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. 667	)	**Docket No. 26-0000XXX**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

DIRECT TESTIMONY

OF

JULIO C. AGUIRRE

November 24, 2026

NMPRC DOCKET NO. 26-0000XXX
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PUBLIC SERVICE COMPANY OF NEW MEXICO

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SPONSORED EXHIBITS

PNM Exhibit JCA-1	Statement of Qualifications
PNM Exhibit JCA-2	2015 Comparison of Transmission Loading and PNM Firm Load
PNM Exhibit JCA-3	2022-2025 Comparison of Transmission Loading and PNM Firm Load

PNM Exhibit JCA-4	Incremental Cost Test Formula and Rate Derivation for Data Center Large Power Schedule 37B
PNM Exhibit JCA-5	Derivation of Non-Fuel Rates for Large Power at Transmission Service Schedule 38B
PNM Exhibit JCA-6	Large Power at Transmission Service Schedule 38B Tariff
Affirmation	

ACRONYM /ABBREVIATION	DESCRIPTION
General Abbreviations	
2022 Rate Case	NMPRC Case No. 22-00270-UT
2024 Rate Case	NMPRC Case No. 24-00089-UT
3S1W 4CP	3 Summer / 1 Winter 4 Coincident Peak allocation method
AMI	Advanced Metering Infrastructure
Commission or NMPRC	New Mexico Public Regulation Commission
ESA	Energy Storage Agreement
kWh	kilowatt hour
kW	kilowatt
NNAI	No Net Adverse Impact
PNM or Company	Public Service Company of New Mexico
PPA	Purchased Power Agreement
PRAC	Pricing Advisory Committee
SSC	Third Amended and Restated Special Service Contract (December 18, 2025), approved in Case No. 25-00048-UT
TOD or TOD Pilot	Time-of-Day Pilot rate approved in NMPRC Case No. 22-00270-UT
TOU	Time-of-Use

ACRONYM /ABBREVIATION	DESCRIPTION
Abbreviations of Rate Schedules	
Residential Schedule 1A	Rate Schedule 1A – Residential Service
Residential Schedule 1B	Rate Schedule 1B – Residential Service Time-of-Day
Small Power Schedule 2A	Rate Schedule 2A – Small Power Service, which is available for commercial, business, professional, small industrial loads, and shared residential wells.
Small Power Schedule 2B	Rate Schedule 2B – Small Power Service Time-of-Day
General Power Schedule 3B	Rate Schedule 3B – General Power Service – Time-of-Use is available to all customers who use the Company's standard service for general power, lighting, and/or water and sewage pumping services.
General Power Schedule 3C	Rate Schedule 3C – General Power Service (Low Load Factor) – Time-of-Use
General Power Schedule 3D	Rate Schedule 3D – General Power Service – Time-of-Use service is available to municipalities and counties that use the Company's standard service for general power, lighting, and/or water and sewage pumping services.
General Power Schedule 3E	Rate Schedule 3E – General Power Service (Low Load Factor) is available to municipalities and counties that use the Company's standard service for general power, lighting, and/or water and sewage pumping services.

ACRONYM /ABBREVIATION	DESCRIPTION
General Power Schedule 3F	Rate Schedule 3F – Non-Residential Charging Station – Pilot is available to metered electric usage by non-residential electric vehicle charging stations.
Large Power Schedule 4B	Rate Schedule 4B – Large Power Service – Time-of-Use is available to all customers who use the Company's standard service for large power with a minimum demand of 500 kW.
Large Service Schedule 5B	Rate Schedule 5B – Large Service >= 8,000 kW Minimum is available to retail customers who have a minimum demand of 8,000 kW and take service directly from PNM's transmission system at 115 kV or the Company's primary distribution voltage of 69 kV, 46 kV or 34.5 kV.
Private Lighting Schedule 6	Rate Schedule 6 – Private Area Lighting Service is provided to private area lighting under agreement for lights installed before February 23, 1991.
Irrigation Schedule10A	Rate Schedule 10A – Irrigation Service is available only for irrigation pumping installations of not less than 5 HP and where service is used to irrigate three or more acres of land used principally for agricultural purposes.
Irrigation Schedule 10B	Rate Schedule 10B – Irrigation Service Time-of-Use
Water and Sewage Schedule 11B	Rate Schedule 11B – Water and Sewage Pumping Service – Time-of-Use is available to all municipal and private corporations for municipal water and sewage pumping

ACRONYM /ABBREVIATION	DESCRIPTION
	purposes where the combined load is greater than 2,500 kW.
Universities Schedule 15B	Rate Schedule 15B – Large Service for Public Universities >= 8,000 kW is available to public universities, with a minimum contract demand of 8,000 kW, that operate customer-owned generation, requests full requirements service from the Company commensurate with the customer's normal electric service requirements and takes service directly from PNM's transmission system at 115 kV.
Streetlighting Schedule 20	Rate Schedule 20 – Integrated System Streetlighting and Floodlighting Service is available to any municipal corporation or other political subdivisions within the State of New Mexico.
Manufacturing Schedule 30B	Rate Schedule 30B – Large Service for Manufacturing >= 30,000 kW is available to any manufacturing customer who has minimum demand of 30,000 kW and load factor of at least 80% and takes service at PNM's primary distribution voltage.
Station Power Schedule 33B	Rate Schedule 33B – Large Service for Station Power – Time-of-Use is available only to electric generation station customers or energy storage systems who require a minimum demand for electric service of no less than 50 kW per month.
Large Power Schedule 35B	Rate Schedule 35B – Large Power Service >= 3,000 kW Time-of-Use is available to customer who has a minimum demand of 3,000 kW but less than 30,000 kW, a load factor of at least 75%, and takes service directly from a Company-owned substation.

ACRONYM /ABBREVIATION	DESCRIPTION
Special Service Rate Schedule 36B	Special Service Rate – Renewable Energy Resources is a special service rate that, combined with the Green Energy Rider (Rider No. 47) and the Production Cost Allocation Rider (Rider No. 49), is available to eligible customers who wish to have the Company acquire renewable energy resources in an amount equal to some or all of the customer's electric utility service requirements and who enter into a Special Service Contract approved by the Commission.
Data Center Large Power Schedule 37B	Rate Schedule 37B is for large load Data Center customers whose Electric Service Agreement states it shall take Service pursuant to this Schedule for a defined amount of Contract Capacity commensurate with the Customer's normal requirements but in no case less than 30,000 kilowatts.
Large Power at Transmission Schedule 38B	Rate Schedule 38B is available to any retail customer who contracts for a definite capacity commensurate with the customer's normal requirements but in no case less than 30,000 kW of capacity and who takes service directly from PNM's transmission system at 115 kV.
Rider No. 23 or FPPCAC	Rider No. 23 – Fuel and Purchased Power Cost Adjustment Clause.
Rider No. 45	Economic Development Rider ("EDR") is a discount available to customers receiving service under Rate Schedule 4B; Rate Schedule 5B; Rate Schedule 30B; and Rate Schedule 35B. The EDR discount is applied

ACRONYM /ABBREVIATION	DESCRIPTION
	to reduce the effective demand charge otherwise applicable for the rate Schedule under which the customer is receiving service.
Rider No. 47	Rider No. 47 – Green Energy Rider specifies that the Rate Schedule 36B customer will pay for the total costs of the acquired renewable resources under this rider.
Rider No. 49	Rider No. 49 – Production Cost Allocation Rider provides for recovery of under-collected production costs from an applicable customer pursuant to the terms and conditions of the Special Service Contract. This rider shall apply to all customers taking service under Special Service Rate Schedule 36B and Rider No. 47.

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

I. INTRODUCTION AND PURPOSE

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

A. My name is Julio C. Aguirre. I am the Director of Pricing and Customer Strategy for Public Service Company of New Mexico ("PNM" or "Company"). My business address is 414 Silver Avenue, SW, Albuquerque, New Mexico 87102. A description of my position and background is included in PNM Exhibit JCA-1. The exhibit also includes a list of cases in which I have provided testimony at the New Mexico Public Regulation Commission ("Commission" or "NMPRC").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of PNM.

Q. What is the purpose of your direct testimony in this docket?

A. The purpose of my testimony is to present and support PNM's ratemaking process, including the class cost-of-service, revenue allocation, and some of the Company's rate design proposals in this case. Specifically, my testimony addresses:

i. PNM's status and progress of its Modern Rate Design Strategy;

ii. Proposed changes in the class cost-of-service study, including new production and transmission cost allocation methodologies;

iii. PNM's proposed revenue allocation and banding among customer classes;

iv. Changes to the residential rate design proposed in this case, including proposed changes to residential rates and programs;

v. The proposed rate design for new large loads, including data centers and other large transmission-level customers;

vi. The NNAI standard applicable to Special Service Rate Schedule 36B; and

vii. Proposed rates and charges for some of PNM's other retail customer classes.

II. PROGRESS ON PNM'S TRANSITION TO ITS MODERN RATE DESIGN

Q. When did PNM first introduce the Modern Rate Design Strategy?

A. In PNM's last two rate cases, Case No. 22-00270-UT ("2022 Rate Case") and Case No. 24-00089-UT ("2024 Rate Case"), PNM discussed the need for the Company to start adopting new pricing structures to align with the increased renewable resources on PNM's system. Modern rate design and pricing structures need to reflect the intermittent nature of these resources, including proper cost allocation that reflects how these resources are planned and utilized to meet customers' demand and energy requirements. Furthermore, a modern rate design sends the appropriate price signals to incentivize customers to use energy efficiently. PNM calls this its "Modern Rate Design Strategy."

Q. What are the goals of PNM's Modern Rate Design Strategy?

A. Consistent with the 2022 Rate Case and, most recently, the 2024 Rate Case, PNM's Modern Rate Design Strategy continues to evolve, using transparency and stakeholder engagement, to improve the alignment of rates with the evolving costs and electric grid. PNM's Modern Rate Design Strategy provides a framework for PNM to modernize its rate offerings over time in a thoughtful and gradual manner, taking into consideration changes in the electric system, customer needs and expectations, technological advancements, and PNM's ongoing transition toward a carbon-free future. The Company's strategy establishes the overall direction for evaluating and developing rate design changes as PNM's system and customers' use of electricity continue to evolve, while allowing PNM to incorporate lessons learned through implementation and customer and stakeholder feedback into future rate design proposals.

Q. What progress has PNM made toward the Modern Rate Design Strategy since its last rate case?

A. PNM has continued to advance its Modern Rate Design Strategy through stakeholder engagement, evaluation of its current rate design, development of alternative cost allocation methodologies, and review of pricing structures needed to support an evolving electric grid. A central component of this effort has been the ongoing work conducted through the Pricing Advisory Committee ("PRAC"),

which has served as the primary forum for discussion and collaboration among PNM, Commission Staff, intervenors, and other interested stakeholders.

Q. Please describe the role the PRAC has played since the last rate case.

A. Under Paragraph 28 of the stipulation approved in PNM's 2024 Rate Case, the parties agreed that PRAC would continue its collaborative work on functionalization, classification, allocation methodologies, and rate design approaches. Since the conclusion of that case, the PRAC has met regularly to discuss key rate design issues and evaluate potential reforms needed to support PNM's goal of advancing and modernizing its rate design. Consistent with its purpose, the PRAC has provided stakeholders with a transparent forum to review data, evaluate alternative methodologies, and provide feedback regarding potential future changes to cost allocation and rate design.

Q. What progress has been made with respect to cost allocation methodologies?

A. One of the primary areas of focus since 2024 has been continued evaluation of production and transmission cost allocation methodologies and whether existing allocators appropriately reflect how PNM plans and operates its electric system and how customers use and benefit from it. During multiple PRAC meetings, PNM presented information regarding the changing operating characteristics of the system as increasing levels of renewable generation and energy storage resources are added to the portfolio. Some of the discussions focused on whether existing

allocation approaches based on a few historical or projected system peaks continue to reflect cost causation or whether alternative methodologies may more accurately capture how to allocate costs based on a customer class's demand and energy requirements.

Q. Did the PRAC reach consensus on the appropriate generation and transmission cost allocation methodologies to be used in this docket?

A. No. While the PRAC held extensive discussions regarding alternative cost allocation methodologies, and a subcommittee within PRAC was formed to debate this issue in greater detail, stakeholders did not reach consensus on a single approach. Nevertheless, in PNM's view, the discussions demonstrated that the way the system is planned and operated has evolved with the addition of renewable resources, energy storage, and changing load patterns. As a result, PNM determined it was appropriate to move forward with alternative allocation, which better reflects current planning and operational practices and more accurately aligns cost allocations with the drivers of those costs. These specific cost allocation proposals, specifically for production and transmission costs, are discussed later in my testimony, in Section IV.

Q. What progress has been made regarding time-varying rates and pricing options?

A. At the PRAC meetings, PNM has also continued to discuss the role of time-varying pricing as a key component of its Modern Rate Design Strategy. As PNM obtains additional information regarding customer usage patterns through its ongoing Time-of-Day Pilot ("TOD Pilot" or "Pilot"), it is engaging stakeholders to evaluate how it can make time-varying rates more effective or accessible to customers. PNM still believes that a default TOD rate will effectuate the Company's long-term objective of developing rate structures that encourage economically efficient energy consumption while providing customers with meaningful opportunities to manage their electric bills.

Q. How do the rate design proposals in this case support PNM's transition to default TOD rates?

A. As outlined recently in PNM's Second Annual Grid Modernization Review (Docket No. 26-0000069, "Grid Mod Review"), the transition to default TOD rates is a multi-step process that requires changes to rate design, customer education and advanced metering capabilities. The Roadmap to Default TOD ("Roadmap"), as outlined extensively in the Direct Testimony of Heidi M. Pitts in PNM's Grid Mod Review,[1] recognizes that rates must gradually evolve to better reflect how costs are incurred and how customers use the system throughout the day. The proposals in this proceeding are consistent with that Roadmap. By updating cost allocations and moving rates to better reflect cost causation, PNM is establishing the foundation

[1] Docket No. 26-0000069, Direct Testimony of Heidi M. Pitts Ph.D. (Apr. 10, 2026), pp. 36-52.

needed for future default TOD rate implementation, particularly for residential customers. While this proceeding does not yet propose default TOD rates, it advances the rate design principles needed to support that long-term objective.

Q. What has the PRAC identified as key considerations related to affordability and residential rate design?

A. Through the PRAC process, stakeholders have discussed customer affordability as an important consideration in the rate making process. Consistent with those discussions, PNM is proposing a Low Income Rate Program in this docket to provide bill assistance to qualifying customers. In PNM's view, this targeted approach addresses affordability concerns while allowing the broader stakeholder process to continue evaluating longer-term rate design issues, including cost allocation, rate structures, cost-based rates and different pricing options consistent with the Modern Rate Design Strategy.

Q. In this docket, PNM is proposing two new rate offerings targeted at large-load customers. Please describe these proposals.

A. In addition to the rate design proposals discussed above, PNM is proposing new rate offerings designed specifically to serve large-load customers. These proposals include a tariff focused on the unique risks of serving large data center customers. Another large-load rate offering focuses on manufacturing or loads with significant electric power requirements. Collectively, these new offerings are intended to

ensure that the costs associated with serving new large loads are appropriately allocated and recovered, avoiding undue cost burdens or risks being shifted to existing customers, while also supporting economic development opportunities within New Mexico.

Q. How do these large-load proposals fit within PNM's broader Modern Rate Design Strategy?

A. PNM's Modern Rate Design Strategy is centered on improving allocation of cost causation, transparency, and economic efficiency with appropriate price signals. The proposed large-load tariffs are consistent with these principles because they create rate structures that better reflect the costs, benefits, and risks associated with serving these customer loads and, at the same time, they position PNM's service territory to participate in economic growth opportunities—all while ensuring appropriate protections for existing customers.

Q. Is PNM proposing any changes related to Community Solar cost recovery in this case?

A. Yes. PNM is proposing to recover the regulatory asset associated with Community Solar Bill Credits through base rates. However, PNM is not proposing a separate rate or special recovery mechanism for this regulatory asset. PNM witnesses Alaric J. Babej and Reina N. Gutierrez discuss the details of this proposal in their direct testimony in this case.

Q. Is PNM proposing to modify the Community Solar Bill Credits established by the Commission?

A. Yes. PNM is proposing to update the Community Solar Bill Credits by calculating revised Fixed Community Solar Program Credit Rates based on the results of the class cost of service study presented in this case. The calculated Community Solar Bill Credit calculations for each class are provided in the Direct Testimony of PNM witness Cynthia A. Menhorn.

Q. What are PNM's overall rate design objectives in this filing?

A. The rate design proposals presented in this case are intended to advance PNM's broader Modern Rate Design Strategy and continue supporting the transition to a cleaner electric system. PNM's objectives focus on improving the alignment of rates with cost causation, enhancing transparency in how costs are recovered, providing more economically efficient price signals to customers, and ensuring that rates reflect the evolving way the electric system is planned and operated.

In addition, PNM's proposals seek to provide customers with more access to rate options that accommodate evolving technologies and changing customer needs, while maintaining appropriate protections for existing customers. The proposals are also intended to support long-term affordability and promote economic development opportunities within New Mexico. Collectively, the rate design proposals in this case represent incremental steps toward a modernized rate

framework that better aligns customer rates with the costs, benefits, and operational realities of the electric grid and supports New Mexico's transition to a carbon-free electric system.

III. ONGOING STAKEHOLDER ENGAGEMENT WITH THE PRAC

Q. Did the PRAC process end after the conclusion of the 2024 Rate Case?

A. No. The PRAC process is ongoing and remains an important component of PNM's efforts to advance its Modern Rate Design Strategy. While the 2024 Rate Case represented an important step in that process, there is still substantial work to be done on a variety of rate design issues. The PRAC can continue providing a valuable forum for collaboration and discussion among PNM and stakeholders, allowing parties to explore proposals, exchange perspectives, and develop a better understanding of complex rate design concepts before they are presented in a rate case. Given the value created for stakeholders and the Company, PNM intends to continue the PRAC meetings after this proceeding concludes.

Q. Was the PRAC involved in developing any proposals for this rate case?

A. Yes. While the PRAC did not reach consensus on many issues addressed in this case, it served as an important forum for stakeholder discussion and feedback regarding a variety of rate design and cost allocation topics. The proposals presented in this case were informed by discussions through the PRAC process. Although PNM exercised its own judgment in developing the specific proposals

presented in this filing, stakeholder input received through the PRAC helped inform PNM's evaluation of potential rate design changes.

Q. How extensive has PNM's stakeholder engagement through the PRAC been since the last rate case?

A. Since the conclusion of the 2024 Rate Case, PNM has held a series of PRAC meetings focused on evaluating potential rate design, cost allocation, affordability, distributed generation, and pricing policy issues. PNM conducted meetings on August 19, 2025; September 9, 2025; December 16, 2025; January 20, 2026; March 31, 2026; May 12, 2026; June 23, 2026; and August 17, 2026.[2] Topics discussed during these meetings included production and transmission cost allocation methodologies, low income rates, TOD pricing, default TOD implementation, distributed generation and net metering, customer affordability, community solar-related issues, and large-load tariff concepts. These discussions reflect the PRAC's role as PNM's primary stakeholder forum for evaluating and developing rate design proposals and policy concepts.

[2] Following this filing, PNM intends to reconvene the PRAC to provide an overview of the proposals included in this case. This discussion will not limit any party's ability to pursue formal discovery through the litigation process.

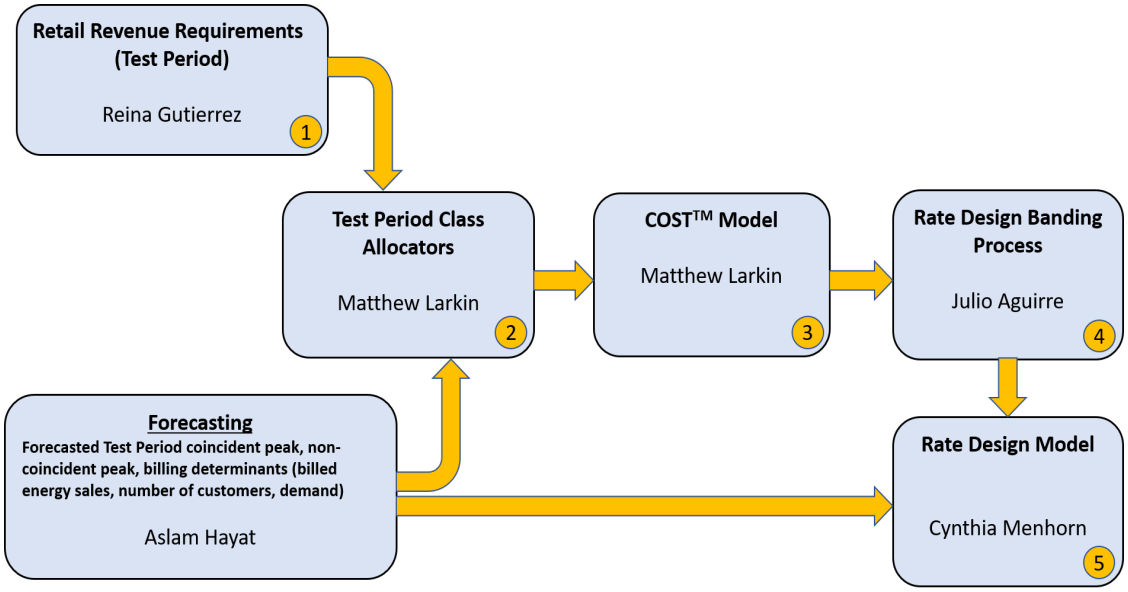
IV. CHANGES TO COST ALLOCATIONS AND BANDING

A. Overview of the Rate Making Process

Q. What is the process that PNM undertakes to develop rates?

A. To develop rates, PNM must convert the system-level revenue requirements, as developed by PNM witness Reina N. Gutierrez, into individual retail rates. This conversion process involves a series of steps that include: (1) starting with the total Company retail revenue requirements for the Test Period; (2) developing Test Period class allocators to allocate costs among PNM's customer classes; (3) applying the COST™ Model using the allocators to allocate production, transmission, distribution and other costs to determine the revenue requirements by customer class; (4) designing and applying banding to the class revenue requirement outputs from the COST™ Model to take into account gradualism in assigning full cost responsibility among the customer classes; and (5) using the Rate Design Model to determine the individual rate components by applying the Test Period billing determinants to the class-level revenue requirements after banding. Figure JCA-1 below depicts the steps described above. As shown in Figure JCA-1, Rate Design Process, I sponsor Step 4. PNM witness Gutierrez sponsors Step 1, and PNM witness Matthew T. Larkin sponsors Steps 2 and 3. Forecasting is conducted by PNM witness Aslam T. Hayat. Finally, PNM witness Menhorn sponsors Step 5.

Figure JCA-1
Rate Design Process



Q. For Step 1 in PNM Figure JCA-1, who sponsors the determination of PNM's retail revenue requirement?

A. As mentioned above, PNM witness Gutierrez provides PNM retail revenue requirements for the Test Period.

Q. Regarding Step 2 in PNM Figure JCA-1, how does PNM derive the class allocators?

A. For all customer classes, PNM witness Hayat provides data on forecasted Test Period coincident peak, forecasted Test Period non-coincident peak, forecasted Test Period billed energy sales, and forecasted Test Period number of customers. PNM witness Larkin uses this data to develop class allocators. For certain customer classes, PNM receives a load forecast directly from the customer.

Q. Once calculated, how are the class allocators used?

A. These allocators are used to allocate production, transmission and distribution revenue requirements to various rate schedules in the COST™ Model.

Q. Please describe Step 3 in PNM Figure JCA-1 regarding application of the COST™ Model.

A. The costs associated with PNM's revenue requirement are input into the COST™ Model. Within the COST™ Model, costs are functionalized, classified and allocated to the different customer classes. The final output from the COST™ Model is the Test Period revenue requirement for each customer class. PNM witness Larkin supports this step and sponsors the COST™ Model.

Q. Please briefly describe the banding process, which is Step 4 of the rate design process shown in PNM Figure JCA-1.

A. The non-fuel revenue requirement for the Test Period, an output of the COST™ Model, is banded to ensure the Company's resulting rate design supports a reasonable and moderate step toward full cost recovery by class. Banding, which is a method of limiting the customer class revenue requirement increase to a given percentage above or below the average system impact, puts into effect the principle of rate gradualism discussed earlier. I support PNM's proposed banding process.

Q. How are the Test Period billing determinants derived?

A. Test Period billing determinants are sponsored by PNM witness Hayat.

Q. How does PNM develop its actual rates using the Rate Design Model, represented by Step 5 in the rate design process shown in figure JCA-1?

A. The Rate Design Model's key function is to convert the Test Period revenue requirement for each customer class after banding into the individual rate elements (e.g., customer, demand, and energy charges) found in PNM's tariffs. The Rate Design Model (PNM Exhibit CAM-2) derives each of these rate elements using the Test Period billing determinants, such that these rate elements total an amount that recovers the Company's proposed revenue requirement for the Test Period for each customer class. PNM witness Menhorn sponsors the Company's Rate Design Model, and the proof of revenue (Rule 530 Schedule O-2) that results from the proposed rates.

A. PROPOSED ALLOCATION OF PRODUCTION-RELATED COSTS

Q. What production cost allocation methodology is PNM proposing in this rate case?

A. PNM is proposing Commission approval of a modified coincident peak ("CP") allocator, referred to in my testimony as a "CP-Risk Hour Method". The proposed allocator incorporates the four CP hours reflected in the allocation methodology approved in PNM's last rate cases, or the 3-Summer/1-Winter CP ("3S1W CP")

hours, combined with 10 additional hours representing the Test Period hours with the highest projected Loss of Load Hours ("LOLH") observed during five (5) of the months included in the Test Period. By incorporating coincident peak conditions and the hours associated with elevated reliability risk, the proposed methodology is intended to better align the allocation of production-related costs with the conditions that drive the need for production capacity and system resources to serve customers' loads.

Q. What is a Loss of Load Hour or LOLH?

A. A Loss of Load Hour, or "LOLH," represents an hour in the Test Period in which the electric system is projected to experience a risk that available production resources may be insufficient to meet customer demand. The LOLH value represents the probability that, during a particular hour, available production resources will be insufficient to meet customer demand. A higher LOLH value therefore indicates a greater projected reliability risk during that hour. LOLH hours are derived from PNM's resource adequacy modeling by evaluating customer demand and available resources across a wide range of conditions. Those reliability risks inform resource planning decisions, including the need for capacity additions and other resources necessary to maintain system reliability. Thus, incorporating the hours with the highest projected LOLH into the allocation of production-related costs helps capture the need for generation capacity to maintain reliability during higher-risk periods.

Q. Why is PNM proposing to incorporate LOLH hours, also called risk hours, into the production cost allocation methodology?

A. The addition of LOLH hours is intended to better recognize the periods in which the system experiences the greatest projected reliability risk in the Test Period. A traditional coincident peak methodology focuses primarily on customer demand during a limited number of system peak hours. However, as PNM's resource portfolio and system conditions evolve, particularly with the addition of more renewable energy generation, the hours that present the greatest reliability challenges may not necessarily coincide with those traditional peak hours.

Q. How does incorporating risk hours into the production cost allocation methodology improve cost causation?

A. From a cost-causation perspective, considering LOLH hours recognizes that the need for production resources is driven not only by the magnitude of peak demand, but also by when that demand occurs during certain system reliability conditions. Consistent with that principle, customers whose loads contribute to system requirements during higher-risk hours should bear an appropriate share of the costs of the resources needed to reliably serve those requirements. Therefore, incorporating LOLH hours into the allocation methodology more closely aligns cost responsibility with the factors that drive PNM's production resource requirements and associated costs.

Q. How were the 10 LOLH hours selected for the proposed CP-Risk Hour Method?

A. The 10 LOLH were selected from the five months during the Test Period projected to experience LOLH. For each of those five months, PNM selected the two hours with the highest projected LOLH, resulting in a total of 10 hours. This approach captures periods of elevated reliability risk across multiple months rather than simply selecting the 10 highest LOLH hours during the Test Period, which could concentrate the selected hours within a narrower period. By selecting two hours from each of the five months, the proposed methodology reflects a broader diversity of load and system conditions throughout the Test Period while maintaining its focus on the hours most relevant to PNM's resource planning and reliability needs.

Q. Why is it important that the LOLH hours reflect the usage of multiple months?

A. The distribution of the LOLH hours across five different months demonstrates that the system's reliability risk is not necessarily confined to the traditional system peak periods. Customer loads, available resources, and system conditions can vary throughout the year. Incorporating LOLH hours from multiple months allows the proposed allocator to recognize different load patterns and periods of elevated reliability risk, resulting in a more representative measure of the conditions that contribute to PNM's need for generation capacity.

Q. Why is the proposed CP-Risk Hours Method allocator more appropriate than continuing to rely solely on the existing 3S1W CP methodology?

A. PNM's proposed methodology better reflects the relationship between customer demand, resource adequacy, and the costs incurred to maintain a reliable generation system. In an electric system with a significant amount of intermittent resources like PNM's system, production capacity is needed not simply to serve demand during a small number of traditional system peak hours, but to ensure that sufficient resources are available during periods when the system is most at risk of being unable to meet customer demand. PNM witness Larkin describes the application of this proposed allocator for production-related costs in the COST™ Model.

Q. How does PNM's proposed allocation methodology improve upon the existing 3S1W CP methodology?

A. The proposed methodology expands upon the existing 3S1W CP methodology by considering not only traditional CP conditions, but also periods of greatest projected reliability risk, as measured by LOLH. However, for continuity and stability, the proposed methodology also retains the previously approved CP hours used in the current 3S1W CP methodology. In total, the proposed allocation methodology not only incorporates LOLH hours into the current CP methodology to ensure the allocator better reflects the system conditions that contribute to PNM's need for production capacity, but also retains some of the current 3S1W CP methodology to provide continuity in allocating production-related costs.

Q. Was the allocation methodology proposed in this case specifically presented during the PRAC process?

A. No, not in its current form. However, throughout the PRAC discussions, including the work of a subcommittee established to evaluate alternative production cost allocation methodologies, PNM communicated its intent to develop a new approach that incorporated hours associated with system reliability risk rather than relying solely on traditional CP hours. Those discussions focused on evaluating alternative allocation methodologies designed to better reflect the planning and reliability conditions affecting PNM's system; however, the PRAC stakeholders did not reach agreement on a specific methodology.

Q. Why did the Company not propose the categorization and allocation of production assets based on the concept of "dispatchability," as previously discussed with stakeholders during the PRAC process?

A. I acknowledge that the Company considered the idea of separating production assets into at least two categories based on dispatchability during the PRAC discussions. However, from a resource-planning perspective, the Company's resources are planned and dispatched collectively to meet system needs, which did not provide a sufficiently strong basis for applying different allocation methodologies to different assets solely based on dispatchability. Additionally, the level of asset-specific accounting data currently available would limit the Company's ability to implement such an allocation methodology. Accordingly, the

Company determined that it would not be appropriate to pursue adopting that approach in this rate case proceeding.

B. Proposed Allocation of Transmission-Related Costs

Q. What change is PNM proposing for the allocation of transmission costs?

A. PNM plans to propose using a 12 Coincident Peak allocation methodology ("12CP Method") for retail transmission costs instead of the current 3S1W CP methodology. Under the 12CP Method, transmission costs are allocated based on customer class demand during each month's system peak, rather than four system peaks during the year. This approach reflects customer contributions to transmission system usage throughout the entire year.

Q. Why is PNM proposing to move away from the current 3S1W CP methodology?

A. The current 3S1W CP methodology was adopted as a result of the final order in Case No. 15-00261-UT,[3] when production and transmission costs were allocated using the same methodology. Through the PRAC process, PNM has concluded that transmission facilities and production resources are planned and utilized differently and therefore may warrant different allocation methodologies. For example, PNM's transmission planning evaluates a range of system conditions, including annual peak, net-peak, off-peak, high-import, and high-export conditions. Therefore,

[3] Case No. 15-00261-UT, Corrected Recommended Decision, at 199 (Aug. 15, 2016).

PNM's transmission costs should be allocated using a method that better reflects year-round use of the transmission system.

Q. Why is the 12CP Method more appropriate for transmission cost allocation today?

A. PNM's transmission system has evolved significantly over the last few years. Historically, transmission facilities primarily moved power from large, centralized generating stations to customers. See, for example, PNM Exhibit JCA-2, showing the loads of PNM's transmission Path 48 in 2015, and how those transmission loads aligned well with certain summer and winter peaks previously used for the allocation of transmission costs.[4] Under that framework, allocating transmission costs based on a small number of CPs was believed to be a reasonable proxy for how the system was used, particularly when aligned with the drivers used to allocate production costs. However, the grid is no longer characterized by a single, predictable flow of energy from production to load given that renewable generation can cause the times of highest production risk and highest transmission use to be different. For example, high renewable output may reduce production risk while increasing transmission flows as excess energy is moved across the system. PNM's growing portfolio of solar, wind, battery storage, and other distributed resources has created a more dynamic transmission system with changing power flow patterns

[4] Path 48 in the Western Electric Coordinating Council ("WECC") Path Rating Catalog includes the major transmission lines serving load in northern New Mexico. The path is also referred to as the Northern New Mexico Import ("NNMI") path. This path serves load within the PNM Balancing Area.

throughout the day and throughout the year. PNM's PRAC discussions highlighted that transmission flows increasingly occur during certain non-peak periods that do not align with retail system loads driving production.

Q. Why does the 12CP Method better reflect transmission cost causation?

A. Changes to the production fleet, including the growth of solar and wind resources and changes in power flows across the system, have resulted in transmission facilities being used heavily during many periods throughout the year. The 12CP Method captures year-round transmission demands and provides a more stable and representative measure of customer utilization of the transmission system. PNM Exhibit JCA-3 illustrates this point by showing transmission loadings on two of PNM's transmission paths in more recent years, Path 48 mentioned above, and the Eastern New Mexico Transmission system.[5] The exhibit demonstrates that significant power flows now occur at different hours and in different months throughout the year and can shift from year to year, rather than being concentrated during periods of high retail load in the summer and in certain periods of the winter, as seen in the example for 2015 for Path 48.

Q. Why is PNM not proposing to use the same risk hours used to allocate production costs to allocate transmission costs?

[5] This transmission network facilitates the transfer of power from wind generation resources in eastern New Mexico to PNM load centers.

A. Although the 12CP monthly peaks may coincide with or correlate with the four coincident peak hours still used in PNM's proposed production allocator, the additional ten CP-Risk Hours are selected to reflect production capacity risk and do not necessarily correspond to periods of high transmission system usage. LOLH hours identify periods of production reliability risk, not periods that necessarily drive transmission system usage or investment. As a result, demand during LOLH hours may not necessarily be correlated with transmission flows. Therefore, transmission costs should be allocated using an allocator that reflects customers' overall use of the transmission system and recognizes that transmission facilities must remain available throughout the year to meet periods of high demand.

Q. How does the proposed 12CP Method align with industry practice?

A. The 12CP Method is consistent with the approach PNM currently uses to allocate transmission costs between its retail and FERC-jurisdictional wholesale transmission customers. PNM witness Larkin also discusses the general use of the 12CP Method in other jurisdictions. By using the same fundamental transmission allocation methodology for both retail and wholesale jurisdictions, PNM can improve consistency in how transmission costs are assigned.

Q. What is the primary benefit of the proposed transmission allocation change?

A. The primary benefit is improved alignment between cost responsibility and the planning and actual use of the transmission system. In summary, production and

transmission systems are planned to address different needs and cost drivers. Accordingly, using different allocation methodologies for transmission and production better reflects the distinct cost drivers of each function.

C. Other Changes to Cost Allocations

Q. What compliance item from the 2024 Rate Case regarding cost allocation are you addressing in this rate case filing?

A. In accordance with the approved Stipulation in PNM's 2024 Rate Case, more specifically under paragraph 16 of the Stipulation, PNM agreed to the following:

> *Within its next rate case class cost of service study filing, PNM shall develop a cost of service for company-owned streetlights in Rate Schedule 20 separate from the cost of service for customer-owned streetlights within that rate schedule. The City agrees to work with PNM to help develop this separation between costs of service for Rate Schedule 20. PNM reserves the right to choose its preferred methods for separating the two categories of streetlights but regardless of the outcome of the discussions with the City, PNM shall provide the information developed with the City in PNM's next rate case.*

Therefore, in the COST™ Model for this case, PNM has been able to separately identify and allocate costs associated with PNM-owned and customer-owned streetlights, offered under Streetlighting Schedule 20. PNM witness Larkin explains in detail the changes incorporated into the COST™ Model to appropriately allocate certain assets and expenses between these two streetlighting categories. For purposes of cost allocation and rate design, PNM has effectively treated the two categories as separate rate schedules, while retaining them within the single Streetlighting Schedule 20 tariff through separate rate options.

Q. Has PNM discussed its proposed approach with the City of Albuquerque ("COA")?

A. Yes. Prior to filing this rate case, PNM met with the COA to present and discuss its proposed approach for allocating costs under Streetlighting Schedule 20.

Q. Has PNM used a similar approach to separately allocate costs among rate schedules within a single customer class?

A. Yes. PNM has utilized a similar approach to determine the cost responsibility associated with Residential Schedule 1B and Small Power Schedule 2B for purposes of TOD Pilot rates. PNM's goal in this case is to start identifying changes in the costs allocated to these schedules and assess how changes in customer usage patterns resulting from the TOD Pilot pricing are affecting those costs. PNM intends to use this information to evaluate the extent to which the current time-variant pricing options and the resulting changes in customer usage patterns affect the cost of serving these customers.

D. Banding

Q. What is the allocated cost-based non-fuel revenue requirement increase or decrease for each customer class?

A. The customer class cost-based non-fuel revenue requirement increases and decreases, as indicated by the COST™ and is summarized in PNM Table JCA-1 below.[6]

[6] Please note that in the Acronyms/Abbreviations at the beginning of my testimony, I provide a simple summary of each rate schedule and the relevant abbreviation for the rate schedule.

PNM Table JCA-1				
	Cost-Based Non-Fuel Revenue Increase			
Customer Class	Test Period Revenue at Current Rates	Cost-Based Increase/(Decrease)	Allocated Revenue Requirement	% Change
(A)	(B)	(C)	(D)	(E)
1 – Residential	$ 462,543,285	$ 171,358,418	$ 633,901,703	37.05%
2 - Small Power	$ 111,916,105	$ 22,168,450	$ 134,084,555	19.81%
3B - General Power	$ 123,151,613	$ 31,627,297	$ 154,778,910	25.68%
3C - General Power Low LF	$ 37,223,540	$ 3,608,949	$ 40,832,489	9.70%
3D - General Power/Municipal	$ 8,607,191	$ 2,370,248	$ 10,977,439	27.54%
3E - General Power Low LF/Municipal	$ 2,303,000	$ 341,858	$ 2,644,858	14.84%
3F - Charging Station	$ 941,870	$ 404,822	$ 1,346,692	42.98%
4B - Large Power	$ 67,116,066	$ 12,773,881	$ 79,889,946	19.03%
5B - Lg. Svc. (8 MW)	$ -	$ -	$ -	N/A
10A/B – Irrigation	$ 2,258,961	$ 683,460	$ 2,942,421	30.26%
11B - Wtr/Swg Pumping	$ 8,035,388	$ 3,454,527	$ 11,489,916	42.99%
15B - Universities 115 kV	$ 4,258,972	$ (882,907)	$ 3,376,065	-20.73%
30B - Manuf. (30 MW)	$ 32,052,215	$ 6,339,049	$ 38,391,264	19.78%
33B - Lg. Svc. (Station Power)	$ 1,337,400	$ (819,422)	$ 517,978	-61.27%
35B - Lg. Svc. (3 MW)	$ 14,292,144	$ 1,993,522	$ 16,285,667	13.95%
36B - SSR - Renew. Energy Res.	$ 58,169,054	$ 27,345,397	$ 85,514,451	47.01%
6 - Private Area Lighting	$ 2,463,478	$ (831,760)	$ 1,631,718	-33.76%
20 – Streetlighting	$ 5,439,353	$ 4,392,719	$ 9,832,072	80.76%
Total	**$ 942,109,637**	**$ 286,328,508**	**$ 1,228,438,144**	**30.39%**

The proposed total system non-fuel revenue requirement increase is 30.39%. Columns C and E show the non-fuel cost-based increase or decrease amount and percentage for each customer class, respectively.

As seen in PNM Table JCA-1, the residential customer class continues to see a need for increased cost recovery that is higher than the system increase. This reflects

ongoing investments, particularly at the distribution level, as supported by various PNM witnesses that benefit residential and small business customers.

Q. Is past banding of revenue requirement increases reflected in the relative differences in percentage impacts shown in PNM Table JCA-1?

A. Yes. Over the last several rate cases, the residential non-fuel revenue requirement increase has been kept below the allocated cost-based increase in accordance with the principles of gradualism and avoidance of rate shock. To make up the difference, other customer classes have been subsidizing residential customers. These subsidizing customer classes, based on the allocated cost-based revenue requirement, would otherwise have seen a decrease in prior rate cases had rates been set on a cost basis. In this case, only Universities Schedule 15B, Station Power Schedule 33B and Private Lighting Schedule 6 do not require an increase in non-fuel revenue, as indicated by the Class Cost of Service Study.

Q. Is PNM proposing to band the non-fuel cost-based increase or decrease in this rate case?

A. Yes. PNM continues to support movement toward cost-based rates, while also recognizing the principle of gradualism that the Commission has applied in prior cases. Moving immediately to fully cost-based rates could result in rate shock for some customer classes, while other classes could experience significant decreases.

Accordingly, PNM proposes to apply banding to both the non-fuel increases and decreases indicated by the COST™ Model.

Q. What is the banding proposal in this rate filing?

A. Given the relative magnitude of the proposed increase to non-fuel revenues, PNM proposes an upper band of 110%, which means no customer class (in aggregate) will see an increase higher than 110% of the system increase of 30.39%. This translates to a class increase of 33.43% resulting from multiplying 30.39% by 110%. PNM also proposes a lower band of 90% of the system increase, which translates into a non-fuel increase no lower than 27.24% for some customer classes. Please see PNM Table JCA-2 below for the proposed banded changes to customer class cost responsibility.

PNM Table JCA-2				
	Banded Non-Fuel Revenue Increase			
Customer Class	Test Period Revenue at Current Rates	Banded Increase	Allocated Revenue Requirement	% Change
(A)	(B)	(C)	(D)	(E)
1 – Residential	$ 462,543,285	$ 143,243,687	$ 605,786,972	30.97%
2 - Small Power	$ 111,916,105	$ 30,485,091	$ 142,401,196	27.24%
3B - General Power	$ 123,151,613	$ 33,545,558	$ 156,697,171	27.24%
3C - General Power Low LF	$ 37,223,540	$ 10,139,408	$ 47,362,948	27.24%
3D - General Power/Municipal	$ 8,607,191	$ 2,370,248	$ 10,977,439	27.54%
3E - General Power Low LF/Municipal	$ 2,303,000	$ 627,320	$ 2,930,320	27.24%
3F - Charging Station	$ 941,870	$ 314,881	$ 1,256,751	33.43%
4B - Large Power	$ 67,116,066	$ 18,281,903	$ 85,397,969	27.24%
5B - Lg. Svc. (8 MW)	$ -	$ -	$ -	N/A
10A/B – Irrigation	$ 2,258,961	$ 683,460	$ 2,942,421	30.26%
11B - Wtr/Swg Pumping	$ 8,035,388	$ 2,686,351	$ 10,721,739	33.43%
15B - Universities 115 kV	$ 4,258,972	$ 1,160,111	$ 5,419,084	27.24%
30B - Manuf. (30 MW)	$ 32,052,215	$ 8,730,778	$ 40,782,994	27.24%
33B - Lg. Svc. (Station Power)	$ 1,337,400	$ 364,298	$ 1,701,698	27.24%
35B - Lg. Svc. (3 MW)	$ 14,292,144	$ 3,893,071	$ 18,185,215	27.24%
36B - SSR - Renew. Energy Res.	$ 58,169,054	$ 27,345,397	$ 85,514,451	47.01%
6 - Private Area Lighting	$ 2,463,478	$ 671,033	$ 3,134,511	27.24%
20 – Streetlighting	$ 5,439,353	$ 1,785,912	$ 7,225,266	32.83%
Total	**$ 942,109,637**	**$ 286,328,508**	**$ 1,228,438,144**	**30.39%**

Q. Why does PNM propose an upper band of 1.1 times the system average or 110%?

A PNM's objective remains to move customer classes toward cost-based rates. However, the appropriate pace of that movement in every rate case depends in part on the magnitude of the overall rate increase. Because the proposed non-fuel increase in this case is higher than in the last rate case, applying a more aggressive upper band would compound the increase experienced by customer classes that are

already below cost of service. PNM therefore proposes a 110% upper band to balance movement toward cost-based rates with gradualism and the potential for rate shock.[7]

Q. Why does PNM propose a lower band of 0.90 times the system average?

A. The 0.90 times the system average lower band results from PNM's decision to limit the upper band to 1.1 times the system average.[8] Furthermore, using these bands provides a reasonable and balanced approach because it limits how far individual class increases may vary from the system average in either direction. Together, these bands reflect PNM's continued focus on cost-based rates, while balancing that objective against the need to moderate customer impacts given the overall magnitude of the proposed rate increase in this case.

Q. Is the proposed banding in this case addressing the subsidization issue observed for the residential customer class?

A. Yes. The proposed banding in this case results in a net subsidy of approximately $27 million for the residential customer class, which includes three rate options: Non-Low Income, Low Income, and customers participating in the TOD Pilot rate. The proposed $27 million subsidy represents a reduction from the overall subsidy

[7] Special Service Rate Schedule 36B is excluded from the classes subject to the upper band because PNM proposes to set its rates at cost-based levels, consistent with the No Net Adverse Impact standard discussed later in my testimony.

[8] The precise calculated lower band is 0.8963x system average or 89.63%. PNM rounded this value to 0.9 or 90% solely for ease of reference and comparison. This value of 0.9x system average is used throughout testimonies and supporting analyses.

provided to the residential class in the last rate case, which was approximately $41 million. Additionally, the revenue proposed to be allocated to Non-Low Income customers represents approximately 99% of their cost-based revenue requirement, bringing the rates paid by approximately 78% of PNM's residential customers substantially closer to cost-based levels. In summary, PNM's banding proposal in this case results in the majority of the subsidy remaining within the residential customer class targeted toward supporting rate affordability for Low Income customers.

Q. What rate schedules are set at the upper band of PNM's proposed banding?

A. In PNM's banding proposal, the following customer class/rate schedules will be set at the upper band, or the 1.1 times the system average: General Power Schedule 3F; Water and Sewage Schedule 11B, including the TOD option; and Streetlighting Schedule 20, for the PNM-Owned option only.

Q. What rate schedules are set at the lower band of PNM's proposed banding?

A. In PNM's banding proposal, the following customer class/rate schedules will be set at the lower band, or the 0.90 times the system average: Residential Schedule 1B; Small Power Schedule 2A; Small Power Schedule 2B; General Power Schedule 3B; General Power Schedule 3C; General Power Schedule 3E; Large Power Schedule 4B; Universities Schedule 15B; Station Power Schedule 33B;

Manufacturing Schedule 30B; Large Power Schedule 35B; and Private Lighting Schedule 6.

Q. Is PNM proposing to set any rate schedule at a cost-based level revenue requirement?

A. Yes. Although the tighter banding proposed in this case limits PNM's ability to move all customer classes and rate schedules toward cost, PNM is proposing to move certain rate schedules fully to cost-of-service levels. These include General Power Schedule 3D; Irrigation Schedules 10A and 10B; Special Service Rate Schedule 36B; and the Customer-Owned option under Streetlighting Schedule 20.

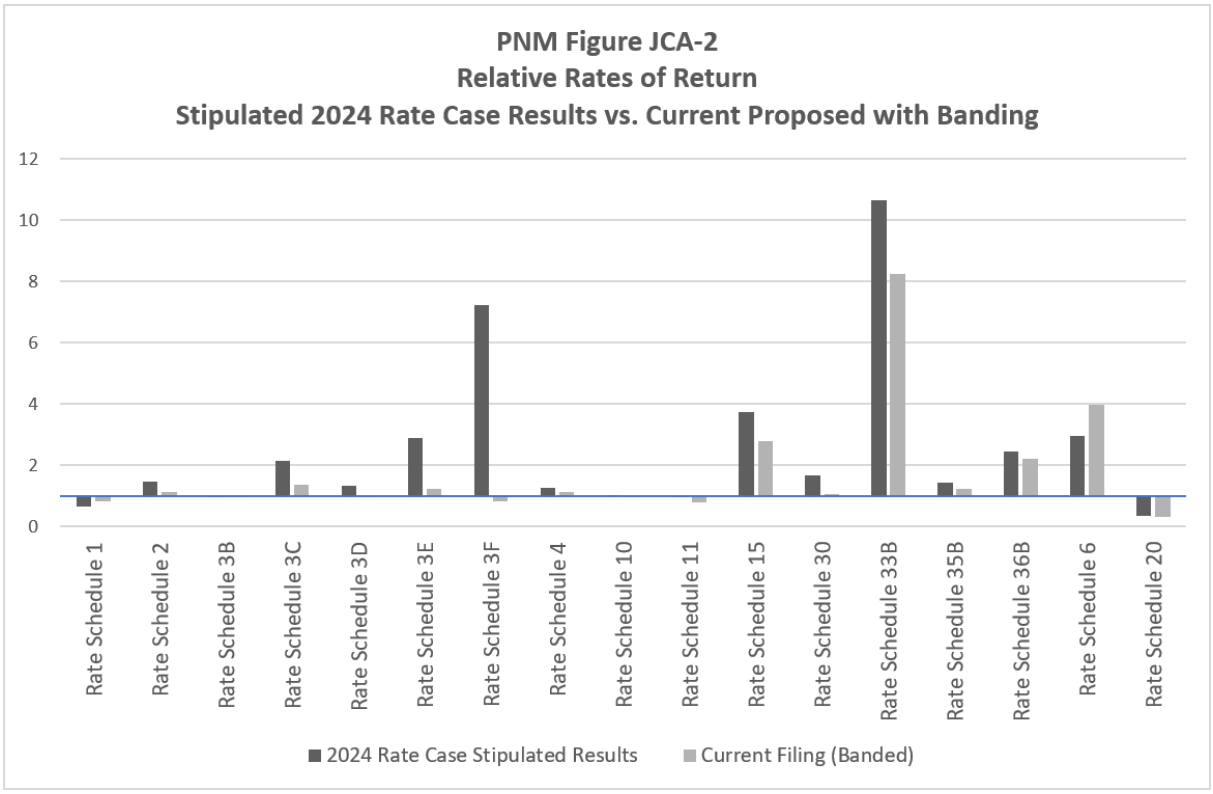
Also, as mentioned earlier, PNM is proposing to bring Non-Low Income customers under Residential Schedule 1A to approximately 99% of their cost-of-service level. Together, these proposals reflect meaningful progress toward more cost-based rates despite the constraints imposed by the proposed banding. Collectively, the schedules set at cost-based rates, and including the Non-Low Income portion of the Residential Schedule 1A, represent approximately 48% of PNM's requested non-fuel revenue in this case with rates set at cost-of-service levels.

Q. Why should Special Service Rate Schedule 36B be set at cost-based levels even though its proposed non-fuel increase exceeds the upper band?

A. The terms of the current Special Service Contract associated with this schedule require PNM to demonstrate No Net Adverse Impact associated with the service provided under Special Service Rate Schedule 36B. Accordingly, PNM must consider this requirement in establishing the proposed cost allocation and resulting rates. In Section VI below, I discuss in greater detail how PNM demonstrates compliance with this criterion.

Q. Does this banding proposal and recommended changes to the various rate schedules help to move the rates closer to cost-based?

A. Yes. The Relative Rate of Return shows the rate of return of customer class relative to the system rate of return. A value of "1" means the class is at equilibrium with the system and reflects cost-based non-fuel rates. A value above "1" indicates the class is paying above cost basis and is providing a subsidy to other classes who are not paying their full cost of service. A value below "1" indicates the class is paying less than cost basis and is receiving a subsidy from other classes who are paying more than their full cost of service. As shown in PNM Figure JCA-2 below, the majority of the rate schedules (12 of 17) show improvements, which means these rate schedules, under PNM's banding proposal, are moving closer to unity.



V. CHANGES TO RESIDENTIAL RATE DESIGN

A. Residential TOD Pilot

Q. Is PNM continuing with its plans to move toward default TOD rates?

A. Yes. PNM remains committed to the Roadmap to Default TOD (or "Roadmap") outlined in the Annual Grid Modernization Review proceeding (Docket No. 26-0000069). As PNM witness Pitts described in that case, the transition to default TOD rates is a multi-step process that depends on successful deployment of advanced metering infrastructure ("AMI"), continued customer education, and

incremental rate design modifications.[9] PNM continues to view default TOD rates as an important long-term objective that may be achieved as early as the Company's next rate case filing.

Q. What is the current status of PNM's Roadmap to Default TOD rates?

A. The Roadmap remains in progress. PNM has already implemented and continues to evaluate its TOD Pilot rates, while AMI deployment and related grid modernization investments advance. PNM is using the experience gained from the TOD Pilot, customer feedback, and load impact analysis to inform future rate design decisions and prepare for eventual default TOD implementation for residential and small power customers.

Q. How do the rate design proposals in this case relate to the Roadmap to Default TOD?

A. The proposals in this case support the objectives of the Roadmap by aligning rates more closely with cost causation and customer usage patterns. This includes specific changes to the TOD pricing structure as well as the expansion of the current TOD Pilot customer pool. The Roadmap recognizes that rates should gradually evolve to better reflect how customers use the electric system throughout the day.

[9] As Dr. Pitts explained, "PNM does not believe proposing drastic changes to residential rates in a single rate case is in the best interest of its customers." Instead, the Company is implementing Default TOD rates "more gradually over two rate cases" in a "process of incremental change" that "PNM refers to as the Roadmap to Default Time-of-Day." *See* Docket No. 26-0000069, Direct Testimony of Heidi M. Pitts, Ph.D. (Apr. 10, 2026) at 41:4-7.

By improving the underlying rate design and cost allocation framework, PNM is establishing an important foundation for future default TOD rates.

Q. Is PNM proposing default TOD rates in this proceeding?

A. No. PNM is not seeking approval of default TOD rates in this proceeding. First, AMI deployment is not complete, and AMI is required to deploy default TOD rates. However, as explained below, PNM proposes expanding the TOD Pilot in a manner that will generate additional experience and customer insights. The results will help inform future decisions regarding default TOD implementation, which PNM anticipates would be considered in a subsequent rate proceeding after deployment of AMI and additional experience is gained through the expanded TOD Pilot.

Q. Is PNM proposing any enhancements to its existing TOD Pilot program?

A. Yes. PNM proposes two main changes to its current Residential TOD Pilot: 1) to introduce a super off-peak period in the Residential TOD rate option and 2) to expand its current TOD Pilot by introducing an opt-out enrollment component.

Q. Why does PNM want to add a super off-peak period to the Residential TOD Pilot?

A. Adding a super off-peak period will provide customers with greater opportunities to reduce their bills by shifting usage to times when electricity costs are lower. This change also supports PNM's longer-term Roadmap toward a broader

implementation of TOD rates. Finally, this modification would align the Residential TOD Pilot more closely with the structure already used in PNM's commercial TOD Pilot rates.

Q. How could the super off-peak period benefit residential customers?

A. The super off-peak period creates an additional opportunity for customers to save money by using electricity during the lowest-priced hours. This is particularly important for customers who may have limited ability to reduce overall energy consumption but can shift certain activities, such as appliance use, electric vehicle charging, or other discretionary usage, to lower-cost periods. By creating a wider spread between the lowest-priced and highest-priced hours, the rate provides a stronger and more transparent price signal.

Q. Is the proposal intended primarily to increase customer savings?

A. Not fully. The proposal is intended to improve both customer bill savings opportunities and rate design effectiveness. While certain customers may realize bill savings by shifting usage to super off-peak periods, the fundamental purpose is to send more accurate price signals that encourage load during lower-cost hours and away from periods that are more costly or more challenging to serve. This helps promote more efficient utilization of the electric system.

Q. Has PNM analyzed the impact of the TOD Pilot on cost allocations?

A. Yes. In this case, PNM was able to separately evaluate the TOD Pilot participants and develop rates specifically for those customers while reflecting the changes in their hourly usage patterns. The cost-of-service analysis shows that TOD participants are allocated a lower share of costs, indicating a projected reduction in the cost to serve those customers. In fact, the analysis indicates a reduction for the TOD Pilot customers in the allocated non-fuel costs of approximately 18% and 25%, respectively, when compared to the rates currently paid under the Residential Schedule 1A and Small Power Schedule 2A. These results demonstrate that the TOD Pilot's price signals are encouraging customers to shift usage in a manner that improves utilization of the electric system, lowering the cost to serve participants, and in many instances, producing corresponding bill savings.

Q. Are these results conclusive?

A. Not necessarily. Although the current residential sample size is limited and does not support definitive conclusions, the results provide promising evidence that the TOD Pilot is producing the intended price-response effects. Specifically, participants appear to be responding to the price signals by modifying their behaviors in a way that lowers their cost to serve, suggesting a more efficient utilization of the electric system and supporting the potential for long-term customer bill savings.

Q. How does PNM intend to expand the participation in the TOD Pilot for residential customers?

A. Under PNM's proposal, approximately 4,000 residential customers whose AMI meters were installed[10] would be randomly selected for the TOD Pilot. These customers would be enrolled in the TOD Pilot by default while retaining the ability to opt out and return to standard service if they choose. These customers will also maintain the "bill guarantee" protection for 12 months upon enrollment, similar to those participating under the opt-in option.[11]

Q. Why is PNM interested in testing an opt-out enrollment approach?

A. An opt-out option for the TOD Pilot will provide valuable information regarding customer behavior under conditions that are more similar to a future default TOD rate design. The current TOD Pilot relies on customers voluntarily choosing to participate, which tends to attract customers who may be already interested in alternative rate options. An opt-out option would allow PNM to evaluate how a broader and more representative group of customers responds to TOD pricing signals.

[10] PNM's objective is to enroll the maximum practicable number of the approximately 4,000 selected customers in the experimental group, although some customers may be assigned to the control group as needed to maintain an appropriate comparison and to ensure the statistical validity of the sample.

[11] In the Grid Modernization Review filing, PNM considered the possibility of defaulting certain customer groups into the TOD Pilot (Docket No. 26-0000069, Pitts Direct, at p 46). However, defaulting a random and statistically representative sample of customers into the TOD Pilot would be a more reasonable approach, as it would provide more reliable data for evaluating customer response to time-differentiated pricing and the overall effectiveness of the TOD Pilot.

Q. How does the opt-out option differ from PNM's current opt-in TOD Pilot?

A. Under the current TOD Pilot, customers actively elect to participate in the TOD rate. Under the proposed opt-out approach, selected customers would be automatically enrolled but would be given the option to return to the standard Residential Schedule 1A rate if they prefer. This structure would allow PNM to evaluate customer understanding, participation, bill impacts, and opt-out behavior in a setting that more closely reflects a future default TOD environment.

Q. What benefits does PNM expect from expanding the TOD Pilot and including an opt-out option?

A. The opt-out option will help PNM better understand customer acceptance of TOD rates, the effectiveness of customer education and outreach efforts, and also how customers respond to time-based price signals when TOD participation is the default option. The TOD Pilot with the opt-out option will also provide information regarding opt-out behavior and customer satisfaction that can be used to inform future rate design proposals. These insights will help PNM and stakeholders assess whether additional modifications to the TOD rate offering are needed before a broader transition to default TOD rates is considered in a future rate case.

Q. How does this proposal support PNM's Roadmap to Default TOD rates?

A. Expanding the TOD Pilot to include an opt-out component represents an important intermediate step between a voluntary pilot and a future default TOD

implementation. The information gathered from the TOD Pilot will help PNM evaluate program design, customer communications, and rate structures before proposing broader implementation.

Q. Why is PNM focusing the opt-out option of the TOD Pilot on customers receiving newly installed AMI meters?

A. This proposal is meant to leverage the deployment of the technology, given that AMI meters provide the interval usage data necessary to support TOD billing and customer feedback tools. Also, PNM could evaluate how customers use and adapt to the metering technology and operational processes that would support a future default TOD program. This approach also allows PNM to study customer response across a diverse cross-section of its service territory as AMI deployment continues.

Q. Does PNM view the rate design changes proposed in this case as the final step toward default TOD rates?

A. No. The Roadmap identifies a series of incremental steps rather than a single event. The proposals in this case represent progress toward that objective, but additional work remains, including completion of AMI deployment, continued stakeholder engagement, and future rate design changes. PNM expects the transition to occur in a gradual way to promote customer understanding and mitigate unnecessary customer impacts.

Q. What is the ultimate goal of PNM's Roadmap to Default TOD?

A. The ultimate goal is to develop rate structures that provide all customers with meaningful opportunities to manage their energy costs while sending more accurate price signals that reflect how costs are incurred on the electric system. PNM's proposed approach can improve economic efficiency and better align customer behavior with system needs.

B. RESIDENTIAL RATE DESIGN

Q. What changes is PNM proposing for the existing three inclining block structure offered to residential customers?

A. PNM is proposing to begin flattening the existing three-block inclining rate structure by reducing the tier ratios for the second and third blocks and eventually moving toward a simpler rate design. This change is intended to better align the price signals provided under Residential Schedule 1A with those provided under the Residential TOD Pilot, which in fact may become the default rate option for residential customers in the future. Today, the inclining block Residential Schedule 1A primarily encourages customers to reduce total energy consumption, regardless of when energy is used, while TOD rates are intended to encourage customers to shift usage away from higher-cost peak periods. By flattening the inclining block structure, PNM can better align these incentives and provide customers with a consistent and effective rate across all residential customers, regardless of their usage.

Q. Why is PNM proposing to start flattening the existing inclining block rate structure as part of its Roadmap to Default TOD rates?

A. A flatter energy rate structure will provide for an easier transition to TOD pricing than the current inclining block design. Under an inclining block rate, customers face two separate price signals: one based on how much electricity they use and another based on when they use it if they elect a TOD rate. These signals can distort the relative economics of TOD pricing and make it more difficult for customers to choose between the two schedules and, more importantly, to understand and respond to how their actions affect their bill.

PNM's proposal simplifies the current rate structure and better aligns customer incentives with the objectives of TOD pricing and the modest flattening of the block structure proposed in this case moves the Company closer to the eventual implementation of a flat volumetric residential rate in a future rate case.

Q. Why would the transition from a flat energy rate to a TOD rate be easier than the transition from an inclining block rate to a TOD rate?

A. A flat energy rate and a TOD rate share the same fundamental pricing idea: customers pay a single energy charge for each kilowatt-hour consumed, with the primary difference being that the TOD rates change that price depending on the time of day. On the other hand, an inclining block rate introduces more complexity because energy prices vary based on the amount of energy consumed. When TOD

pricing is analyzed and compared to an inclining block design, customers must simultaneously consider both their total usage and the timing of their usage. Flattening the rate structure reduces this complexity and makes it easier for customers to understand and respond to time-based price signals.

Q. Can you please explain why an inclining block rate structure may not be compatible with TOD rates and create spurious incentives?

A. Certainly. An inclining block rate structure can create situations where high-usage customers can realize bill savings under a TOD rate even if they make little or no effort to shift consumption away from on-peak periods. In those cases, the savings may result primarily from avoiding higher-priced energy blocks rather than from reducing energy usage during more expensive periods. As a result, high-usage customers may receive a lower bill without responding to the time-based price signal provided by the TOD rate structure, creating the impression that they are contributing to a peak reduction when their usage patterns have not materially changed.

Q. Why is PNM proposing to start flattening the inclining block structure now instead of waiting until TOD becomes the default rate?

A. Flattening the inclining block structure is an important step in preparing for a future default TOD rate. The transition to a default TOD framework should occur gradually and transparently. Making incremental modifications to Residential

Schedule 1A now allows customers to adjust over time and helps ensure that future TOD implementation does not happen as a sudden change. It also allows PNM to align modifications to the Residential Schedule 1A rate with proposed enhancements to the Residential TOD Pilot, such as the addition of a super off-peak period.

Q. How will this change improve customer understanding of future residential rates?

A. A flatter (or eventually flat) energy rate structure will simplify the relationship between energy consumption and bill impacts. As customers become more familiar with TOD pricing, a less complex design would help them better understand how shifting usage away from peak hours can reduce costs. This supports customer education efforts and facilitates a smoother transition toward broader adoption of TOD rates in the future.

Q. Will this change to the inclining block structure improve bill stability and predictability for residential customers?

A. Yes. A flatter residential rate structure will provide customers with more stable and predictable bills throughout the year. Under a seasonal rate based on an inclining block structure, customers pay significantly higher energy rates during the summer months, when air conditioning use and electricity consumption are typically at their highest. A flatter rate structure can reduce seasonal variation in rates, moderate bill

changes during periods of extreme summer temperatures, and improve affordability by reducing summer bill spikes. Besides, energy consumed during the summer months is not necessarily more costly to serve generally if it occurs outside of peak or high-risk hours. An inclining block rate can distort this price signal by charging the energy at the highest tier simply because overall usage is high, even at times when energy may be abundant and inexpensive to serve, and when customers are relying on electricity to maintain comfort and safety during extreme temperatures.

Q. Does flattening the inclining block structure eliminate the incentives for energy conservation?

A. No. Customers will continue to benefit from using less energy because lower usage will still result in lower bills, and the proposed rate for the second block in both seasons still presents the customer with higher rates. Table JCA-3 below shows a comparison of the existing price tier ratios versus the proposed ratios in this case.

PNM Table JCA-3 Block Price Tier Ratios for Residential Schedule 1A				
	Summer		Non-Summer	
	Current	Proposed	Current	Proposed
Block 2 to Block 1	1.658	1.446	1.430	1.279
Block 3 to Block 2	1.342	1.325	1.326	1.310
Block 3 to Block 1	2.224	1.916	1.897	1.675

However, PNM's long-term solution focuses on the adoption of price signals that encourage all customers to use electricity during lower-cost times of the day rather than focusing exclusively on reducing total consumption. As the grid evolves, the objective of rate design is not simply to reduce electricity consumption at all times.

The objective is to encourage customers to use electricity more efficiently by consuming less when the system is constrained and shifting consumption to periods when lower-cost resources may be more abundant.

Q. Is flattening the inclining block structure part of PNM's broader Modern Rate Design Strategy?

A. Yes. The proposal is one component of PNM's broader Roadmap toward default residential TOD rates. PNM has discussed with PRAC stakeholders both modifications to the Residential TOD Pilot, including a super off-peak period, and adjustments to Residential Schedule 1A so that the two rates evolve together. Taking a coordinated approach helps ensure that residential customers receive consistent price signals and are better prepared for future rate design enabled by AMI.

Q. What other rate change is PNM proposing in this case for residential customers?

A. PNM is proposing to increase the residential customer charge to the group of residential customers considered Non-Low Income in this case, to more closely reflect the fixed costs incurred to provide service to these customers, regardless of how much electricity they consume. These costs include items such as meters, service connections, billing systems, customer service functions, and other infrastructure that must be maintained to serve customers safely and reliably.

Recovering a larger portion of these fixed costs through the customer charge improves cost causation and helps ensure customers contribute appropriately toward the costs required to make electric service available.

Q. How does a more compensatory customer charge improve rate design?

A. A more compensatory customer charge improves the alignment between how costs are incurred and how they are recovered. Customer-related costs do not vary based on the customers' energy consumption, but in PNM's case, they are recovered through volumetric energy charges. Recovering fixed customer costs through the customer charge helps improve cost fairness, reduces cross-subsidization among customers, and better aligns rates with established cost-causation principles.

Q. Will increasing the customer charge impact lower-usage customers?

A. Yes, increasing the customer charge could have a larger relative impact on lower-usage customers, who may or may not be necessarily low income customers. For that reason, PNM is proposing a Low Income Rate as part of its broader Modern Rate Design Strategy. The Low Income Rate is specifically designed to provide bill assistance to qualifying customers by establishing a $0 monthly customer charge that will help mitigate the impacts of rate changes while maintaining progress toward more cost-based rates. In addition, assuming PNM's proposal for a $0 customer charge is approved for low income customers, as the standard customer charge increases, the value of that discount also increases, providing greater bill

relief to eligible low income customers. PNM witness Babej discusses PNM's proposal to implement a Low income Rate Program in this case and the eligibility and qualification criteria for customers applying for the special rate.

Q. Could a higher customer charge reduce affordability?

A. Maybe. However, affordability is best addressed through targeted assistance rather than through broad subsidies embedded in rate design. While a lower customer charge may provide some benefit particularly to low-usage customers, it also provides the same benefit to all customers regardless of financial need. By separately proposing a more cost-reflective customer charge with a dedicated low income rate, PNM can improve cost recovery and cost causation while directing financial assistance to qualifying customers who are most likely to benefit from it.

Q. Is this proposal an example of PNM's broader Modern Rate Design Strategy?

A. Yes. Through the PRAC process, PNM emphasized the importance of aligning rates more closely with the underlying costs of providing service while also addressing customer affordability concerns. Proposing the low income discount with a more cost-based customer charge for Non-Low Income customers allows PNM to advance both objectives by improving cost recovery and directing greater bill relief to customers who need it the most.

Q. Is PNM proposing to maintain the Time-of-Use legacy rate for residential and small power customers?

A. No. As PNM anticipated since its 2022 Rate Case,[12] the Company is proposing to eliminate the TOU legacy rate and transition all existing residential and small power customers to the TOD Pilot option. PNM will notify the affected customers of this change and provide them with the opportunity to either remain on the TOD Pilot or switch to the standard Residential Schedule 1A or Small Power Schedule 2A rate schedule at any time after new rates become effective. Those customers who decide to remain in the time-variant rate will be subject to the same bill protections that other participants enrolled in the TOD Pilot program receive. The TOD Pilot will provide a more targeted price signal than the legacy TOU rate, which may give customers greater opportunities to manage their bills by shifting usage to lower-priced periods.

Q. Is PNM Proposing any changes to the Residential Whole House Electric Vehicle ("WHEV") Rate?

A. Yes. In addition to proposing revisions to the rates offered under this rate option, PNM is proposing revisions to the qualification language in Residential Schedule 1A consistent with Staff's recommendation and PNM's agreement in the most

[12] *See* Docket No. 22-00270-UT, Direct Testimony of Heidi M. Pitts, Ph.D. (Dec. 5, 2022) at 51:2-17 (stating that "PNM plans on moving all customers toward a TOD rate in the future," and noting that "[t]he rate design of the current legacy TOU rate options will remain unchanged in this filing for those customers seeking to remain on the TOU rate schedules, but PNM is proposing to close for new customers the TOU option for Rate Schedules 1B and 2B"); *see also* Docket No. 24-00089-UT, Direct Testimony of Heidi M. Pitts, Ph.D. (June 14, 2024) at 5:5-7; *see also* Docket No. 26-0000069, Direct Testimony of Heidi M. Pitts, Ph.D. (Apr. 10, 2026) at 41:16-19.

recent Transportation Electrification Program filing in Docket No. 26-000115.[13] Those revisions would remove the requirement that a residential customer receiving an electric vehicle charger take service under the WHEV rate and eliminate the existing 10,000-customer participation cap. Although the Commission has not yet issued a final order in that proceeding, PNM is proposing to reflect those agreed-upon revisions in the Advice Notice submitted in this case, subject to the Commission's ultimate determination in that case.

C. Low Income Rate Program

Q. What new rate design is PNM proposing in this case for residential customers?

A. As mentioned above, PNM is proposing a Low Income Rate Program for qualified residential customers. The proposed Low Income Rate is intended to provide bill relief to customers with limited household incomes. The objective is to provide targeted rate relief to qualifying residential customers while establishing clear eligibility criteria for participation. PNM witness Babej sponsors the Low Income Rate Program. My testimony provides details about the Low Income Rate.

Q. How will the Residential Low Income Rate be structured?

A. The proposed Residential Low Income Rate will be offered as a sub-option under PNM's existing standard Residential Schedule 1A, similar to the Whole House Electric Vehicle rate option. Qualifying customers will receive a $0 monthly

[13] Docket No. 26-000115, Direct Testimony of Staff witness Christopher S. Sanchez, at pp. 25-26 and Rebuttal Testimony of PNM witness John E. Williamson, at p. 20.

customer charge, while retaining the same block structure applicable to other residential customers.

Q. How has PNM determined the rates to be assessed on Low Income customers?

A. PNM has estimated that approximately two-thirds of the customers who may be eligible for the Low Income Rate will apply for and receive the discount during the Test Period, i.e., 22% of PNM's residential customers in the Test Period.[14] Therefore, given the uncertainty regarding the number of eligible customers who will ultimately qualify for and take service under the new Low Income Rate, PNM is proposing a tracking mechanism to compare the revenues reflected in the rate design with the revenues actually collected following implementation.

Q. How will this tracking mechanism work?

A. Each year, after the implementation of new rates resulting from this case, PNM proposes to track the difference between the Low Income billing determinants (i.e., customer counts) assumed for purposes of setting rates in this case and actual billing determinants observed after implementation. This approach is intended to account for differences between assumed and actual participation rather than relying solely on the participation estimate used to establish rates. If actual participation is higher than projected and produces a revenue shortfall, PNM would record a regulatory

[14] The estimated low income population among PNM's residential customers is approximately 167,000 customers, representing about 33% of the projected residential customers in the Test Period. Of this potentially eligible population, PNM estimates that approximately two-thirds will participate in the Low Income Rate Program in any given year, or about 110,000.

asset. If actual participation is lower than projected and produces additional revenues, PNM would record a regulatory liability.

Q. Is PNM's proposed mechanism some form of revenue decoupling?

A. No. The proposed mechanism is much narrower. It is intended only to compare the revenues from customer charges assumed in this case for customers receiving the Low Income Rate with the actual sales and revenues associated with those customers after rates are implemented. The tracking would be limited to the customer billing determinants associated with the Low Income group and would not extend to the broader residential class.

For example, assume that PNM projects that a residential customer will qualify for the Low Income Rate for the entire Test Period, but the customer does not apply and qualify until the final month. In that case, PNM would have collected more customer charge revenue from that customer during the first 11 months than what was assumed in setting rates. PNM would therefore record a regulatory liability equal to the difference between the amount actually collected during those 11 months paid by the customer (at the higher Non-Low Income rate) and the amount that would have been collected had the customer been receiving the Low Income

Rate. That amount would ultimately be returned to residential customers in a future rate case or as otherwise directed by the Commission.[15]

Q. Would qualification for the Low Income Rate be permanent?

A. No. Eligibility would be subject to periodic reevaluation to confirm that participating customers continue to meet the applicable qualifying requirements. PNM witness Babej provides further detail regarding the criteria used to determine customer eligibility for the rate and the manner in which the program will be administered.

Q. How will the costs associated with providing the Residential Low Income Rate discount be allocated?

A. The costs associated with providing the discount are allocated among other customers, including non-low income residential customers. In fact, the Non-Low income group within the residential class has been allocated approximately $12 million of the subsidy required to provide Low Income Rates in this case. PNM witness Larkin explains the methodology used to determine the allocation of these costs among customer classes.

[15] Please note that this example will track billing determinants on a customer-by-customer basis. Rather, PNM will track whether the assumed 22% participation from residential customers for the Low Income Rate Program over- or under-recovers costs.

Q. Given that the residential class as a whole is paying below cost of service, how can you claim that Non-Low Income Residential customers are contributing to the Low Income subsidy?

A. The COST™ Model provides the basis for determining the rate increase necessary to move residential customers toward cost-based rates. Under PNM's proposal, the increase for Non-Low Income Residential customers is not limited to the 1.1 times system-average cap that would otherwise apply. Instead, their increase is capped at 1.21 times the system average. The additional revenues collected from Non-Low Income customers as a result of applying the higher cap represent their contribution toward funding the Low Income subsidy, which is equivalent to about 43% of the required subsidy.

VI. LARGE LOAD RATE OFFERINGS

A. Changes to Special Service Rate Schedule 36B

Q. Please explain what PNM is demonstrating in this case with respect to the Special Service Rate Schedule 36B customer.

A. PNM demonstrates that its service to the Special Service Rate Schedule 36B customer has No Net Adverse Impact ("NNAI"), as that term is used in the SSC, on other customers with respect to rates.

Q. Please explain the requirements of the SSC that support a demonstration of No Net Adverse Impact in this proceeding.

A. The SSC expressly requires that the service provided to the customer served under Special Service Rate Schedule 36B: "…will allow PNM to recover its reasonable costs of providing electric service to Customer for the Data Center in a manner that results in No Net Adverse Impact …"[16] To that end, Exhibit D1 of the SSC shows the determination of each rate charged to the Special Service Rate Schedule 36B customer. The Special Service Rate Schedule 36B Customer Charge is designed to recover all the customer-related costs assigned to Special Service Rate Schedule 36B in PNM general rate cases. Additionally, the "Transmission Revenue Requirement," as that term is used in Exhibit D1 of the SSC, is also established in each PNM rate case, and is used to determine the "Transmission Demand Rate" that will be charged to the Special Service Rate Schedule 36B customer for the period the rates approved in the general rate case are in effect. PNM also recalculates the allocation of production costs to the Special Service Rate Schedule 36B customer in each rate case. This calculation of the charge for allocated system production revenue requirement and the Contribution to Production Component ("CTP") for the Special Service Rate Schedule 36B customer is done in accordance with Exhibit D1 of the SSC. The calculation determines if the capacity value of the system resources the Special Service Rate Schedule 36B customer pays for under Rider No. 47 - Green Energy Rider ("Rider No. 47") is greater or lesser than the Special Service Rate Schedule 36B customer's allocated system production

[16] Case No. 25-00048-UT, Direct Testimony of Julio C. Aguirre (Jun. 13, 2025), PNM Exhibit JCA-2 at Recitals, part L.

revenue requirement. PNM witness Larkin details the calculation of the CTP charge and the Transmission Demand Rate in his direct testimony.

Q. Can you further explain Exhibit D1 to the SSC as it relates to the calculation of the CTP component?

A. Yes. Exhibit D1 provides the methodology behind the "Special Service Rate Calculation." The SSC uses the methodology set forth in that exhibit to determine the Special Service Rate Schedule 36B customer's allocated production costs.[17] The result of performing the Exhibit D1 calculations is a "Contribution to Production Component" charge that is applied to the Special Service Rate Schedule 36B customer's monthly on-peak billable demand. The methodology set forth in Exhibit D1 is meant to determine the Special Service Rate Schedule 36B customer's revenue contribution to PNM's production costs for capacity supplied to the customer from PNM's traditional energy sources, taking into account the capacity provided by any "SSC Resource".[18] The capacity paid for by the Special Service Rate Schedule 36B customer is applied as an offset to the allocated production costs from PNM's energy sources.

[17] SSC, Exhibit D1 Special Service Rate Calculations, pp 42-44.
[18] Generally speaking, an "SSC Resource" means any energy generation, storage, or capacity resource contracted with by PNM on behalf of the customer served under Special Service Rate Schedule 36B, pursuant to the SSC.

Q. How does Exhibit D1, through the calculation of the CTP Component, ensure that PNM's other customers are not subsidizing the Special Service Rate Schedule 36B customer?

A. The methodology described in Exhibit D1 starts with a calculated capacity value for the system's production capacity revenue requirement. This system average capacity value is applied to the Special Service Rate Schedule 36B customer's coincident peak demands to establish its share of the production capacity revenue requirement or "Production Revenue Requirement". This is essentially the same methodology that PNM uses to assign the production capacity revenue requirement to all the other customer classes using each customer class's coincident peak demands. In this case, however, the calculation of coincident peak demands includes not only the four peak loads previously identified and used under the 3S1W allocator method, but also ten (10) additional risk hours incorporated into the Company's proposed analysis for allocating production costs.[19]

The methodology in Exhibit D1 also considers that the Special Service Rate Schedule 36B customer pays for specific renewable resources (or SSC Resources) under Rider No. 47, which PNM uses as system resources to serve all its customers. Therefore, the methodology provides a determination of the capacity value of those resources that the Special Service Rate Schedule 36B customer pays for and that

[19] Coincident peak demands in this case are based on the generation allocation method proposed by PNM, also called the CP-Risk Hour Method, which was formerly the 3S1W CP methodology. The Coincident Peak Production Methodology in the SSC was in reference to the 3S1W CP methodology.

PNM's other customers benefit from, which in D1 it is referred to as the "Production Revenue Requirement Offset". The comparison of the Special Service Rate Schedule 36B customer's allocated Production Revenue Requirement with the value of the SSC Resources that the customer pays for, i.e., the Production Revenue Requirement Offset, determines the Contribution to Production Component charge.[20]

In summary, the Special Service Rate Schedule 36B customer is always responsible for its allocated production revenue requirement for system assets and no other customers provide any subsidy to that production revenue requirement.

PNM witness Larkin provides a step-by-by derivation of the resulting Contribution to Production Component charge according to Exhibit D1.[21] It should be noted that the Special Service Rate Schedule 36B customer will not get a "refund" or a negative CTP Component charge—the best the Special Service Rate Schedule 36B customer can ever do is pay $0 for its CTP Component. This provision aids in demonstrating that other customers directly benefit if the CTP charge is calculated to be a negative number. If the CTP Component charge is positive, the Special Service Rate Schedule 36B customer will also pay its full share of the system's

[20] Section 5.1.2 of the SSC states: "…There is No Net Adverse Impact if the Test Period Revenue projected from Customer during the Company's Test Period equals or exceeds (a) the separate class Cost-Based Allocated Revenue Requirement Company is required to undertake for each Rate 36B customer in each general rate proceeding minus (b) the Production Revenue Requirement Offset Subsidy."
[21] SSC at Exhibit D1, p. 42, subpart (C).

production-related revenue requirement, in addition to the costs of the SSC Resources that the Special Service Rate Schedule 36B customer is responsible for through Rider No. 47.

Q. What is the resulting CTP Component rate estimated for the Special Service Rate Schedule 36B customer in this rate case?

A. Based on the results of the class cost-of-service study and the projected output of all SSC Resources for the Test Period in this case, PNM has determined that the CTP Component should be revised from $0 to $4.48/kW. This change results in part from the application of a different methodology for allocating production-related costs, as discussed earlier in Section IV of my testimony. The proposed CTP Component will ensure that Special Service Rate Schedule 36B is responsible for its allocated share of production costs after accounting for the production cost offset associated with the resources procured under Rider No. 47 and projected to serve the customer during the Test Period.

Q. Beyond the CTP Component calculation described previously, does Exhibit D1 also ensure there is no subsidization of the Special Service Rate Schedule 36B customer resulting from the Special Service Rate Schedule 36B customer's transmission revenue requirement allocation?

A. Yes. Exhibit D1 also provides that the transmission revenue requirement will be allocated to the Special Service Rate Schedule 36B customer based on its

coincident peak demands[22], which is the same methodology that is applied to all customer classes. Therefore, there is no potential for subsidization by other customers. Simply put, the Special Service Rate Schedule 36B customer receives a full allocation of transmission costs consistent with the allocation of these costs to other customer classes. In fact, in recent rate cases, the amount of transmission-related costs allocated to Special Service Rate Schedule 36B has exceeded the amount indicated by the Company's cost-of-service study following application of a banding methodology.

Q. Please describe how the Special Service Rate Schedule 36B customer's other charges are calculated to ensure NNAI.

A. In addition to the determination of the CTP Component charge and the transmission rate described above, PNM's application of the terms of Special Service Rate Schedule 36B ensures that no customer subsidizes the Special Service Rate Schedule 36B customer. Special Service Rate Schedule 36B includes a fully cost-based customer charge, and the Special Service Rate Schedule 36B customer pays a fuel charge pursuant to the FPPCAC based on the Special Service Rate Schedule 36B customer's hourly usage in excess of the energy produced from the renewable resources that the rate Special Service Schedule 36B customer pays for under Rider No. 47. I will also explain how Rider No. 47 and Rider No. 49 – Production Cost Allocation Rider ("Rider No. 49") ensure NNAI for other customers.

[22] In this case, using a 12CP method.

Q. How does the application of Rider No. 47 impact the Special Service Rate Schedule 36B customer's other rates?

A. First, in accordance with Rider No. 47, the Special Service Rate Schedule 36B customer's bill on a monthly basis reflects the full contractual price of any purchased power agreements ("PPAs") or ESAs entered into by PNM pursuant to the SSC to serve the Special Service Rate Schedule 36B customer. In other words, the Special Service Rate Schedule 36B customer is 100 percent responsible for the contract price of resources acquired on its behalf. This rider ensures that other customers do not have to pay for these resources, but PNM uses these resources (as system resources) to serve other customers when the Special Service Rate Schedule 36B customer's load is less than the production from these resources.

Rider No. 47 requires PNM to credit the Special Service Rate Schedule 36B customer for excess energy at a market price, which closely tracks the value of energy that PNM would otherwise be paying to cover any energy shortages. As such, these credits do not result in other customers subsidizing the Special Service Rate Schedule 36B customer.

Q. Please briefly describe Rider No. 49.

A. Rider No. 49 is a mechanism that will recover under-collected production costs from the Special Service Rate Schedule 36B customer if the CTP Component charge is set too low in a rate case. This rider requires that, within four months of

the end of the Test Period in a general rate case where a CTP Component charge has been established in accordance with Exhibit D1 of the SSC, PNM will compare actual capacity values set in accordance with the SSC to stipulated capacity values to ensure an under-collection of costs has not occurred. If an under-collection has occurred, a "Reset Rate" will be calculated in accordance with the SSC, and the under-collection will be recovered through Rider No. 49 until base rates are reset in the subsequent rate case filing.[23] Any under-recovered production costs from the Special Service Rate Schedule 36B would subsequently be returned to other customers in accordance with Rider No. 49.

Q. Please provide more information on how Rider No. 49 further ensures the Special Service Rate Schedule 36B customer pays its share of production costs such that those costs are not borne by other customers.

A. Regarding Rider No. 49, PNM recently presented to the Commission an analysis evaluating whether any under-recovery of production-related costs had occurred. As part of that analysis, PNM reconciled the information supporting the rates approved in its rate case filing for the test period spanning July 1, 2025, through June 30, 2026. Based on the approved rates, cost allocation methodologies and the actual performance of the resources procured through Rider No. 47, PNM determined that the CTP Component charge remained at zero.

[23] Rider No. 49 also contemplates an "Interim Period Charge", which will cover any potential under-collection of production costs occurring between the end of the Test Period and the effective date of the Reset Rate.

In summary, Rider No. 49 is specifically designed to ensure that the Special Service Rate Schedule 36B customer pays its fair share, in that actual capacity values are used to calculate whether the CTP Component charge is under-collecting costs from the Special Service Rate Schedule 36B customer. If an under-collection occurs, Rider No. 49 ensures that costs are collected from the Special Service Rate Schedule 36B customer and flowed back to other customers, leaving customers neutrally impacted by the SSC for the Special Service Rate Schedule 36B customer(s). Furthermore, this rider is asymmetrical, meaning that if there is an over collection by PNM, the Special Service Rate Schedule 36B customer does not get a refund. The result of Rider No. 49 is that, at worst, other customers are neutral with respect to the Special Service Rate Schedule 36B customer.

Q. In this proceeding, does Special Service Rate Schedule 36B continue to provide a subsidy to other customer classes based on the Company's banding proposal?

A. No. As shown in PNM Table JCA-1, PNM is proposing that Special Service Rate Schedule 36B be subject to cost-based rates, taking into consideration that this class is subject to the highest non-fuel revenue increase proposed in this case.

Q. What is your conclusion as to whether the NNAI standard is being met?

A. It is my conclusion that the NNAI standard for Special Service Rate Schedule 36B is being met. Other customers' rates are not impacted as a result of PNM's service to the Special Service Rate Schedule 36B customer. As discussed in the Direct Testimony of PNM witness Larkin, the calculation of the Contribution to Production Component demonstrates that the SSC Resources that the Special Service Rate Schedule 36B customer pays for offsets a share of its allocated non-fuel production revenue requirement, and the rest of the costs are being collected through the CTP Component rate of $4.48/kW/month. In addition, the Special Service Rate Schedule 36B customer pays for its fully allocated transmission cost, and the customer charge for the Special Service Rate Schedule 36B customer recovers 100% of the customer-related cost. The result is that the Special Service Rate Schedule 36B customer is not being subsidized by any other customer on PNM's system. In conclusion, the NNAI standard is projected to be met in the Test Period.

B. New Data Center Large Power Schedule 37B

Q. Is PNM proposing a new rate schedule for Data Center customers?

A. Yes. PNM is proposing a new Rate Schedule 37B, Data Center Customer Service, which is specific to only the Data Center industry segment. I co-sponsor this new rate schedule with PNM witness Kyle T. Sanders.[24]

[24] Data Center Large Power Schedule 37B is attached to witness Sanders' testimony as PNM Exhibit KTS-4.

Q. Is this type of service tariff new to PNM?

A. No, PNM has been offering service to other Data Center customers pursuant to Special Service Rate Schedule 36B. However, Special Service Rate Schedule 36B has specific requirements related to renewable energy resource procurement that may not be suitable for all the Data Center load interested in taking service from PNM.

Q. What unique requirement is PNM proposing for this new Data Center Large Power Schedule 37B?

A. PNM is proposing an Incremental Cost Test. As stated in the proposed rate schedule, in each rate case where customers are taking service under this rate schedule, PNM is required to conduct and file the results of an Incremental Cost Test that ensures that the rates provided under this schedule are recovering, at a minimum, the incremental cost of providing service to Data Center customers. The Incremental Cost Test shall ensure that the Data Center customer pays the higher of:

(A) The projected average dollar per kilowatt-hour ("kWh") cost of New System Resources, as defined in the tariff and as determined by the Company, used or projected to be used to serve Data Center customers who take or are projected to take service pursuant to this new rate schedule. This calculation is based on an assessment of what portion of New System

Resources are being used or projected to be used to serve Data Center customers.

(B) The projected average dollar per kWh cost of the Total System Resources, as defined in the tariff, used to serve Data Center customers who take or are projected to take service pursuant to this new rate schedule. This calculation is based on PNM's approved Class Cost of Service Study to allocate costs to Data Center Large Power Schedule 37B and includes any rate mitigation measures used to assign costs to this rate schedule, including banding.

Q. How did PNM calculate the proposed rates for this new Data Center Large Power Schedule 37B?

A. PNM assumed a hypothetical new 75 MW load with a 90% load factor and approximately $40 million in additional Test Period revenue requirements, representing the estimated production, transmission, and other costs necessary to serve the new (incremental) load.[25] PNM then conducted a full cost-of-service study incorporating the hypothetical load and associated costs to determine the customer's allocated share of each system cost component during the Test Period. PNM then compared those allocated costs with the corresponding incremental costs estimated to serve the new load and selected the higher amount for each cost component. This approach ensures that the potential Data Center customer would pay at least the incremental cost by function that PNM estimates it would incur to

[25] PNM's modeling assumes incremental production, transmission and customer related costs.

serve that new load. PNM then developed the tariff's specific cost-based rate elements, including customer charges, seasonal demand charges, and TOU volumetric charges[26].

Q. Is this methodology directly assigning costs to specific loads or customers?

A. No. The Incremental Cost Test essentially establishes a rate "floor" designed to ensure that customers taking service under this schedule are responsible for at least the incremental costs associated with serving their load. Accordingly, where the incremental cost exceeds the average rate amount that would otherwise be allocated under PNM's standard cost allocation methodology, the customer's rates reflect that higher amount. This recognizes that the additional costs associated with the incremental assets necessary to serve the new load are, in fact, borne by these data center customers. In effect, the Incremental Cost Test establishes a floor for setting these customers' rates, so that their rates cannot be set below that level. This rate "floor" by cost component will be evaluated every rate case, to determine the effects of any new incremental load and resources being added to serve customers under this schedule.

Q. Does this calculation account for the fact that some of the incremental costs could be subject to the FPPCAC?

[26] Energy rates were set to recover the production energy non-fuel costs.

A. Yes. The calculation of incremental costs appropriately assigns each cost component to the applicable rate recovery mechanism. In PNM's modeling, the hypothetical data center customer associated with the 75 MW of load modeled in this case would be subject to a unique and class specific FPPCAC rate that will be designed to recover at least the incremental costs that are recoverable through that rider.

Q. Is this methodology different from the one proposed originally by the Company in Case No. 26-0000114?

A. Yes. PNM has further refined the methodology proposed in that case and determined that the approach presented here provides a more appropriate basis for estimating the incremental costs associated with serving future large data center loads. PNM Exhibit JCA-4 illustrates the derivation of the Incremental Cost Test used to estimate the proposed rates for Data Center Large Power Schedule 37B.

Q. The proposed Data Center Large Power Schedule 37B mentions that the Incremental Cost Test will be conducted: "*In each Rate Case Application for which there are billing determinants under this Schedule*". However, PNM is not projecting any determinants for this rate case. Can you please reconcile those statements?

A. Yes. Although PNM is not projecting billing determinants for the Data Center Large Power Schedule 37B in this case, it is important to establish a rate now based

on the potential costs of serving this type of load. Doing so provides PNM with a tariff and rate that can be used if PNM begins serving Data Center Large Power Schedule 37B load before its next rate case filing. Once billing determinants exist, PNM would perform the corresponding Incremental Cost Test in the applicable future rate case. Additionally, PNM believes it is important to provide an example of the Incremental Cost Test, in establishing the terms of Rate Schedule 37B.

C. New Large Load Tariff for Large Power At Transmission Schedule 38B

Q. Is PNM proposing a new rate schedule for large customers taking service at transmission voltage?

A. Yes, PNM is proposing Large Power at Transmission Schedule 38B, which is also included in Advice Notice No. 667. This new Large Power rate schedule is for customers with loads equal or greater than 30 MW that take service at transmission voltage. Loads of this magnitude are typically large enough that interconnection occurs directly to the transmission system rather than through the distribution system. The proposed rate will include seasonal demand charges and TOU energy charges designed to better reflect differences in the cost of serving these customers across seasons and time periods. Please refer to PNM Exhibit JAC-6.

Q. Is this type of service tariff new to PNM?

A. No. The proposed tariff is similar in its basic service characteristics to the transmission-level Large Power service provided under Large Service Schedule 5B

and Universities Schedule 15B. The proposed tariff, however, is designed to accommodate a broader range of large-load customers, including, but not limited to, manufacturing, rather than being limited to a particular end use.

Q. Does PNM already offer other rate schedules that can serve loads greater than 30 MW?

A. Yes. However, those schedules have specific eligibility or service requirements that distinguish them from this proposed tariff. For example, Manufacturing Schedule 30B provides service at a different voltage level and includes a minimum load-factor requirement. Other schedules situated at transmission level service are designed for specific end uses, such as Universities Schedule 15B and Station Power Schedule 33B, while Special Service Rate Schedule 36B requires a commitment related to the procurement of renewable energy.

Therefore, the proposed rate schedule fills a different need by providing transmission-level service for large loads of 30 MW or greater without limiting eligibility to a particular industry, load factor or end use. In a way, PNM's proposed Large Power at Transmission Schedule 38B tariff can be viewed as a repurposing or as a successor to the type of large-load service historically provided under Large Service Schedule 5B. PNM's proposal to establish a new rate schedule with clearly defined eligibility requirements and a specific rate design for these customers provides a cleaner administrative and regulatory process and greater transparency

than attempting to modify an existing schedule that since the late 1990's was utilized to serve retail mining customers.

Q. How did PNM calculate the proposed rates for this new Large Power at Transmission Schedule 38B?

A. PNM used an approach similar to the one used for Data Center Large Power Schedule 37B. PNM assumed a hypothetical 75 MW load with a 90% load factor and approximately $40 million of additional Test Period revenue requirements representing the estimated production, transmission, and other costs that PNM estimates would be necessary to serve that new load. Then, PNM conducted a full cost of service study accounting for the load and costs to estimate the allocated share of the different system cost components projected for the Test Period. Using an approach consistent with the proposed rate design for Data Center Large Power Schedule 37B, PNM developed this tariff's cost-based rate elements, including customer charges, seasonal demand charges, and TOU volumetric charges. PNM set the customer and volumetric charges at the same levels for both schedules.

Q. Does PNM expect to serve any load for the new Large Power at Transmission Schedule 38B in the Test Period?

A. Not at this time. PNM is not forecasting any load under this schedule during the Test Period. PNM incorporated the hypothetical load, its billing determinants, and the associated costs into a separate cost-of-service analysis using the COST™

Model to develop the proposed rates for this tariff. This approach recognizes both the hypothetical new load and the additional costs assumed to serve that load. These provide a reasonable cost-based foundation for the proposed rates.

Q. If PNM does not expect any loads in the Test Period subject to the Large Power at Transmission Schedule 38B, why is the Company proposing a tariff in this case?

A. PNM is proposing Large Power at Transmission Schedule 38B to fill the gap in its rate offerings for non- Data Center loads at or above 30 MW that do not qualify for service under another schedule, particularly at transmission voltage. Although PNM does not forecast any new customers or load during the Test Period, establishing the tariff now ensures that an appropriate rate structure is available if a qualifying customer seeks service in the future.

Q. Is PNM proposing to charge cost-based rates to customers under this new rate schedule?

A. Yes. PNM proposes setting rates under this Large Power at Transmission Schedule 38B to recover the full cost-of-service revenue requirement for the class. PNM Exhibit JCA-5 shows the derivation of the proposed non-fuel rates for the Large Power at Transmission Schedule 38B. PNM witness Larkin supports how PNM estimated the cost to serve this new rate schedule using a modified COST^{TM} model.

Q. Will customers taking service under this rate be subject to the Incremental Cost Test or other financial safeguards proposed for the Data Center Large Power Schedule 37B tariff?

A. No. PNM does not propose to apply the Incremental Cost Test or the additional financial safeguards included in the Data Center Large Power Schedule 37B tariff to customers taking service under this rate. As explained in the Direct Testimony of PNM witness Sanders, those protections are intended to address the particular risks associated with very large Data Center loads. Customers eligible for this tariff are expected to include more traditional large-load industries, such as manufacturing, that generally present a different and potentially lower risk profile.

D. Proposed Changes to Other Rate Schedules (4B AND 5B)

Q. Why is PNM proposing to add a new voltage-level option under Rate 4B?

A. PNM is proposing to add one new service option under Large Power Schedule 4B for customers taking service at transmission voltage levels. This addition expands the range of service options available to large customers and recognizes that customers interconnected at different voltage levels utilize different portions of the electric system. By creating a separate voltage-level rate in Large Power Schedule 4B at transmission, PNM can more accurately align rates with the facilities and investments required to serve customers at each interconnection point. PNM witness Menhorn discusses the rate design proposed for Large Power Schedule 4B in this case.

Q. Does Large Power Schedule 4B already allow customers to take service at transmission voltage?

A. Yes. In fact, Large Power Schedule 4B currently permits service to customers interconnected at transmission voltage. However, while the tariff allows for this type of service, it does not contain a specific rate designed for customers taking service at transmission voltage. As a result, the tariff does not fully recognize the differences in facilities used and costs incurred to serve customers interconnected at transmission or distribution voltage levels.

Q. What problem is PNM trying to address with this new voltage-level rate?

A. Customers taking service at transmission voltage and distribution voltage rely on different utility assets and impose different costs on the system. Under a single rate structure, those differences may not be fully reflected in customer rates. The proposed voltage-level option improves cost causation by ensuring that rates more accurately reflect the infrastructure used to supply power at each service level and the costs incurred to provide that service. Establishing separate voltage-level rates allows PNM to recognize these differences and assign costs more appropriately based on the facilities actually used to provide service.

Q. Do the new voltage-level rates provide additional flexibility for customers?

A. Yes. The proposal increases the service options available to current and prospective large power customers by providing rate structures tailored to different

interconnection configurations. Customers will have greater flexibility to select the service level that best aligns with their operational needs while ensuring that rates more accurately reflect the specific electric infrastructure required to serve them.

Q. Is the purpose of the proposal to provide a discount to certain customers?

A. No. The primary purpose of the proposal is not to provide a discount, but rather to improve cost causation and rate design. The proposed voltage-level rate recognizes that customers interconnected at different voltage levels use different portions of the electric system and therefore should be subject to rates that more accurately reflect the costs of serving them.

Q. How does this proposal benefit existing customers?

A. By improving the relationship between rates and the costs incurred to serve different customers, the proposal promotes more accurate cost recovery and improves the price signals. This helps reduce the potential for cost misallocation among customer groups and supports a rate structure in which customers pay rates that are more closely aligned with the facilities and services they use and benefit from.

Q. Will this proposal address any existing customer eligibility issues under any current tariff structure?

A. Yes. PNM currently serves at least one customer under Large Service Schedule 5B that no longer satisfies the tariff's related eligibility requirements. Although that customer continues to take service at transmission voltage, there is currently no other alternative transmission-voltage rate available. The proposed transmission-voltage Large Power Schedule 4B option resolves this issue by providing an appropriate service option for customers that take service at transmission voltage, but that technically no longer qualify for Large Service Schedule 5B. This change helps ensure that customers are served under rates that accurately reflect both their service characteristics and the facilities used to provide service.

Q. Based on these circumstances, what is PNM proposing to do with Large Service Schedule 5B in this case?

A. PNM is proposing to eliminate Large Service Schedule 5B because the tariff no longer serves its intended purpose and is no longer needed given the other tariff changes proposed in this case. That is, no current customer would qualify for service under Large Service Schedule 5B's existing eligibility requirements. As explained above, the customer currently receiving service under Large Service Schedule 5B no longer meets the tariff's minimum demand requirements and remains on the rate because there is no alternative tariff option for transmission-voltage service. The proposed transmission-voltage option under Large Power Schedule 4B addresses that gap.

Q. What other changes is PNM proposing for Large Power Schedule 4B?

A. PNM is also proposing to establish a maximum demand threshold of 30 MW for customers taking service under Large Power Schedule 4B. This change clarifies the intended application of the tariff and creates a clear distinction between traditional large power service under Large Power Schedule 4B and PNM's existing and new large-load tariff offerings.

Q. Why is PNM proposing a 30 MW cap for Large Power Schedule 4B?

A. Customers with demands of 30 MW and above have service characteristics, infrastructure requirements, and operational impacts that are more appropriately addressed through tariffs and special service contracts that are specifically designed for large-load customers. Establishing a 30 MW cap under Large Power Schedule 4B creates a clear transition point between the Company's traditional large power service and its new large-load service offerings. The proposed 30 MW cap is also consistent with the existing eligibility limit set under Large Power Schedule 35B. Similar to Large Power Schedule 4B, Large Power Schedule 35B serves large customers, however, the latter requires customers to meet a minimum load factor and to take service directly from a PNM-owned substation.

Q. How does the proposed 30 MW cap relate to PNM's large-load tariff strategy?

A. The proposed cap helps define the boundary between large power service and the tariffs PNM has developed for large-load customers. Large Power customers with

demands below 30 MW would continue to be served under Large Power Schedules 4B or 35B, while customers with larger demand requirements would be directed to tariffs specifically designed to reflect the unique operational, planning, and infrastructure considerations associated with large-load service. This creates a more structured and logical framework for serving relatively large load customers of different sizes.

VII. CONCLUSION

Q. What conclusions should the Commission draw from your testimony?

A. PNM's proposals in this case represent another important step in the Company's transition toward a more modern, cost-reflective rate design. As PNM's electric system continues to evolve, its cost allocation and rate design methodologies must also evolve to better reflect how the system is planned, operated, and used by customers. At the same time, these changes should be implemented in a measured manner that considers customer impacts, affordability, and the principle of gradualism.

Consistent with those objectives, I recommend that the Commission approve PNM's proposed changes to production and transmission cost allocation, including the CP-Risk Hour Method for production costs and the 12CP Method for transmission costs. These methodologies recognize the different cost drivers associated with production and transmission and better reflect the changing

operational characteristics of PNM's system. I also recommend approval of PNM's proposed banding, which balances continued movement toward cost-based rates with the need to mitigate non-fuel customer impacts.

For residential customers, PNM's proposals continue the gradual transition toward a more modern rate design through enhancements to the TOD Pilot, initial flattening of the inclining-block structure, a more cost-reflective customer charge, and targeted assistance for qualifying low income customers. Collectively, these changes are intended to improve price signals and cost causation while providing additional tools to address affordability and preparing customers for a future transition to default TOD rates.

Finally, PNM's proposed large-load tariffs establish clearer and more cost-reflective frameworks for serving new large loads while protecting existing customers from inappropriate cost shifts. PNM also demonstrates that the NNAI standard applicable to Special Service Rate Schedule 36B continues to be satisfied. I therefore recommend that the Commission approve the cost allocation, banding, and rate design proposals supported in my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

GCG#536241

PNM Exhibit JCA-1
Statement of Qualifications

Is contained in the following 5 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
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 System Resources and the Abandonment of the Four Corners Power Plant.	New Mexico Public Regulation Commission	26-0000114

In the Matter of Public Service Company of New Mexico's Application for Approval of its 2027-2029 Transportation Electronification Program (Adopted)	New Mexico Public Regulation Commission	26-0000115
In the Matter of Public Service Company of New Mexico's Advice Notice No. 665 Seventh Revised Rate No. 33B Large Service for Station Power (Time-of-Use).	New Mexico Public Regulation Commission	26-0000166

PNM Exhibit JCA-2

2015 Comparison of Transmission Loading and PNM Firm Load

Is contained in the following 1 page.

Page 1 of 1

PNM Exhibit JCA-2: 2015 Comparison of Transmission Loading and PNM Firm Load

Average PNM Firm Load - 2015

Month

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	994	915	841	796	805	971	979	995	909	807	892	1001
2	968	887	821	777	781	929	940	956	874	788	865	967
3	958	877	816	772	774	905	918	932	859	780	854	953
4	957	879	829	782	779	903	918	930	859	793	856	953
5	979	902	873	833	818	927	947	962	899	836	878	974
6	1038	961	963	910	863	957	982	1012	974	922	939	1034
7	1138	1062	1020	942	913	1037	1051	1064	1006	965	1023	1125
8	1179	1088	1026	958	950	1113	1129	1137	1053	981	1049	1161
9	1169	1083	1026	972	988	1200	1213	1224	1116	1009	1052	1161
10	1164	1075	1024	978	1013	1280	1294	1312	1180	1028	1051	1155
11	1147	1062	1011	982	1034	1350	1365	1390	1236	1043	1045	1136
12	1129	1047	1000	978	1045	1409	1425	1462	1291	1047	1033	1114
13	1105	1030	994	985	1058	1467	1484	1533	1349	1064	1021	1097
14	1085	1020	989	990	1068	1508	1531	1585	1400	1082	1011	1084
15	1074	1013	989	994	1073	1539	1562	1626	1435	1097	1010	1078
16	1083	1015	996	1000	1082	1558	1565	1643	1457	1109	1025	1095
17	1115	1034	1003	1003	1082	1548	1532	1624	1443	1113	1061	1116
18	1229	1093	1024	1008	1074	1517	1479	1575	1399	1140	1172	1229
19	1268	1191	1097	1042	1075	1467	1421	1520	1396	1170	1199	1317
20	1275	1188	1132	1113	1134	1462	1422	1528	1380	1145	1180	1303
21	1263	1177	1094	1064	1102	1415	1379	1439	1289	1083	1161	1288
22	1206	1125	1011	973	1008	1280	1255	1291	1159	984	1104	1234
23	1114	1037	923	886	911	1137	1126	1149	1036	895	1017	1141
24	1041	968	871	833	846	1040	1035	1055	955	842	950	1063

Winter Peak Load

Summer Peak Load

Winter Peak

Transmission Path 48 (MW) Absolute Values - 2015

Month

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	1,312	1,096	1,076	909	940	1,155	1,215	1,210	1,102	975	1,175	1,139
2	1,287	1,065	1,071	892	921	1,137	1,201	1,191	1,073	954	1,140	1,096
3	1,276	1,051	1,068	895	919	1,113	1,186	1,165	1,062	943	1,130	1,082
4	1,277	1,059	1,092	923	933	1,122	1,195	1,157	1,075	957	1,131	1,092
5	1,277	1,078	1,133	963	983	1,149	1,231	1,192	1,127	1,007	1,155	1,117
6	1,321	1,133	1,201	1,023	1,024	1,165	1,264	1,233	1,207	1,057	1,221	1,157
7	1,389	1,216	1,212	1,028	1,059	1,244	1,313	1,284	1,227	1,057	1,287	1,227
8	1,411	1,173	1,196	1,042	1,081	1,312	1,380	1,350	1,264	1,042	1,266	1,232
9	1,396	1,144	1,187	1,027	1,114	1,377	1,436	1,409	1,294	1,030	1,252	1,221
10	1,387	1,135	1,178	994	1,142	1,419	1,461	1,469	1,329	1,014	1,242	1,203
11	1,371	1,108	1,178	985	1,157	1,428	1,489	1,501	1,345	1,012	1,215	1,169
12	1,343	1,086	1,158	974	1,151	1,427	1,523	1,530	1,377	1,003	1,191	1,139
13	1,320	1,075	1,150	976	1,164	1,470	1,569	1,582	1,419	995	1,175	1,113
14	1,300	1,061	1,144	972	1,166	1,481	1,588	1,592	1,448	994	1,155	1,081
15	1,293	1,053	1,144	968	1,164	1,485	1,587	1,610	1,454	999	1,156	1,094
16	1,298	1,060	1,135	965	1,170	1,470	1,563	1,609	1,449	1,005	1,172	1,123
17	1,334	1,089	1,131	969	1,164	1,463	1,522	1,593	1,439	1,011	1,227	1,186
18	1,435	1,164	1,164	989	1,171	1,456	1,496	1,565	1,419	1,030	1,316	1,297
19	1,494	1,254	1,204	1,037	1,184	1,452	1,470	1,551	1,420	1,028	1,333	1,313
20	1,489	1,263	1,194	1,081	1,242	1,465	1,499	1,577	1,417	1,024	1,330	1,295
21	1,481	1,254	1,168	1,043	1,183	1,436	1,465	1,521	1,370	1,023	1,319	1,291
22	1,447	1,215	1,120	989	1,126	1,380	1,415	1,435	1,287	992	1,300	1,252
23	1,371	1,144	1,056	933	1,018	1,237	1,312	1,291	1,177	977	1,258	1,197
24	1,330	1,127	1,064	928	976	1,169	1,256	1,238	1,125	975	1,214	1,159

Path 48 Max Loading

Path 48 Max Loading

Path 48 Max

PNM Exhibit JCA-3

2022-2025 Comparison of Transmission Loading and PNM Firm Load

Is contained in the following 4 pages.

PNM Exhibit JCA-3: 2022 Comparison of Transmission Loading and PNM Firm Load

Average PNM Firm Load - 2022

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	1,098	1,112	1,003	944	977	1,111	1,214	1,130	1,074	956	1,088	1,156
2	1,087	1,096	987	929	947	1,069	1,168	1,090	1,042	942	1,073	1,137
3	1,083	1,089	988	918	928	1,040	1,132	1,065	1,021	938	1,073	1,131
4	1,083	1,094	996	927	928	1,033	1,120	1,062	1,017	943	1,081	1,136
5	1,106	1,118	1,029	962	952	1,050	1,134	1,087	1,038	978	1,105	1,151
6	1,153	1,160	1,089	1,013	973	1,066	1,146	1,125	1,085	1,040	1,155	1,191
7	1,221	1,233	1,134	1,021	991	1,102	1,192	1,152	1,090	1,075	1,218	1,257
8	1,252	1,252	1,126	986	996	1,142	1,249	1,191	1,102	1,069	1,219	1,286
9	1,224	1,217	1,096	970	1,005	1,192	1,311	1,235	1,123	1,055	1,185	1,269
10	1,176	1,178	1,057	953	1,026	1,247	1,381	1,296	1,161	1,042	1,147	1,226
11	1,135	1,138	1,025	949	1,059	1,308	1,478	1,363	1,213	1,030	1,119	1,196
12	1,100	1,107	1,000	953	1,099	1,379	1,566	1,445	1,277	1,028	1,100	1,169
13	1,082	1,078	989	968	1,149	1,449	1,648	1,518	1,354	1,036	1,088	1,153
14	1,073	1,066	992	986	1,208	1,522	1,727	1,577	1,431	1,057	1,089	1,154
15	1,080	1,070	999	1,014	1,274	1,583	1,786	1,631	1,495	1,089	1,108	1,168
16	1,104	1,097	1,022	1,060	1,347	1,626	1,821	1,657	1,546	1,133	1,147	1,206
17	1,164	1,147	1,067	1,108	1,393	1,634	1,819	1,654	1,561	1,165	1,207	1,261
18	1,264	1,216	1,115	1,132	1,401	1,612	1,785	1,627	1,527	1,196	1,292	1,361
19	1,309	1,292	1,178	1,150	1,371	1,566	1,727	1,576	1,499	1,208	1,310	1,373
20	1,301	1,291	1,200	1,182	1,362	1,539	1,685	1,552	1,457	1,190	1,297	1,362
21	1,286	1,286	1,173	1,146	1,303	1,476	1,609	1,480	1,379	1,149	1,278	1,349
22	1,244	1,250	1,121	1,084	1,199	1,366	1,491	1,371	1,278	1,086	1,233	1,308
23	1,184	1,189	1,064	1,016	1,094	1,253	1,371	1,260	1,181	1,020	1,173	1,244
24	1,130	1,138	1,020	972	1,029	1,171	1,278	1,184	1,115	980	1,126	1,190

Summer Peak Load

Transmission Path 48 (MW) Absolute Values - 2022

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	501	694	561	586	266	367	634	772	479	428	447	411
2	504	693	576	594	283	413	720	786	504	447	441	399
3	512	689	584	577	300	464	759	802	495	461	463	429
4	550	712	559	560	309	541	737	806	484	493	512	454
5	575	686	554	567	357	641	783	804	498	515	484	447
6	561	640	604	612	368	674	838	870	551	573	476	453
7	558	620	630	626	344	619	856	841	566	631	499	452
8	550	605	599	609	357	636	866	833	544	643	497	475
9	563	607	584	625	378	716	914	798	540	618	530	518
10	538	625	545	646	440	725	939	824	604	598	585	593
11	525	600	594	673	481	727	1,018	881	699	604	622	651
12	557	564	621	705	498	712	1,022	940	761	593	647	668
13	565	567	622	752	477	680	1,014	937	780	572	693	650
14	589	622	619	757	457	660	1,149	899	701	578	708	633
15	580	622	578	743	438	657	1,073	870	663	581	717	598
16	573	625	560	718	440	605	915	852	617	608	718	576
17	625	651	529	635	403	563	812	815	565	614	684	498
18	631	682	552	485	357	502	714	849	545	603	599	443
19	603	699	570	360	342	493	726	818	436	578	583	424
20	598	682	568	351	333	515	657	731	356	538	600	441
21	581	661	548	420	330	456	579	661	350	499	556	399
22	499	647	553	508	344	368	546	624	351	474	543	431
23	476	639	529	526	286	328	543	661	365	438	510	444
24	478	697	528	530	292	329	548	700	421	438	479	451

Path 48 Max Loading

ENM Transmission (MW) Absolute Values -2022

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	1,354	1,270	1,037	1,405	1,025	1,063	790	542	874	842	1,120	1,367
2	1,341	1,236	1,009	1,359	980	1,005	670	503	842	828	1,095	1,349
3	1,318	1,196	1,002	1,302	937	954	588	474	841	812	1,118	1,335
4	1,278	1,210	975	1,254	877	935	541	459	828	764	1,140	1,366
5	1,268	1,202	930	1,224	847	897	504	467	808	720	1,121	1,352
6	1,286	1,180	895	1,189	834	837	454	442	790	697	1,100	1,349
7	1,265	1,175	878	1,131	788	732	355	405	698	656	1,108	1,350
8	1,225	1,166	785	1,075	775	709	290	317	524	583	1,064	1,374
9	1,159	1,085	691	1,136	800	683	264	332	510	601	1,029	1,332
10	1,043	1,038	715	1,176	907	653	237	349	472	640	1,069	1,331
11	1,026	1,049	762	1,189	960	639	188	349	459	633	1,099	1,399
12	1,022	1,054	817	1,219	1,014	667	197	366	474	654	1,112	1,415
13	1,030	1,094	862	1,296	1,063	718	290	426	515	700	1,128	1,416
14	1,064	1,103	909	1,329	1,118	818	373	513	621	760	1,131	1,420
15	1,086	1,104	953	1,364	1,179	930	482	571	691	796	1,149	1,431
16	1,056	1,107	983	1,419	1,266	1,023	662	617	759	833	1,161	1,436
17	1,025	1,144	1,023	1,450	1,288	1,084	779	665	854	849	1,143	1,413
18	1,090	1,097	1,009	1,471	1,308	1,191	864	704	922	861	1,178	1,445
19	1,191	1,116	1,030	1,403	1,270	1,222	881	724	1,039	888	1,210	1,408
20	1,236	1,159	1,100	1,441	1,264	1,201	940	780	1,118	916	1,205	1,331
21	1,238	1,210	1,120	1,502	1,280	1,212	971	814	1,097	957	1,185	1,362
22	1,293	1,237	1,140	1,538	1,218	1,205	931	769	1,024	952	1,181	1,390
23	1,325	1,231	1,104	1,479	1,081	1,179	874	694	949	867	1,181	1,361
24	1,322	1,220	1,061	1,442	1,071	1,137	860	641	950	859	1,172	1,384

Wind Max Output

Wind Max Output

PNM Exhibit JCA-3: 2023 Comparison of Transmission Loading and PNM Firm Load

Average PNM Firm Load - 2023

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	1,174	1,134	1,053	984	990	1,081	1,326	1,186	1,061	944	1,032	1,118
2	1,157	1,118	1,039	968	962	1,040	1,272	1,145	1,031	927	1,019	1,099
3	1,152	1,116	1,039	965	941	1,011	1,231	1,116	1,012	915	1,013	1,093
4	1,152	1,121	1,052	977	943	1,000	1,211	1,102	1,005	918	1,013	1,096
5	1,172	1,145	1,088	1,013	968	1,013	1,215	1,118	1,023	945	1,032	1,112
6	1,217	1,191	1,152	1,066	994	1,028	1,220	1,151	1,065	1,003	1,081	1,159
7	1,289	1,259	1,191	1,078	1,012	1,053	1,260	1,174	1,073	1,022	1,138	1,224
8	1,323	1,279	1,177	1,052	1,011	1,077	1,310	1,211	1,080	1,009	1,138	1,244
9	1,297	1,243	1,139	1,018	1,004	1,104	1,378	1,255	1,099	984	1,099	1,209
10	1,253	1,197	1,106	986	1,012	1,143	1,462	1,315	1,124	974	1,064	1,163
11	1,219	1,156	1,080	961	1,031	1,198	1,553	1,385	1,170	969	1,034	1,120
12	1,185	1,132	1,061	952	1,064	1,263	1,651	1,468	1,234	978	1,018	1,090
13	1,169	1,110	1,052	954	1,101	1,336	1,755	1,558	1,310	1,006	1,016	1,069
14	1,174	1,107	1,052	969	1,153	1,406	1,853	1,645	1,393	1,049	1,022	1,070
15	1,188	1,119	1,064	1,000	1,199	1,485	1,930	1,710	1,457	1,102	1,048	1,093
16	1,215	1,141	1,095	1,047	1,247	1,545	1,980	1,763	1,513	1,165	1,091	1,141
17	1,271	1,188	1,139	1,107	1,290	1,577	2,002	1,781	1,546	1,215	1,157	1,214
18	1,360	1,258	1,191	1,154	1,306	1,578	1,984	1,762	1,529	1,233	1,236	1,314
19	1,398	1,329	1,242	1,180	1,293	1,536	1,923	1,703	1,486	1,230	1,239	1,330
20	1,386	1,329	1,255	1,213	1,302	1,502	1,865	1,666	1,443	1,203	1,225	1,319
21	1,372	1,320	1,232	1,175	1,254	1,441	1,777	1,577	1,369	1,155	1,212	1,312
22	1,330	1,278	1,178	1,114	1,172	1,334	1,638	1,453	1,272	1,085	1,172	1,273
23	1,261	1,215	1,122	1,054	1,088	1,227	1,511	1,331	1,183	1,019	1,117	1,215
24	1,205	1,164	1,080	1,008	1,030	1,144	1,407	1,246	1,110	972	1,068	1,156

Summer Peak Load

Transmission Path 48 (MW) Absolute Values - 2023

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	664	559	569	616	525	435	328	410	378	542	657	361
2	662	558	570	606	504	417	391	405	383	572	664	347
3	674	556	568	625	504	441	454	412	419	550	652	348
4	649	559	575	608	512	476	503	412	434	557	591	347
5	656	557	568	623	524	534	508	474	458	534	537	353
6	652	509	583	640	564	595	543	566	486	520	474	365
7	627	468	580	652	518	585	571	593	470	483	439	372
8	595	449	575	624	485	570	605	574	431	430	479	384
9	581	445	594	671	470	589	653	532	427	416	443	385
10	588	485	638	681	502	557	727	514	437	449	458	414
11	617	528	712	650	527	568	708	539	507	470	497	448
12	623	601	769	648	528	586	764	566	558	492	525	428
13	642	638	744	636	515	593	736	642	602	505	535	436
14	700	674	763	658	497	578	732	663	632	496	535	448
15	729	670	729	649	470	547	672	635	611	494	520	436
16	688	621	731	630	460	530	676	543	559	474	531	425
17	586	593	731	685	462	493	683	497	523	474	560	434
18	572	552	679	711	461	486	602	428	473	429	449	391
19	569	545	555	635	408	494	436	446	435	421	448	351
20	585	519	554	540	384	506	392	428	344	444	479	342
21	631	518	633	564	390	440	370	468	335	485	541	369
22	669	498	621	575	459	389	339	458	374	486	584	378
23	680	476	616	626	490	429	315	387	374	490	607	367
24	681	496	620	606	486	420	332	395	362	503	612	363

Path 48 Max Loading

Path 48 Max Loading

ENM Transmission (MW) Absolute Values -2023

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	1,557	1,378	1,400	1,293	1,032	1,016	1,119	1,058	951	1,014	1,191	933
2	1,544	1,281	1,381	1,204	916	926	1,082	1,054	941	976	1,206	947
3	1,517	1,289	1,378	1,195	786	851	1,067	1,047	919	937	1,207	963
4	1,479	1,302	1,363	1,192	757	768	1,016	957	876	888	1,207	960
5	1,466	1,321	1,369	1,182	732	718	979	868	812	836	1,169	958
6	1,424	1,335	1,366	1,155	679	657	937	859	783	801	1,140	974
7	1,433	1,325	1,311	1,139	611	525	821	778	742	789	1,125	1,020
8	1,472	1,324	1,240	1,103	580	477	722	708	615	688	1,068	1,036
9	1,437	1,224	1,251	1,177	598	519	673	707	630	614	930	987
10	1,403	1,245	1,387	1,191	639	586	586	697	632	631	923	922
11	1,449	1,263	1,458	1,126	676	693	515	670	634	634	964	907
12	1,446	1,307	1,475	1,146	722	808	490	678	677	658	966	944
13	1,482	1,325	1,478	1,176	797	925	501	669	749	687	971	942
14	1,533	1,338	1,478	1,243	899	1,043	571	711	818	733	969	915
15	1,553	1,347	1,465	1,258	990	1,124	690	816	886	775	950	898
16	1,543	1,301	1,521	1,296	1,104	1,145	863	917	1,002	841	924	876
17	1,540	1,242	1,604	1,388	1,171	1,211	989	1,021	1,021	963	938	891
18	1,530	1,219	1,602	1,448	1,213	1,142	1,147	1,141	1,005	1,021	988	957
19	1,540	1,252	1,528	1,420	1,202	1,035	1,240	1,198	1,013	1,104	1,071	998
20	1,558	1,265	1,509	1,473	1,193	962	1,260	1,211	1,146	1,142	1,148	993
21	1,557	1,297	1,509	1,473	1,178	1,012	1,254	1,254	1,180	1,140	1,193	985
22	1,541	1,267	1,492	1,450	1,143	1,125	1,271	1,210	1,155	1,111	1,222	961
23	1,496	1,264	1,514	1,423	1,119	1,131	1,266	1,145	1,113	1,069	1,201	962
24	1,482	1,300	1,454	1,340	1,069	1,082	1,213	1,097	1,040	1,046	1,204	945

Wind Max Output

PNM Exhibit JCA-3: 2024 Comparison of Transmission Loading and PNM Firm Load

Average PNM Firm Load - 2024

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	1,153	1,115	1,056	982	1,001	1,170	1,163	1,204	1,091	1,022	1,113	1,184
2	1,136	1,100	1,044	968	975	1,127	1,121	1,166	1,056	1,002	1,096	1,166
3	1,129	1,098	1,041	960	956	1,095	1,087	1,132	1,033	990	1,090	1,157
4	1,131	1,102	1,048	970	962	1,077	1,074	1,121	1,029	995	1,091	1,160
5	1,147	1,122	1,078	1,007	985	1,087	1,086	1,140	1,052	1,024	1,111	1,179
6	1,193	1,175	1,139	1,062	1,001	1,097	1,090	1,168	1,096	1,082	1,157	1,227
7	1,266	1,246	1,175	1,068	1,008	1,130	1,119	1,187	1,099	1,098	1,219	1,296
8	1,294	1,258	1,154	1,032	998	1,161	1,155	1,225	1,100	1,081	1,217	1,312
9	1,267	1,216	1,110	994	985	1,206	1,202	1,267	1,111	1,066	1,183	1,267
10	1,221	1,166	1,062	966	994	1,264	1,265	1,331	1,141	1,058	1,133	1,209
11	1,183	1,118	1,016	947	1,009	1,335	1,343	1,407	1,181	1,062	1,096	1,154
12	1,149	1,084	997	944	1,037	1,403	1,431	1,491	1,244	1,086	1,076	1,117
13	1,133	1,060	987	947	1,078	1,485	1,525	1,587	1,324	1,129	1,076	1,095
14	1,129	1,054	987	966	1,132	1,562	1,623	1,681	1,414	1,194	1,082	1,102
15	1,142	1,071	1,007	1,002	1,185	1,643	1,714	1,766	1,503	1,264	1,115	1,128
16	1,183	1,098	1,043	1,053	1,252	1,711	1,778	1,828	1,581	1,338	1,166	1,182
17	1,243	1,154	1,101	1,110	1,302	1,742	1,810	1,842	1,624	1,381	1,236	1,260
18	1,336	1,234	1,160	1,153	1,332	1,731	1,786	1,804	1,611	1,380	1,305	1,353
19	1,366	1,299	1,222	1,185	1,329	1,683	1,719	1,739	1,555	1,352	1,315	1,373
20	1,357	1,299	1,240	1,215	1,321	1,636	1,653	1,687	1,497	1,311	1,306	1,371
21	1,344	1,291	1,216	1,178	1,274	1,557	1,566	1,599	1,409	1,251	1,291	1,370
22	1,303	1,253	1,170	1,119	1,197	1,445	1,446	1,473	1,306	1,179	1,255	1,336
23	1,240	1,195	1,115	1,057	1,112	1,328	1,327	1,355	1,209	1,103	1,202	1,283
24	1,187	1,149	1,076	1,006	1,047	1,237	1,234	1,267	1,139	1,050	1,152	1,224

Summer Peak Load

Transmission Path 48 (MW) Absolute Values - 2024

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	639	601	668	580	631	481	413	474	482	481	492	563
2	643	631	646	574	608	495	434	535	507	471	507	607
3	619	655	607	571	583	479	459	583	505	449	507	616
4	604	609	572	599	597	447	504	592	552	465	487	643
5	567	677	549	466	597	448	556	686	635	481	526	636
6	596	668	538	456	553	444	560	735	695	446	550	624
7	646	614	563	540	536	429	441	561	566	428	519	614
8	650	601	681	600	563	445	363	398	380	484	535	593
9	633	641	767	609	579	445	310	332	385	565	660	612
10	610	673	747	623	608	467	330	323	359	547	656	587
11	578	687	699	620	637	450	368	357	337	512	585	612
12	594	681	651	624	669	455	401	349	319	469	558	634
13	573	689	629	675	714	460	410	374	345	502	642	696
14	538	687	605	697	737	453	445	342	358	480	681	733
15	533	679	616	703	683	484	458	416	366	479	710	733
16	555	691	620	723	693	583	418	460	426	509	654	691
17	504	636	599	692	679	589	477	514	440	494	621	651
18	528	590	528	536	610	515	453	592	587	526	582	612
19	518	602	522	490	517	531	493	667	529	453	556	604
20	539	597	566	566	562	571	496	573	426	447	574	624
21	561	576	640	625	611	563	397	492	386	457	575	627
22	599	579	670	659	626	559	421	436	360	487	556	629
23	622	596	636	588	579	488	453	475	389	467	538	609
24	628	609	665	552	589	435	468	491	404	473	512	573

Path 48 Max Loading

Path 48 Max Loading

ENM Transmission (MW) Absolute Values -2024

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	1,119	1,437	1,504	1,402	1,217	1,024	849	756	836	1,158	1,289	1,437
2	1,147	1,473	1,500	1,347	1,163	1,038	846	675	761	1,156	1,321	1,431
3	1,123	1,452	1,470	1,335	1,115	987	801	616	705	1,130	1,338	1,404
4	1,111	1,427	1,405	1,300	1,124	917	739	579	662	1,105	1,325	1,369
5	1,112	1,425	1,333	1,251	1,093	876	688	524	631	1,098	1,290	1,341
6	1,106	1,432	1,310	1,221	1,019	838	617	488	609	1,089	1,246	1,345
7	1,112	1,435	1,283	1,138	877	732	517	408	583	1,061	1,163	1,326
8	1,107	1,407	1,194	964	830	736	444	353	482	952	1,103	1,230
9	1,042	1,300	1,125	955	865	748	457	390	498	861	995	1,168
10	985	1,271	1,129	970	901	785	420	396	506	862	940	1,070
11	1,052	1,274	1,114	951	896	798	380	397	481	821	990	1,072
12	1,106	1,271	1,130	975	925	844	369	395	498	794	1,023	1,065
13	1,152	1,284	1,136	1,007	963	830	367	446	555	827	1,042	1,099
14	1,151	1,295	1,146	1,056	1,029	850	394	539	625	830	1,117	1,135
15	1,162	1,288	1,136	1,113	1,112	898	484	642	695	870	1,116	1,156
16	1,175	1,255	1,163	1,169	1,171	955	631	725	772	920	1,115	1,149
17	1,136	1,286	1,226	1,212	1,225	983	765	803	878	957	1,115	1,150
18	1,114	1,311	1,306	1,248	1,268	1,065	869	830	947	1,004	1,213	1,249
19	1,148	1,332	1,355	1,267	1,230	1,075	957	866	1,029	1,121	1,245	1,330
20	1,183	1,389	1,423	1,328	1,245	1,079	1,044	939	1,079	1,178	1,282	1,374
21	1,184	1,432	1,451	1,377	1,319	1,057	1,079	982	1,093	1,161	1,275	1,423
22	1,171	1,462	1,461	1,449	1,365	1,067	1,018	989	1,038	1,139	1,288	1,444
23	1,159	1,453	1,479	1,452	1,322	1,074	971	912	972	1,096	1,302	1,470
24	1,140	1,468	1,490	1,406	1,250	1,086	910	819	922	1,068	1,302	1,443

Wind Max Output

Wind Max Output

PNM Exhibit JCA-3: 2025 Comparison of Transmission Loading and PNM Firm Load

Average PNM Firm Load - 2025

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	1,256	1,141	1,078	1,001	1,012	1,193	1,227	1,255	1,074	996	1,061	1,159
2	1,238	1,124	1,066	983	987	1,148	1,181	1,211	1,043	976	1,042	1,140
3	1,234	1,116	1,066	976	973	1,111	1,148	1,179	1,021	965	1,029	1,129
4	1,235	1,115	1,075	981	976	1,099	1,138	1,168	1,019	970	1,028	1,127
5	1,253	1,135	1,105	1,015	1,001	1,107	1,151	1,185	1,039	998	1,044	1,147
6	1,301	1,182	1,163	1,069	1,019	1,111	1,159	1,206	1,085	1,058	1,087	1,191
7	1,374	1,254	1,196	1,070	1,014	1,137	1,180	1,213	1,085	1,078	1,149	1,253
8	1,404	1,257	1,165	1,048	995	1,168	1,214	1,238	1,086	1,054	1,131	1,265
9	1,357	1,210	1,112	1,011	978	1,201	1,259	1,279	1,093	1,026	1,090	1,232
10	1,296	1,154	1,065	981	972	1,256	1,320	1,343	1,110	1,005	1,053	1,173
11	1,246	1,103	1,026	964	989	1,321	1,373	1,396	1,148	997	1,031	1,120
12	1,208	1,069	1,003	966	1,016	1,397	1,448	1,489	1,204	1,019	1,018	1,090
13	1,189	1,052	994	988	1,052	1,488	1,538	1,582	1,273	1,059	1,022	1,078
14	1,190	1,051	1,003	1,014	1,096	1,579	1,628	1,670	1,360	1,106	1,035	1,083
15	1,204	1,076	1,032	1,055	1,154	1,651	1,701	1,755	1,440	1,155	1,073	1,113
16	1,246	1,119	1,082	1,104	1,220	1,703	1,757	1,816	1,496	1,223	1,131	1,164
17	1,323	1,188	1,147	1,172	1,271	1,739	1,796	1,857	1,525	1,270	1,190	1,233
18	1,421	1,254	1,201	1,213	1,321	1,741	1,767	1,811	1,510	1,234	1,232	1,321
19	1,457	1,312	1,259	1,228	1,322	1,707	1,709	1,744	1,467	1,275	1,233	1,343
20	1,454	1,305	1,277	1,248	1,337	1,659	1,661	1,688	1,430	1,259	1,218	1,338
21	1,444	1,299	1,250	1,205	1,287	1,581	1,585	1,598	1,355	1,211	1,205	1,336
22	1,406	1,266	1,201	1,141	1,213	1,468	1,467	1,482	1,265	1,150	1,177	1,300
23	1,351	1,217	1,151	1,077	1,132	1,358	1,359	1,369	1,184	1,083	1,137	1,251
24	1,293	1,166	1,104	1,026	1,062	1,261	1,271	1,282	1,112	1,030	1,094	1,198

Summer Peak Load

Transmission Path 48 (MW) Absolute Values - 2025

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	737	631	593	488	407	567	673	553	564	439	448	628
2	704	636	632	494	420	568	655	593	562	475	484	645
3	717	619	637	453	452	554	651	653	586	508	468	645
4	765	609	595	413	488	600	670	740	622	539	461	652
5	839	608	551	441	540	690	633	807	611	564	463	633
6	900	597	569	440	499	601	647	866	722	521	487	637
7	836	585	585	505	501	506	441	684	536	468	513	615
8	838	581	721	627	628	502	367	411	326	465	544	672
9	645	690	858	654	560	444	383	374	355	598	648	826
10	627	720	879	734	615	458	384	367	417	567	650	732
11	614	686	883	770	640	469	355	283	372	554	648	717
12	604	729	865	793	602	448	318	223	387	583	618	728
13	608	809	930	830	615	414	293	245	376	633	626	687
14	731	818	938	903	666	400	271	238	312	712	620	790
15	751	828	1,039	874	655	419	318	275	336	776	624	821
16	762	887	1,042	849	647	488	357	310	410	765	575	747
17	596	756	965	769	610	578	368	329	364	489	424	430
18	568	482	631	437	449	401	375	396	494	368	390	428
19	545	515	632	397	372	452	486	434	420	420	380	479
20	597	553	742	414	356	503	463	392	348	499	466	541
21	618	578	771	418	331	514	460	453	327	506	468	559
22	634	578	739	383	333	525	479	429	342	526	468	559
23	659	593	681	392	352	508	531	556	483	429	467	597
24	703	609	619	425	389	495	592	564	528	430	421	599

Path 48 Max Loading

ENM Transmission (MW) Absolute Values -2025

Hour \	1	2	3	4	5	6	7	8	9	10	11	12
1	1,109	1,398	1,559	1,172	866	905	735	967	697	1,093	1,339	1,568
2	1,131	1,386	1,588	1,193	874	833	677	923	669	1,043	1,310	1,547
3	1,129	1,336	1,606	1,182	842	786	679	837	641	975	1,305	1,524
4	1,062	1,303	1,567	1,144	804	707	701	791	601	914	1,271	1,499
5	982	1,283	1,510	1,064	753	667	705	769	580	881	1,219	1,488
6	946	1,284	1,455	1,014	732	625	646	723	539	836	1,173	1,437
7	940	1,250	1,370	933	669	545	519	589	477	849	1,131	1,412
8	940	1,186	1,211	847	595	521	460	436	396	792	1,015	1,300
9	879	1,022	1,140	889	611	543	489	409	394	749	860	1,087
10	825	995	1,173	896	658	544	480	403	425	758	841	1,021
11	882	1,031	1,154	928	687	539	427	341	449	774	893	1,118
12	937	1,085	1,141	971	680	551	406	302	486	812	887	1,138
13	1,047	1,157	1,190	1,023	716	589	429	307	546	878	899	1,197
14	1,174	1,199	1,251	1,078	774	663	496	368	603	917	945	1,303
15	1,213	1,231	1,297	1,083	860	776	584	464	649	947	941	1,293
16	1,248	1,258	1,321	1,104	901	906	686	566	697	977	957	1,260
17	1,293	1,347	1,387	1,069	911	963	757	635	702	991	995	1,228
18	1,297	1,306	1,456	1,013	906	964	830	786	643	954	1,070	1,267
19	1,282	1,317	1,473	980	856	998	822	872	717	1,059	1,168	1,366
20	1,274	1,353	1,537	1,038	917	974	833	900	826	1,163	1,246	1,423
21	1,256	1,373	1,549	1,072	1,002	988	846	904	845	1,199	1,249	1,469
22	1,251	1,375	1,542	1,107	1,058	990	785	905	826	1,220	1,221	1,481
23	1,198	1,355	1,591	1,129	983	1,038	815	894	798	1,224	1,266	1,493
24	1,145	1,334	1,607	1,125	900	1,010	769	909	761	1,168	1,335	1,527

Wind Max Output

Wind Max Output

PNM Exhibit JCA-4

Incremental Cost Test Formula and Rate Derivation for Data Center Large Power Schedule 37B

Is contained in the following 2 pages.

PNM Exhibit JCA-4 : Incremental Cost Test Formula and Rate Derivation for Data Center Large Power Schedule 37B

	(1)	(2)	(3)		(4)	(5)
		Incremental Costs to Serve New 75MW @90% LF Customer				
1	Source:		**$/Yr**		**$/kWh**	
2	(a) = Est. RR (26-0000114)	Production Revenue Requirements of Incremental Unit(s)	$ 8,796,909	$	0.014848	
3	(b) = Est. RR (26-0000114)	Transmission Revenue Requirements of Incremental Unit(s)	$ 10,605,971	$	0.017902	
4	(c) = Est. RR (26-0000114)	Fuel Revenue Requirements of Incremental Unit(s)	$ 20,187,006	$	0.034073	
5	MLT-5, page 2, col. W, row 11 through row 19	Incremental Customer Related Costs	$ 355,468	$	0.000600	
6	(e)= (a) through (d)	Total Incremental RR	$ 39,945,354	$	0.067423	
7						
8	(f)= Estimated annual Usage	Annual Incremental Load in kWh (75MW @90% LF)			592,461,768	
9						
10	(g) = (e)/(f)	Unit Cost of Incremental Load		$	0.067423	
11						
12			Allocation of Total System Resources (Test Period)		Allocation of Incremental Resources Only	Total Incremental Cost (Max of)
	Source For Total System Resources:		(A)		(B)	(C)= Max [(A), (B)]
13	MLT-5, page 2, col. W, row 2+row 4+row 5	Current Resources Average Cost - Non-Fuel Production	$ 0.033000	$	0.014848	$ 0.033000
14	MLT-5, page 2, col. W, row 6+row 10	Current Resources Average Cost - Non-Fuel Transmission	$ 0.014227	$	0.017902	$ 0.017902
15	JCA-4, page 2, col [J], row 16	Current Resources Average Cost - FPPCAC	$ 0.015118	$	0.034073	$ 0.034073
16		Current Customer Related Costs	$ -	$	0.000600	$ 0.000600
17		Total Incremental Cost Rate $/kWh	$ 0.062344	$	0.067423	***$ 0.085574***
18						
19			**Rate Design and Proof of Revenue**			
20			**Determinants**		**Proposed Rate**	**Proof of Revenue**
21		Summer Customers	3	$	29,622.34	$ 88,867
22		Summer On-Peak kWh	55,912,353	$	0.0078358	$ 438,116
23		Summer Off-Peak kWh	93,012,463	$	0.0038231	$ 355,595
24		Summer Billable kW	224,826	$	39.46	$ 8,871,653
25		Summer Billable RkVA	0	$	-	$ -
26		Non-Summer Customers	9	$	29,622.34	$ 266,601
27		Non-Summer On-Peak kWh	164,634,173	$	0.0060761	$ 1,000,332
28		Non-Summer Off-Peak kWh	278,902,779	$	0.0038231	$ 1,066,270
29		Non-Summer Billable kW	674,478	$	27.32	$ 18,425,041
30		Non-Summer Billable RkVA	0	$	-	$ -
31		Total	592,461,768			$ 30,512,475
32					$/kWh	
33		Estimated Fuel Revenue	592,461,768	$	0.0340731	$ 20,187,006
34						
35					Total Revenue Requirement	$ 50,699,481

PNM Exhibit JCA-4 Page 2 of 2

Calculation of Fuel Rates based on Revised Voltage Class Adjustment Factors - Test Period Proof of Revenue Including Rate Schedules 37B/38B

Line No.	Description	Value	Notes
1	Fuel Costs	$ 134,138,322	*[A]*
2	Consolidated kWh at Meter (Non-Renewable)	8,592,660,176	*[B]*
3	Average Fuel Rate	$0.0156108	*[C] = [A] / [B]*

Consolidated Class Fuel Allocations

Line No.	Rate Class	Voltage Class	kWh at Meter-Cycle Sales *[D]*	Non-Renewable % *[E]*	Non-Renewable Energy kWh *[F]= [D] * [E]*	Cumulative Loss Factor *[G]*	kWh at Generator *[H] = [F] * [G]*	Voltage Class Adjustment Factors *[I] = [G] / [G] TOTAL*	Fuel Rate per kWh *[J] = [C] * [I]*	Fuel Revenue by Rate Class *[K] = [F] * [J]*
4	1 - Residential	Sec. Dist	3,392,380,292	81.58%	2,767,377,446	1.0771	2,980,874,680	1.0149394	$0.0158440	$43,846,379
5	2 - Small Power	Sec. Dist	957,006,510	81.58%	780,690,254	1.0771	840,918,833	1.0149394	$0.0158440	$12,369,271
6	3B, 3C, 3D, 3E, 3F - General Power	Sec. Dist	1,930,323,392	81.58%	1,574,685,902	1.0771	1,696,169,542	1.0149394	$0.0158440	$24,949,352
7	4B - Large Power	Pri. Dist	1,000,356,838	81.58%	816,053,836	1.0535	859,743,781	0.9926931	$0.0154967	$12,646,171
8	5B - Large Service for Customers >=8,000kW	Subtransmission	0	81.58%	0	1.0312	0	0.9716277	$0.0151679	$0
9	10 - Irrigation	Sec. Dist	24,480,916	81.58%	19,970,619	1.0771	21,511,310	1.0149394	$0.0158440	$316,415
10	11B - Wtr/Swg Pumping	Pri. Dist	166,836,465	81.58%	136,098,972	1.0535	143,385,448	0.9926931	$0.0154967	$2,109,090
11	15B - Universities 115 kV	Transmission	73,221,947	81.58%	59,731,736	1.0278	61,392,278	0.9684415	$0.0151181	$903,033
12	30B - Manuf. (30 MW)	Substation	729,887,686	81.58%	595,415,179	1.0371	617,480,787	0.9771660	$0.0152543	$9,082,669
13	33B - Large Service for Station Power	Transmission	10,661,166	81.58%	8,696,982	1.0278	8,938,758	0.9684415	$0.0151181	$131,482
14	35B - Large Power Service >=3,000kW	Substation	304,623,175	81.58%	248,500,237	1.0371	257,709,456	0.9771660	$0.0152543	$3,790,708
15	36B - Special Service -Renw. Energy Res.	Transmission	1,067,899,832	100.00%	1,067,899,832	1.0278	1,097,587,447	0.9684415	$0.0151181	$16,144,669
16	3XB - Data Center/Large Power at Transm.	Transmission	592,461,768	81.58%	483,308,236	1.0278	496,744,205	0.9684415	$0.0151181	$7,306,726
17	6 - Private Lighting	Sec. Dist	11,427,648	81.58%	9,322,250	1.0771	10,041,441	1.0149394	$0.0158440	$147,702
18	20 - Streetlighting	Sec. Dist	30,534,240	81.58%	24,908,695	1.0771	26,830,347	1.0149394	$0.0158440	$394,654
19	Totals		10,292,101,875		8,592,660,176	1.0613	9,119,328,314	1.0000000	$0.0156108	$134,138,322

PNM Exhibit JCA-5

Derivation of Non-Fuel Rates for Large Power at Transmission Service Schedule 38B

Is contained in the following 1 page.

PNM Exhibit JCA-5 : Derivation of Non-Fuel Rates for Large Power at Transmission Service Schedule 38B

	(1)	(2)		(3)	(4)	(5)
1		**Costs to Serve New 75MW @90% LF Customer per the COST**				
2	**Source:**	**Revenue Requirement Component**		**$/Yr**		
3	MLT-5, page 2, col. W, row 2	Production-Demand	$	12,842,080		
4	MLT-5, page 2, col. W, row 4	Production-Energy-Non-Fuel	$	2,265,034		
5	MLT-5, page 2, col. W, row 5	Storage-Production-Demand	$	4,443,943		
6	MLT-5, page 2, col. W, row 6	Storage-Transmission-Demand	$	2,992,651		
7	MLT-5, page 2, col. W, row 10	Transmission-Demand	$	5,436,026		
8	MLT-5, page 2, col. W, row 11 through row 19	Distribution-Customer	$	355,468		
9		Total Annual RR from COST	$	28,335,201		
10						
11						
12	Calculated	Annual Load in kWh (75MW @90% LF)		592,461,768		
13						
14						
15		**Rate Design and Proof of Revenue**				

16	**Rate Design Development**	**Determinants**		**Proposed Rate**		**Proof of Revenue**
17	Summer Customers	3	$	29,622.34	$	88,867
18	Summer On-Peak kWh	55,912,353	$	0.0078358	$	438,116
19	Summer Off-Peak kWh	93,012,463	$	0.0038231	$	355,595
20	Summer Billable kW	224,826	$	36.31	$	8,164,021
21	Summer Billable RkVA	0	$	-	$	-
22	Non-Summer Customers	9	$	29,622.34	$	266,601
23	Non-Summer On-Peak kWh	164,634,173	$	0.0060761	$	1,000,332
24	Non-Summer Off-Peak kWh	278,902,779	$	0.0038231	$	1,066,270
25	Non-Summer Billable kW	674,478	$	25.14	$	16,955,399
26	Non-Summer Billable RkVA	0	$	-	$	-
27	**Total**	**592,461,768**			**$**	**28,335,201**
28						
29						
30						
31						

PNM Exhibit JCA-6

Large Power at Transmission Service
Schedule 38B Tariff

Is contained in the following 3 pages.

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 38B

LARGE POWER AT TRANSMISSION SERVICE ≥ 30,000 KW MINIMUM

APPLICABILITY: The rates on this schedule are available to any retail customer, who contracts for a definite capacity commensurate with the customer's normal requirements but in no case less than 30,000 kW of capacity and who takes service directly from PNM's transmission system at 115 kV. The customer's monthly minimum demand under this schedule shall be 30,000 kW.

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

TYPE OF SERVICE: The service available under this schedule shall be three-phase service delivered at the Company's available transmission voltage of 115 kV.

The customer must sign a facilities contract or appropriate line extension agreement for any transmission or distribution cost incurred by the Company for the customer not paid prior to energization and not covered through rates on this tariff. Credit support (e.g., letter of credit or guaranty) and liquidated damages provisions will be included in the facilities contract or line extension agreement unless otherwise agreed to by the Company. All modifications to the facilities contract or line extension agreement must be in writing and executed as a supplement to the respective agreement.

SUBSTATION EQUIPMENT: All substation and distribution transformers, the necessary structures, voltage regulating devices, lightning arrestors, and accessory equipment required by the customer in order to utilize the Company's service at 115 kV shall be installed, paid for, owned, operated, and maintained by the customer.

The customer shall also provide, at customer's sole expense, suitable protective equipment and devices so as to protect the Company's system and service, and other electric users, from disturbances or faults that may occur on the customer's system or equipment.

The customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. The customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on the Company's system.

SUMMER MONTHS: The billing months of June, July, and August

NON-SUMMER MONTHS: The billing months of September through May

TIME-OF-USE ("TOU") RATE

TOU ON-PEAK HOURS: Year-round 8:00am - 8:00pm Mon - Fri (60 hours per week)

TOU OFF-PEAK HOURS: All hours other than On-Peak

TOU MONTHLY CHARGE: Absent any consumption, the monthly minimum charge is the customer charge plus the total demand multiplied by the on-peak demand charge.

	Summer	Non-Summer

Advice Notice No. 667

/s/ Kyle T. Sanders
Kyle T. Sanders
Vice President, Regulatory

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 38B

LARGE POWER AT TRANSMISSION SERVICE ≥ 30,000 KW MINIMUM

(A)	CUSTOMER CHARGE: (Per Metered Account)	$29,622.34/Bill	$29,622.34/Bill
(B)	ON-PEAK DEMAND CHARGE: (For All Billing Demand kW During On-Peak Period)	$36.31/kW	$25.14/kW
(C)	ENERGY CHARGE:		
	On-Peak kWh	$0.0078358/kWh	$0.0060761/kWh
	Off-Peak kWh	$0.0038231/kWh	$0.0038231/kWh

RATE RIDERS, CHARGES, AND ADJUSTMENTS

(D) POWER FACTOR ADJUSTMENT: The above rates are based on a power factor of 90 percent or higher and the Company will supply, without additional charge, a maximum of 0.48 kVAR (Reactive Kilovolt Amperes) per kW of Total Demand. The monthly bill will be increased $0.27 for each kVAR in excess of the allowed 0.48 kVAR per kW of Total Demand.

(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.

(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 federal income taxes) payable by the Company 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.

DETERMINATION OF TOTAL DEMAND: The total demand shall in no event be less than the highest of the following: (a) the actual metered on-peak kW demand, (b) 50 percent of the highest metered on-peak kW demand during the preceding 11 months, (c) the minimum demand defined on this Schedule, or (d) the contracted minimum kW demand should it exceed the minimum demand provided for on this Schedule.

Metering shall normally be at the transmission service voltage. The Company reserves the right to meter at the secondary voltage of the customer's transformers different voltage level, in which event the metered kWh, kW demand, and kVAR shall be multiplied by the appropriate factor to allow for losses.

Where highly fluctuating or intermittent loads which are impractical to determine properly (such as welding machine, electric furnaces, hoists, elevators, X-rays, and the like) are in operation by the

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RATE NO. 38B

LARGE POWER AT TRANSMISSION SERVICE ≥ 30,000 KW MINIMUM

customer, the Company reserves the right to determine the billing demand by increasing the 15-minute measured maximum demand and kVAR by an amount equal to 65 percent of the nameplate rated kVA capacity of the fluctuating equipment in operation by the customer.

INTERRUPTION OF SERVICE: Please refer to PNM Rule 12.

ACCESSIBILITY: Equipment used to provide electric service must be physically accessible. The metering must be installed on each service location at a point accessible to Company personnel at any time.

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.

LIMITATION OF RATE: Electric service under this Schedule is not available for standby service, is not available to customers served in the downtown area of Albuquerque when served by the underground network system, and shall not be resold or shared with others.

RULES AND REGULATIONS: Service will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These Rules and Regulations are available at the Company's office and are on file with the New Mexico Public Regulation Commission. These Rules and Regulations are a part of this Schedule as if fully written herein.

Advice Notice No. 667

/s/ Kyle T. Sanders
Kyle T. Sanders
Vice President, Regulatory

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. 667	)	**Docket No. 26-0000XXX**
PUBLIC SERVICE COMPANY OF NEW MEXICO,	)	
Applicant.	)	

AFFIRMATION

I, Julio C. Aguirre, submit this unsworn affirmation pursuant to Rule 1.2.2.35(A)(3) and state, upon penalty of perjury under the laws of the State of New Mexico, that I have read the foregoing Direct Testimony and that the statements contained therein are true and correct based on my personal knowledge, information and belief.

Dated: November 24, 2026.

/s/ *Julio C. Aguirre*
JULIO C. AGUIRRE

GCG#536037