a lower allocation of variable energy
7 costs, including Rider 23 costs, to residential customers. My analysis of the
8 hypothetical test year 2031 indicates an approximate 17% decrease in energy-
9 related components compared to the costs residential customers would be
10 responsible for in the absence of changes to other large loads like the ones discussed
11 above. It is also worth noting that for modeling purposes, approximately 84% of
12 the costs associated with the preferred portfolio in 2031 have been assigned to large
13 load segments and not to residential customers. A detailed comparison of the
14 functionalized cost components is provided in PNM Exhibit JCA-4, column (F).

15

16 **Q. How should the Commission weigh potential rate impacts when considering**
17 **whether approval is in the public interest?**

18 **A.**In evaluating resource proposals, it is appropriate for the Commission to consider
19 both the direction, the magnitude of projected rate impacts and the long-term
20 benefits associated with the proposed investments. In addition to the fact that the
21 proposed resources may contribute to reduce Residential rates, the proposed
22 resources will also preserve reliability, meet customer needs, support economic
23 development in the state and help manage future cost by capturing tax benefits that

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 will no longer be available. Considering these factors together allows the
2 Commission to determine whether the portfolio represents a reasonable and prudent
3 approach to serving customers over time.

4

5 **Q. From a pricing perspective, why should the Commission find that approval of**
6 **PNM's proposed resources are in the public interest?**

7 **A.** Approval of the preferred resource portfolio supports the long-term provision of
8 reliable electric service at reasonable cost. As explained by other witnesses in this
9 case, the combination of renewable generation, storage capability, and dispatchable
10 capacity provides a balanced resource mix. From a ratemaking standpoint,
11 investments that enhance system reliability and cost stability over time promote just
12 and reasonable rates and are therefore consistent with the public interest.

13

14

IV. CONCLUSION

15

16 **Q. Please summarize your testimony and recommendations.**

17 **A.** I recommend that the Commission consider the cost allocation framework and rate
18 impact presented in my testimony as informational analysis intended to assist the
19 Commission in evaluating the preferred resource portfolio. The Company is not
20 requesting approval of final cost recovery mechanisms or specific customer rate
21 adjustments in this proceeding. Instead, PNM will request authorization to recover
22 prudently incurred costs through the appropriate regulatory proceeding in the
23 future, such as a general rate case or other Commission-approved mechanism. The

**DIRECT TESTIMONY
OF JULIO C. AGUIRRE
NMPRC DOCKET NO. 26-0000**_____

1 Company also anticipates requesting the approval of a dedicated large load tariff
2 with a rate structure that will ensure incremental costs associated with serving these
3 customers are fully recovered from the loads that drive them, while protecting other
4 customers. Based on the analysis presented in my testimony, the projected rate
5 impacts for Residential customers associated with the preferred resource portfolio
6 are expected to result in a decrease in customer rates, while also providing long-
7 term benefits such as improved system reliability and an expanded renewable
8 energy supply.

9

10 **Q. Does this conclude your testimony?**

11 A. Yes, it does.

12 //

13 //

14

GCG#535331

15

Education and Professional Qualifications of Julio C. Aguirre

PNM Exhibit JCA-1

Is contained in the following 4 pages.

JULIO C. AGUIRRE

EXPERIENCE AND QUALIFICATIONS

CURRENT POSITION: *Director, Pricing & Customer Strategy.* Public Service Company of New Mexico (PNM)

EDUCATION:

Master of Liberal Arts (ALM), Finance. Harvard University (Extension School).

Master of Arts (MA), Economics, *Specialization in Public Utility Policy & Regulation.* New Mexico State University (NMSU).

Bachelor of Arts (BA), International Economics, Autonomous University of Chihuahua (UACH).

EXPERIENCE:

Program Manager, Rates and Pricing. Grant County PUD. (09/2021-12/2024)

Manager, Rate Development. GridLiance/NextEra Energy Transmission. (12/2020-09/2021)

Senior Rate Analyst, El Paso Electric Co. (12/2018-12/2020)

Lead Pricing Analyst, Public Service Company of New Mexico. (11/2015-12/2018)

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

Regulatory 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. (01/2006-06/2007)

Research Associate, Research Institute for Economic and Technological Development, 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	Public Utilities Commission of Nevada	10-04002

Energy on compliance with the Portfolio Standard for Renewable Energy for Compliance Year 2009.

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

New Mexico Public
Regulation Commission 16-00096-UT

Electric Energy Efficiency Program Plan, Profit Incentive and Revised Rider No. 16.

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

New Mexico Public
Regulation Commission

16-00276-UT

In the Matter of the Application of Public Service Company of New Mexico for Approval of its 2018 Electric Energy Efficiency Program Plan, Profit Incentive and Revised Rider No. 16, pursuant to the NM Public Utility Act, Efficient Use of Energy Act and Energy Efficiency Rule.

New Mexico Public
Regulation Commission

17-00076-UT

In the Matter of the Petition of Public Service Company of New Mexico for Energy Efficiency Disincentive Identification and Removal Mechanism Approvals.

New Mexico Public
Regulation Commission

18-00043-UT

In the Matter of El Paso Electric Company's Application for a Certificate of Public Convenience and Necessity to Construct a Solar Generation/Storage Project at New Mexico State University and for Approval of a Special Rate Contract.

New Mexico Public
Regulation Commission

19-00350-UT

In the Matter of the Application of El Paso Electric Company for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 268

New Mexico Public
Regulation Commission

20-00104-UT

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. 625 (Adopted)

New Mexico Public
Regulation Commission

24-00089-UT

In the Matter of Public Service Company of New Mexico's Application for Approval of An Amended Special Service Contract with Greater Kudu, LLC, Three Purchased Power Agreements Pursuant to 17.9.551 NMAC, Amended Rate No. 36B, Amended Rider No. 47, and Amended Rider No. 49

New Mexico Public
Regulation Commission

25-00048-UT

Illustrative Class Allocation of Preferred Portfolio Revenue Requirement (Test Year 2031)

PNM Exhibit JCA-2

Is contained in the following 1 page.

PNM Exhibit JCA-2 Illustrative Class Allocation of Preferred Portfolio Revenue Requirement (TY 2031)

(A) (B) (C) (D) (E) (F) (G) (H) (I)=Σ(A):(H) (J) (K) (L) (M)=Σ(J):(K)

Line No.	Description	Production-Demand	Production-Energy-Non-Fuel	Transmission-Demand	Distribution-Demand-Subs	Distribution-Demand-Primary	Distribution-Demand-Secondary	Distribution-Customer	Total Non-Fuel	FPPCAC		Rider 47	Total \$ Allocated
										PPA	Fuel		
1	Re-Allocated Rev. Req. 24-00089-UT+ Proj.												
2	FPPCAC w/ TY Allocation Ratios									\$96,032,867	\$143,078,775		
3													
4	1A/1B	\$129,603,885	\$10,075,923	\$37,374,533	\$19,090,126	\$82,339,423	\$38,386,223	\$122,552,817	\$439,422,929	\$23,193,075	\$34,555,218		\$497,171,222
5	Schedule 2A/2B	\$25,116,840	\$3,097,778	\$7,243,071	\$4,422,403	\$19,074,685	\$8,892,522	\$17,758,246	\$85,605,545	\$7,130,562	\$10,623,780		\$103,359,887
6	Schedule 3B/3C/3D/3E/3F	\$47,326,596	\$5,917,222	\$13,647,812	\$6,763,377	\$29,171,760	\$13,599,727	\$5,086,787	\$121,513,281	\$13,620,448	\$20,293,021		\$155,426,749
7	Schedule 4B	\$27,921,904	\$3,220,976	\$8,330,168	\$2,965,858	\$12,792,320	\$0	\$1,259,325	\$56,490,551	\$7,414,144	\$11,046,288		\$74,950,983
8	5B	\$382,683	\$81,435	\$119,342	\$0	\$0	\$0	\$22,305	\$605,766	\$187,451	\$279,282		\$1,072,498
9	Schedule 10A/10B	\$530,634	\$68,574	\$165,811	\$95,921	\$413,725	\$192,877	\$269,859	\$1,737,400	\$157,846	\$235,174		\$2,130,419
10	Schedule 11B	\$2,209,740	\$483,156	\$684,886	\$692,252	\$2,985,820	\$0	\$660,970	\$7,716,824	\$1,112,143	\$1,656,974		\$10,485,941
11	Schedule 15B	\$908,076	\$197,826	\$283,752	\$0	\$0	\$0	\$49,230	\$1,438,883	\$455,361	\$678,440		\$2,572,684
12	Schedule 30B	\$13,757,269	\$2,523,733	\$4,263,924	\$1,683,231	\$0	\$0	\$577,484	\$22,805,641	\$5,809,207	\$8,655,102		\$37,269,949
13	Schedule 33B	\$34,192	\$0	\$10,684	\$7,740	\$0	\$0	\$5,437	\$58,053	\$17,815	\$26,543		\$102,411
14	Schedule 35B	\$5,235,177	\$688,748	\$1,509,695	\$540,592	\$0	\$0	\$128,296	\$8,102,509	\$1,585,382	\$2,362,052		\$12,049,943
15	Schedule 36B	\$0	\$5,272,020	\$21,514,495	\$0	\$0	\$0	\$290,236	\$27,076,751	\$12,135,302	\$18,080,311		\$57,292,364
16	Schedule 6	\$12,495	\$41,692	\$3,603	\$62,779	\$270,780	\$126,236	\$1,029,758	\$1,547,343	\$95,968	\$142,982		\$1,786,293
17	Schedule 20	\$30,512	\$101,599	\$8,799	\$156,610	\$675,489	\$314,909	\$3,396,474	\$4,684,393	\$233,865	\$348,433		\$5,266,691
18	Generic 350 MW	\$37,215,466	\$6,326,587	\$11,628,961	\$0	\$0	\$0	\$290,236	\$55,461,250	\$14,562,736	\$21,696,931		\$91,720,917
19	Generic 200MW SB170	\$21,265,981	\$3,615,193	\$6,645,120	\$0	\$0	\$0	\$290,236	\$31,816,530	\$8,321,564	\$12,398,246		\$52,536,339
20	Total	\$311,551,450	\$41,720,201	\$113,434,656	\$36,473,149	\$147,724,001	\$61,512,494	\$153,667,696	\$866,083,648	\$96,032,867	\$143,078,775	\$0	\$1,105,195,290
21													
22													
23													
24													
25	Preferred Portfolio Costs - Class Allocation												
26	1A/1B	\$29,782,510	\$241,426	\$5,191,686	\$216,283	\$230,327	\$257,869	\$0	\$35,920,102	\$5,570,908	-\$4,100,509		\$37,390,501
27	Schedule 2A/2B	\$5,771,760	\$74,225	\$1,006,133	\$50,104	\$53,357	\$59,738	\$0	\$7,015,317	\$1,712,740	-\$1,260,675		\$7,467,382
28	Schedule 3B/3C/3D/3E/3F	\$10,875,483	\$141,781	\$1,895,814	\$76,626	\$81,602	\$91,360	\$0	\$13,162,665	\$3,271,591	-\$2,408,079		\$14,026,177
29	Schedule 4B	\$6,416,354	\$77,177	\$1,157,141	\$33,602	\$35,784	\$0	\$0	\$7,720,058	\$1,780,855	-\$1,310,812		\$8,190,101
30	5B	\$87,939	\$1,951	\$16,578	\$0	\$0	\$0	\$0	\$106,468	\$45,025	-\$33,141		\$118,352
31	Schedule 10A/10B	\$121,938	\$1,643	\$23,033	\$1,087	\$1,157	\$1,296	\$0	\$150,153	\$37,914	-\$27,907		\$160,160
32	Schedule 11B	\$507,790	\$11,577	\$95,137	\$7,843	\$8,352	\$0	\$0	\$630,790	\$267,133	-\$196,626		\$701,208
33	Schedule 15B	\$208,673	\$4,740	\$39,416	\$0	\$0	\$0	\$0	\$252,829	\$109,376	-\$80,507		\$281,698
34	Schedule 30B	\$3,161,371	\$60,470	\$592,300	\$19,070	\$0	\$0	\$0	\$3,833,213	\$1,395,354	-\$1,027,061		\$4,201,506
35	Schedule 33B	\$7,857	\$185	\$1,484	\$0	\$0	\$0	\$0	\$9,527	\$4,279	-\$3,150		\$10,656
36	Schedule 35B	\$1,203,025	\$16,503	\$209,711	\$6,125	\$0	\$0	\$0	\$1,435,364	\$380,804	-\$280,294		\$1,535,874
37	Schedule 36B*	\$0	\$126,321	\$37,307,565	\$0	\$0	\$0	\$0	\$37,433,886	\$2,914,863	-\$2,145,507	\$111,648,318	\$149,851,560
38	Schedule 6	\$2,871	\$999	\$501	\$711	\$757	\$848	\$0	\$6,687	\$23,051	-\$16,967		\$12,772
39	Schedule 20	\$7,012	\$2,434	\$1,222	\$1,774	\$1,890	\$2,115	\$0	\$16,448	\$56,174	-\$41,347		\$31,274
40	Generic 350 MW	\$64,566,011	\$0	\$25,980,760	\$0	\$0	\$0	\$0	\$90,546,771	\$73,364,638	\$20,841,391		\$184,752,800
41	Generic 200MW SB170	\$27,280,661	\$0	\$9,091,978	\$0	\$0	\$0	\$0	\$36,372,639	\$35,345,194	\$20,841,391		\$92,559,223
42	Total	\$150,001,255	\$761,433	\$82,610,459	\$413,226	\$413,226	\$413,226	\$0	\$234,612,826	\$126,279,900	\$28,750,200	\$111,648,318	\$501,291,244
43	Total Class Allocation												
44	1A/1B	\$159,386,395	\$10,317,349	\$42,566,219	\$19,306,409	\$82,569,750	\$38,644,092	\$122,552,817	\$475,343,031	\$28,763,982	\$30,454,710	\$0	\$534,561,722
45	Schedule 2A/2B	\$30,888,600	\$3,172,003	\$8,249,204	\$4,472,507	\$19,128,043	\$8,952,260	\$17,758,246	\$92,620,862	\$8,843,302	\$9,363,105	\$0	\$110,827,269
46	Schedule 3B/3C/3D/3E/3F	\$58,202,078	\$6,059,003	\$15,543,625	\$6,840,003	\$29,253,362	\$13,691,087	\$5,086,787	\$134,675,946	\$16,892,039	\$17,884,941	\$0	\$169,452,926
47	Schedule 4B	\$34,338,258	\$3,298,153	\$9,487,309	\$2,999,459	\$12,828,104	\$0	\$1,259,325	\$64,210,609	\$9,195,000	\$9,735,476	\$0	\$83,141,084
48	5B	\$470,622	\$83,387	\$135,920	\$0	\$0	\$0	\$22,305	\$712,234	\$232,476	\$246,140	\$0	\$1,190,850
49	Schedule 10A/10B	\$652,571	\$70,217	\$188,843	\$97,008	\$414,882	\$194,172	\$269,859	\$1,887,553	\$195,760	\$207,267	\$0	\$2,290,580
50	Schedule 11B	\$2,717,531	\$494,732	\$780,024	\$700,095	\$2,994,172	\$0	\$660,970	\$8,347,524	\$1,379,276	\$1,460,349	\$0	\$11,187,148
51	Schedule 15B	\$1,116,748	\$202,566	\$323,168	\$0	\$0	\$0	\$49,230	\$1,691,712	\$564,737	\$597,932	\$0	\$2,854,382
52	Schedule 30B	\$16,918,641	\$2,584,203	\$4,856,224	\$1,702,301	\$0	\$0	\$577,484	\$26,638,853	\$7,204,561	\$7,628,041	\$0	\$41,471,455
53	Schedule 33B	\$42,049	\$7,925	\$12,168	\$0	\$0	\$0	\$5,437	\$67,580	\$22,094	\$23,393	\$0	\$113,067
54	Schedule 35B	\$6,438,202	\$705,251	\$1,719,406	\$546,717	\$0	\$0	\$128,296	\$9,537,873	\$1,966,187	\$2,081,758	\$0	\$13,585,817
55	Schedule 36B	\$0	\$5,398,342	\$58,822,060	\$0	\$0	\$0	\$290,236	\$64,510,638	\$15,050,165	\$15,934,804	\$111,648,318	\$207,143,925
56	Schedule 6	\$15,366	\$42,691	\$4,104	\$63,491	\$271,537	\$127,084	\$1,029,758	\$1,554,031	\$119,019	\$126,015	\$0	\$1,799,065
57	Schedule 20	\$37,524	\$104,034	\$10,021	\$158,384	\$677,378	\$317,025	\$3,396,474	\$4,700,840	\$290,038	\$307,086	\$0	\$5,297,965
58	Generic 350 MW	\$101,781,477	\$6,326,587	\$37,609,721	\$0	\$0	\$0	\$290,236	\$146,008,021	\$87,927,374	\$42,538,321	\$0	\$276,743,717
59	Generic 200MW SB170	\$48,546,642	\$3,615,193	\$15,737,098	\$0	\$0	\$0	\$290,236	\$68,189,168	\$43,666,757	\$33,239,637	\$0	\$145,095,562
	Total	\$461,552,705	\$42,481,634	\$196,045,116	\$36,886,375	\$148,137,228	\$61,925,720	\$153,667,696	\$1,100,696,474	\$222,312,767	\$171,828,975	\$111,648,318	\$1,606,486,534

*Note: Also includes allocation of incremental costs allocated to existing customers load segment.

Illustrative Functionalization of Preferred Portfolio Revenue Requirement (Test
Year 2031)

PNM Exhibit JCA-3

Is contained in the following 2 pages.

PNM Exhibit JCA-3 Illustrative Functionalization of Preferred Portfolio Revenue Requirement (TY 2031)

Line No.	(A)	(B)=Σ[(C):(R)]	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1										
2	Total Rev. Req. for Resource Filing (TY 2031)	TOTAL	Schedule 1A/1B	Schedule 2A/2B	Schedule 3B/3C/3D/3E/3F	Schedule 4B	Schedule 5B	Schedule 10A/10B	Schedule 11B	Schedule 15B
3	Production-Demand	\$69,284,449	\$15,603,693	\$3,023,948	\$5,697,898	\$3,361,665	\$46,073	\$63,886	\$266,042	\$109,328
4	Production-Energy-Fuel	\$252,849,618	\$1,470,399	\$452,065	\$863,512	\$470,043	\$11,884	\$10,007	\$70,508	\$28,869
5	Production-Energy-Non-Fuel	\$761,433	\$241,426	\$74,225	\$141,781	\$77,177	\$1,951	\$1,643	\$11,577	\$4,740
6	Storage-Production-Demand	\$80,716,806	\$14,178,816	\$2,747,812	\$5,177,585	\$3,054,689	\$41,866	\$58,052	\$241,748	\$99,345
7	Storage-Transmission-Demand	\$26,225,586	\$4,868,866	\$943,571	\$1,777,932	\$1,085,190	\$15,547	\$21,601	\$89,222	\$36,965
8	Storage-Distribution-Demand-Subs	\$413,226	\$216,283	\$50,104	\$76,626	\$33,602	\$0	\$1,087	\$7,843	\$0
9	Storage-Distribution-Demand-Primary	\$413,226	\$230,327	\$53,357	\$81,602	\$35,784	\$0	\$1,157	\$8,352	\$0
10	Storage-Distribution-Demand-Secondary	\$413,226	\$257,869	\$59,738	\$91,360	\$0	\$0	\$1,296	\$0	\$0
11	Transmission-Demand	\$70,213,674	\$322,820	\$62,562	\$117,882	\$71,951	\$1,031	\$1,432	\$5,916	\$2,451
12	Distribution-Demand-Subs	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
13	Distribution-Demand-Primary	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14	Distribution-Demand-Secondary	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Distribution-Customer-Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
16	Distribution-Customer-Meters	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
17	Distribution-Customer-Meter Reading	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
18	Distribution-Customer-Billing & Collections	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
19	Distribution-Customer-Service & Info	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Distribution-Customer-Other	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	TOTAL REVENUE REQUIREMENTS	\$501,291,244	\$37,390,501	\$7,467,382	\$14,026,177	\$8,190,101	\$118,352	\$160,160	\$701,208	\$281,698
22										
23										
24	24-00089-UT Rev. Req. Allocated using 2031 Class Allocation Ratios	TOTAL	Schedule 1A/1B	Schedule 2A/2B	Schedule 3B/3C/3D/3E/3F	Schedule 4B	Schedule 5B	Schedule 10A/10B	Schedule 11B	Schedule 15B
25	Production-Demand	\$254,523,760	\$105,880,644	\$20,519,348	\$38,663,736	\$22,810,961	\$312,635	\$433,504	\$1,805,260	\$741,858
26	Production-Energy-Fuel	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
27	Production-Energy-Non-Fuel	\$41,720,201	\$10,075,923	\$3,097,778	\$5,917,222	\$3,220,976	\$81,435	\$68,574	\$483,156	\$197,826
28	Storage-Production-Demand	\$57,027,690	\$23,723,241	\$4,597,492	\$8,662,859	\$5,110,943	\$70,048	\$97,129	\$404,480	\$166,218
29	Storage-Transmission-Demand	\$24,582,550	\$8,099,477	\$1,569,654	\$2,957,632	\$1,805,240	\$25,863	\$35,933	\$148,422	\$61,492
30	Storage-Distribution-Demand-Subs	\$1,003,514	\$525,241	\$121,677	\$186,086	\$81,602	\$0	\$2,639	\$19,046	\$0
31	Storage-Distribution-Demand-Primary	\$1,546,749	\$862,138	\$199,722	\$305,444	\$133,942	\$0	\$4,332	\$31,263	\$0
32	Storage-Distribution-Demand-Secondary	\$819,418	\$511,349	\$118,459	\$181,164	\$0	\$0	\$2,569	\$0	\$0
33	Transmission-Demand	\$88,852,106	\$29,275,057	\$5,673,417	\$10,690,179	\$6,524,928	\$93,479	\$129,878	\$536,464	\$222,260
34	Distribution-Demand-Subs	\$35,469,636	\$18,564,884	\$4,300,726	\$6,577,291	\$2,884,256	\$0	\$93,282	\$673,206	\$0
35	Distribution-Demand-Primary	\$146,177,252	\$81,477,285	\$18,874,963	\$28,866,316	\$12,658,378	\$0	\$409,393	\$2,954,556	\$0
36	Distribution-Demand-Secondary	\$60,693,076	\$37,874,874	\$8,774,063	\$13,418,563	\$0	\$0	\$190,307	\$0	\$0
37	Distribution-Customer-Services	\$19,889,750	\$18,152,448	\$1,737,303	\$0	\$0	\$0	\$0	\$0	\$0
38	Distribution-Customer-Meters	\$29,187,791	\$18,818,124	\$6,216,129	\$2,802,108	\$583,883	\$3,497	\$204,608	\$524,477	\$3,497
39	Distribution-Customer-Meter Reading	\$28,498,567	\$25,440,698	\$2,807,063	\$218,151	\$8,516	\$51	\$15,929	\$7,649	\$51
40	Distribution-Customer-Billing & Collections	\$41,334,128	\$37,124,280	\$3,766,918	\$368,262	\$42,772	\$67	\$21,048	\$10,107	\$67
41	Distribution-Customer-Service & Info	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
42	Distribution-Customer-Other	\$34,757,460	\$23,017,267	\$3,230,833	\$1,698,266	\$624,155	\$18,690	\$28,274	\$118,737	\$45,615
43	TOTAL NON-FUEL REVENUE REQUIREMENTS	\$866,083,648	\$439,422,929	\$85,605,545	\$121,513,281	\$56,490,551	\$605,766	\$1,737,400	\$7,716,824	\$1,438,883
44										
45										
46	24-00089-UT Cost of Service Study Rev. Req.	TOTAL	Schedule 1A/1B	Schedule 2A/2B	Schedule 3B/3C/3D/3E/3F	Schedule 4	Schedule 5	Schedule 10A/10B	Schedule 11	Schedule 15
47	Production-Demand	\$254,523,760	\$131,930,783	\$26,901,993	\$49,882,428	\$21,061,882	\$487,826	\$584,098	\$2,594,506	\$1,143,950
48	Production-Energy-Fuel	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
49	Production-Energy-Non-Fuel	\$41,720,201	\$15,268,036	\$4,545,175	\$8,855,430	\$4,452,315	\$134,581	\$105,981	\$809,865	\$328,904
50	Storage-Production-Demand	\$57,027,690	\$29,559,943	\$6,027,565	\$11,176,480	\$4,719,050	\$109,301	\$130,871	\$581,316	\$256,309
51	Storage-Transmission-Demand	\$24,582,550	\$11,216,438	\$2,287,143	\$4,240,884	\$1,835,971	\$44,262	\$49,659	\$232,249	\$95,357
52	Storage-Distribution-Demand-Subs	\$1,003,514	\$484,495	\$126,494	\$203,858	\$89,685	\$0	\$2,831	\$21,687	\$0
53	Storage-Distribution-Demand-Primary	\$1,546,749	\$801,581	\$209,280	\$337,277	\$148,381	\$0	\$4,684	\$35,880	\$0
54	Storage-Distribution-Demand-Secondary	\$819,418	\$482,081	\$125,864	\$202,843	\$0	\$0	\$2,817	\$0	\$0
55	Transmission-Demand	\$88,852,106	\$40,541,119	\$8,266,736	\$15,328,412	\$6,636,003	\$159,983	\$179,488	\$839,450	\$344,662
56	Distribution-Demand-Subs	\$35,469,636	\$17,124,677	\$4,470,971	\$7,205,448	\$3,169,947	\$0	\$100,066	\$766,520	\$0
57	Distribution-Demand-Primary	\$146,177,252	\$75,754,339	\$19,778,211	\$31,874,702	\$14,022,876	\$0	\$442,660	\$3,390,852	\$0
58	Distribution-Demand-Secondary	\$60,693,076	\$35,707,036	\$9,322,519	\$15,024,237	\$0	\$0	\$208,649	\$0	\$0
59	Distribution-Customer-Services	\$19,889,750	\$18,152,448	\$1,737,303	\$0	\$0	\$0	\$0	\$0	\$0
60	Distribution-Customer-Meters	\$29,187,791	\$18,822,634	\$6,217,619	\$2,802,780	\$584,023	\$3,497	\$204,657	\$524,603	\$3,497
61	Distribution-Customer-Meter Reading	\$28,498,567	\$25,440,789	\$2,807,073	\$218,152	\$8,516	\$51	\$15,929	\$7,649	\$51
62	Distribution-Customer-Billing & Collections	\$41,334,128	\$37,124,401	\$3,766,931	\$368,263	\$42,772	\$67	\$21,048	\$10,107	\$67
63	Distribution-Customer-Service & Info	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
64	Distribution-Customer-Other	\$34,757,460	\$23,403,248	\$3,285,011	\$1,726,745	\$634,622	\$19,004	\$28,748	\$120,728	\$46,380
65	TOTAL NON-FUEL REVENUE REQUIREMENTS	\$866,083,648	\$481,814,049	\$99,875,886	\$149,447,937	\$57,406,041	\$958,571	\$2,082,186	\$9,935,411	\$2,219,178

Illustrative Rate Impact on Residential Customers of Preferred Portfolio Revenue Requirement (Test Year 2031)

PNM Exhibit JCA-4

Is contained in the following 1 page.

PNM Exhibit JCA-4 Estimated Revenue/Rate Impact of Preferred Portfolio for the Residential Class (TY 2031)

Line No.	(A)	(B)	(C)	(D)	(E)=(C)+(D)	(F)=[(E)/(B)]-1
		Current 24-00089-UT Allocated Costs	Total Projected Revenue Requirement (TY 2031) Existing Reallocated Costs	Incremental Cost	Total	
1						
2	DEMAND COMPONENTS	\$ 343,602,493	\$ 306,794,189	\$ 35,678,676	\$ 342,472,865	-0.33%
3	DEMAND PRODUCTION	\$ 161,490,726	\$ 129,603,885	\$ 29,782,510	\$ 159,386,395	
4	DEMAND TRANSMISSION	\$ 51,757,557	\$ 37,374,533	\$ 5,191,686	\$ 42,566,219	
5	DEMAND SUBSTATION	\$ 17,609,172	\$ 19,090,126	\$ 216,283	\$ 19,306,409	
6	DEMAND DISTRIBUTION PRIMARY	\$ 76,555,920	\$ 82,339,423	\$ 230,327	\$ 82,569,750	
7	DEMAND DISTRIBUTION SECONDARY	\$ 36,189,118	\$ 38,386,223	\$ 257,869	\$ 38,644,092	
8						
9	ENERGY COMPONENTS	\$ 83,579,726	\$ 67,824,216	\$ 1,711,825	\$ 69,536,041	-16.80%
10	FPPCAC*	\$ 68,311,690	\$ 57,748,293	\$ 1,470,399	\$ 59,218,692	
11	ENERGY NON FUEL	\$ 15,268,036	\$ 10,075,923	\$ 241,426	\$ 10,317,349	
12						
13	CUSTOMER COMPONENTS**	\$ 122,943,520	\$ 122,552,817	\$ -	\$ 122,552,817	-0.32%
14	CUSTOMER SERVICES	\$ 18,152,448	\$ 18,152,448	\$ -	\$ 18,152,448	
15	CUSTOMER METER	\$ 18,822,634	\$ 18,818,124	\$ -	\$ 18,818,124	
16	CUSTOMER METER READING	\$ 25,440,789	\$ 25,440,698	\$ -	\$ 25,440,698	
17	CUSTOMER BILLING & COLLECTION	\$ 37,124,401	\$ 37,124,280	\$ -	\$ 37,124,280	
18	CUSTOMER SERVICE & INFORMATION	\$ -	\$ -	\$ -	\$ -	
19	CUSTOMER OTHER	\$ 23,403,248	\$ 23,017,267	\$ -	\$ 23,017,267	
20						
21						
22	TOTAL NON-FUEL REVENUE REQUIREMENT	\$ 550,125,739	\$ 497,171,222	\$ 37,390,501	\$ 534,561,722	-2.83%
23						
24	<i>*Revenue Requirement for 2031 reflects additional projected changes in fuel and purchased power costs that were not included in Case No. 24-00089-UT.</i>					
25	<i>** Assumes no increase to existing customer-related costs</i>					
26						
27						
28	kWh Total	3,244,185,240	3,244,185,240	426,209,577	3,670,394,817	13.14%
29						
30	Average Non-Fuel Rate	\$ 0.148516	\$ 0.135449	\$ 0.084278	\$ 0.129507	-12.80%
31	Average FPPCAC	\$ 0.021057	\$ 0.017801	\$ 0.003450	\$ 0.016134	-23.38%
32	Total Non-Fuel+FPPCAC Rate	\$ <u>0.169573</u>	\$ 0.153250	\$ 0.087728	\$ <u>0.145641</u>	-14.11%
33						

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE)
COMPANY OF NEW MEXICO’S APPLICATION)
FOR APPROVAL OF PURCHASED POWER)
AGREEMENTS, ENERGY STORAGE)
AGREEMENTS, AND CERTIFICATE OF PUBLIC)
CONVENIENCE AND NECESSITY FOR 2029-2032) **Docket No. 26-0000** _____
SYSTEM RESOURCES AND THE ABANDONMENT)
OF THE FOUR CORNERS POWER PLANT)
)
PUBLIC SERVICE COMPANY OF NEW MEXICO,)
)
Applicant.)
_____)

AFFIDAVIT

STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

JULIO C. AGUIRRE, Director, Pricing and Customer Strategy, PNMR Services Company, 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.

DATED this 29th day of May, 2026.

/s/ Julio C. Aguirre
JULIO C. AGUIRRE

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE)
COMPANY OF NEW MEXICO'S APPLICATION)
FOR APPROVAL OF PURCHASED POWER)
AGREEMENTS, ENERGY STORAGE)
AGREEMENTS, AND CERTIFICATE OF PUBLIC)
CONVENIENCE AND NECESSITY FOR 2029-2032) Docket No. 26-0000 ____
SYSTEM RESOURCES AND THE ABANDONMENT)
OF THE FOUR CORNERS POWER PLANT)
)
PUBLIC SERVICE COMPANY OF NEW MEXICO,)
)
Applicant.)
)
)

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the **Public Service Company of New Mexico's Application for Approval of Purchased Power Agreements, Energy Storage Agreements, and Certificate of Public Convenience and Necessity for 2029-2032 System Resources and the Abandonment of the Four Corners Power Plant** was emailed to parties listed below on May 29, 2026:

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Dated this 29th day of May, 2026.

By: /s/Lisa Contreras
Lisa Contreras, Senior Manager
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Public Service Company of New Mexico

GCG#535318