BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	))))))))	**Case No. 22-00058-UT**

DIRECT TESTIMONY

OF

MARIO A. CERVANTES

October 3, 2022

NMPRC CASE NO. 22-00058-UT
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MARIO A. CERVANTES

WITNESS FOR

PUBLIC SERVICE COMPANY OF NEW MEXICO

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Self-Verification

DIRECT TESTIMONY
OF MARIO A. CERVANTES
NMPRC CASE NO. 22-00058-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Mario A. Cervantes. I am the Director of Customer Experience for Public Service Company of New Mexico ("PNM"). My address is 414 Silver Avenue, SW, Albuquerque, New Mexico 87102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS

A. Please see PNM Exhibit MAC-1 for my educational background and professional qualifications.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF CUSTOMER EXPERIENCE.

A. In my role, I am primarily responsible for the development and execution of the Customer Experience strategy for PNM. My areas of responsibility include the PNM Contact Center, Voice of the Customer and Insights, Digital Experience, Revenue Operations, and Low-Income Programs.

Q. WHY IS GRID MODERNIZATION NECESSARY TO IMPROVE THE PNM CUSTOMER EXPERIENCE?

A. PNM's proposed grid modernization is critical to improving customer experience and engaging customers as partners in moving toward a carbon-free future. Through outreach, PNM received consistent feedback regarding the need for more detailed customer energy usage information and more advanced tools to manage bills. PNM's grid modernization plan will provide a pathway to enhancing customers' experience by providing granular energy usage data through the Customer Energy Management Platform. It will also give customers new bill management tools, including the ability to pre-pay, set their own bill date, and set customized alerts about usage or rates. In the longer term, the grid modernization improvements will allow customers to better understand their energy options for distributed energy resource adoption, efficiency programs, and time-of-day rates. The grid modernization investments PNM proposes in this application are important steps toward the customer empowerment that will be necessary to meet the state's environmental goals while also maintaining system reliability and affordability.

Q. PLEASE STATE THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my testimony is to: 1) describe the advanced metering infrastructure ("AMI") bill management enhancements; 2) describe the Customer Energy Management Platform features and benefits; 3) describe call center staffing needs as AMI is deployed; and 4) describe how PNM plans to comply with New Mexico Public Regulation Commission ("NMPRC" or "Commission") regulations and its request for a limited variance.

II. AMI BILL MANAGEMENT ENHANCEMENTS

Q. HOW DOES AMI ENABLE CUSTOMERS TO MANAGE THEIR BILLS?

A. The AMI system collects customer interval energy usage data daily and stores it in the Meter Data Management System ("MDMS"). The daily usage data updates are combined with historical usage data and made available to customers through the Customer Energy Management Platform. This Platform provides customers information regarding their hourly, daily, monthly, and annual energy usage. Customers will have insight into their total usage and peak demand for each bill period. The Customer Energy Management Platform will also apply the customer's rate to estimate total bill costs at the end of the billing period.

The primary function of the AMI meter is to measure the amount of electricity used over specific time intervals for billing purposes. For example, customers enrolled in the whole-home electric vehicle ("WHEV") rate can use the interval data by segmenting the consumption data into the time-of-day increments in alignment with that rate structure. If the rate structure changes over time, the interval data supports updates to the time-of-day parameters, remotely, without reprogramming meter registers.

AMI meters have additional capabilities to support customer distributed energy resource ("DER") adoption and can be remotely configured to measure bi-directional (delivered and received) and/or time-of-day energy consumption in kilowatt hours ("kWh") and demand in kilowatts ("kW"). An AMI meter that is configured for bi-directional energy measurement can also measure net energy provided to PNM's grid from customers with distributed resources. Energy consumption data will be recorded in 15-minutes intervals as a default or in 5-minute intervals for EV or DER customers, as referenced in the Direct Testimony of PNM witness Jonathan Hawkins.

Q. DESCRIBE HOW AMI WILL IMPROVE CUSTOMERS' BILLING AND PAYMENTS EXPERIENCE.

A. AMI will provide data to the Customer Energy Management Platform to give customers insights and options to manage electricity bills. This includes providing energy and billing information on a next day basis with customer configurable notifications based on forecasts using the AMI interval data. AMI will also enable new rate schedule options related to time-of-day and electric vehicle charging that will encourage customer behavior modifications and may save customers money. PNM witness Stella Chan discusses a proposed beneficial rate structure that customers will be able to utilize with AMI deployment. Once deployed, AMI will also enable PNM to develop and provide customers with new bill-payment programs and options, such as pick-your-own due date and prepay. Customers will be empowered to manage their electricity usage and costs, thereby participating in efforts to transition to carbon-free in ways that are beneficial to the customer. Customer service interactions with PNM such as starting and stopping of service, restarting service, and outage reporting can be done remotely and proactively with AMI, making experiences like these much easier and more convenient. Additionally, through the Customer Energy Management Platform, customers will have access to their energy breakdown to see exactly where they are using the most energy and adjust their habits accordingly to prevent unexpectedly high bills in the future, should the customer be enrolled in a time-of-day rate.

Q. HOW WILL LOW-INCOME CUSTOMERS BENEFIT FROM PROGRAMS AND SERVICES ENABLED BY AMI?

A. According to the U.S. Census Bureau, 18.4% of New Mexicans are living below the Federal Poverty Level ("FPL"). This is 7% higher than the national average of 11.4%. Many observers believe the FPL is set too low and does not adequately measure economic well-being. To address those living above the FPL, but still struggling financially, PNM has defined low-income customers as having an income below 200% of the FPL. This is consistent with industry standards and other programs offered by PNM, including the PNM Covid Relief Fund and energy efficiency programs. Applying this broader definition, roughly 41% of PNM customers are considered low-income, and may struggle with their energy bills as a proportion of their income.

The Department of Energy ("DOE") states "Low-income households face a disproportionately higher energy burden. Energy burden is defined as the percentage of gross household income spent on energy costs."[1] According to the National Conference of State Legislatures, "National data shows that on average, low-income households pay nearly 9% of their income in energy costs—three times more than non-low-income households. An estimated 25% of households have a high energy burden, considered to be above 6% of household income. An additional 13% of American households have a severe energy burden of paying more than 10% of their income on energy."[2] Because of the elevated energy burden for PNM's low-income customers, addressing price sensitivity through payment options and programs is a crucial benefit of AMI.

AMI-enabled services offered through the Customer Energy Management Platform, such as usage alerts, will notify customers when their electricity consumption exceeds a pre-determined threshold. This will help increase customer

[1] https://www.energy.gov/eere/slsc/low-income-community-energy-solutions
[2] https://www.ncsl.org/research/energy/energy-justice-and-the-energy-transition.aspx

awareness and prevent higher than expected bills, which will allow customers to plan for and better control their energy spending. Other payment programs, like prepay, are also beneficial to low-income customers because it allows customers to pay ahead for future energy consumption. According to a recent report by E Source's Prepay Energy Working Group ("PEWG"), provided as PNM Exhibit MAC-2, low-income customers are among the groups most interested in a prepay program because prepay enables them to set money aside, avoid fees and penalties, and practice cash management and budgeting. Another AMI enabled payment program is pick-your-own due date which allows customers to align their electric bill due date with their pay cycle or when funds are available to them.

Q. HOW DOES PNM DETERMINE WHO IS A LOW-INCOME CUSTOMER FOR PURPOSES OF EVALUATING CUSTOMER BENEFITS?

A. PNM determines low-income customers through the incorporation of FPL at the 200% threshold and using Experian customer data. The FPL provides income levels based on the number of household members.[3] The Experian data provides estimates for both income levels and number of household members for PNM's residential customers. These Experian estimates are compared to the 200% FPL first by number of household members, then by estimated income. Based on the

[3] See the Federal Poverty Guideline at https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines

number of household members, customers with an estimated income at or below the 200% threshold are considered low-income. Customers making more than the 200% threshold are not considered low-income.

Q. HOW WILL AMI ENABLE NEW CUSTOMER PAYMENT OPTIONS?

A. The AMI system will enable customers to personalize their bill payment experience. For example, customers will be able to elect specific dates for monthly billing ("pick-your-own-due date"). Allowing customers to pick their own due dates improves customer satisfaction because it puts the customer in control. AMI will also enable customers to choose payment programs like prepay, which allows customers to pay for electricity they need before they use it. Prepaid electric plans allow customers to have more control over what they pay, since they only pay for as much electricity as they need. A pre-pay program requires development and programming that can only be performed once AMI is implemented, therefore PNM expects these to be available to customers in year 2 of AMI deployment.

Q. CAN PNM'S EXISTING CUSTOMER BILLING SYSTEM FULLY SUPPORT RATES AND PRICING THAT AMI TECHNOLOGY WILL ENABLE?

A. PNM's current Customer Information System ("CIS") billing system can support rates and pricing programs that use two different tiers (*e.g.*, off-peak, on-peak). However, more complex rate structures or alternative time-of-day rate structures with more than two tiers would likely require feasibility studies, impact analysis testing, and potential changes to core billing modules (*e.g.*, charge calculation process).

If PNM identifies a need to overhaul its CIS billing system in the future to accommodate more complex rate structures, it will address any billing system changes and additional functionality in the rate case associated with any proposed new rates or programs triggering the need.

Q. WHAT ENHANCEMENTS OR CHANGES WILL PNM'S CUSTOMER BILLING SYSTEM NEED TO PROVIDE CUSTOMERS WITH THE FULL RATE AND PRICING BENEFITS AMI OFFERS?

A. PNM's current CIS is not designed to receive, store, and bill using the very large amount of 15-minute, or smaller, interval data that AMI will collect. For context, PNM's existing CIS generates bills based on one read per account per billing cycle. PNM will need to incorporate an MDMS system to validate, store, and organize the AMI meter data for billing. The MDMS verification, estimation and error correction process will identify problematic data from the meter data collection systems before it reaches other utility systems and will provide tools for addressing quality issues according to a utility's specific best practice rules and meter-specific parameters. The MDMS will also act as the definitive source for meter read data with synchronized interfaces with the CIS system. The MDMS will organize the interval meter data into CIS-compatible billing determinants to prepare bills aligning with customer specific tariffs. The MDMS and related system integration with the CIS and other systems is described in Mr. Hawkins' testimony.

III. CUSTOMER ENERGY MANAGEMENT PLATFORM

Q. HOW DID PNM IDENTIFY CUSTOMER EXPECTATIONS FOR SOLUTIONS AND BENEFITS PROVIDED BY AMI AND THE CUSTOMER ENERGY MANAGEMENT PLATFORM?

A. In May 2022, PNM conducted surveys with residential and small business customers on grid modernization. In those surveys, 55% of residential and 53% of small business respondents indicated that having detailed usage and cost information was extremely or very important, while 54% of residential and 48% of small business respondents indicated that having tools to manage usage was extremely or very important. AMI and the associated Customer Energy Management Platform will enable PNM to meet all of these customer needs. Please see PNM Exhibit JAR-4 for the results of this survey.

Q. PLEASE DESCRIBE THE CUSTOMER ENERGY MANAGEMENT PLATFORM.

A. The Customer Energy Management Platform is an internet-based platform accessible by customers via a personal computer, smart tablet, smartphone, or mobile application, that enables customers to access and interact with their energy-usage information collected by the AMI system. This Platform enables the exchange and display of granular energy-usage information based on the customer's AMI interval data. PNM's Customer Energy Management Platform will provide customers (or a customer designated authorized user) access to their granular usage data via intuitive web-based graphs and charts. Additionally, the Customer Energy Management Platform can be expanded in the future to provide analytic capabilities to support customer decisions regarding rate options, energy efficiency solutions, and rooftop solar.

Q. DOES PNM CURRENTLY PROVIDE ONLINE CUSTOMER ACCESS TO ACCOUNT MANAGEMENT SERVICES?

A. Yes. PNM currently offers a My Account portal for customer account management, and online billing information that also works on a mobile device. This system provides customers access to copies of their bill, payment options, and information on customer program offerings. However, the current My Account web portal does not have the ability to display AMI interval usage data and is not sufficient to address customers' needs and expectations. The new Customer Energy Management Platform, which will be accessible to the customer when they log into the existing My Account portal, is necessary to more fully leverage the AMI and other grid modernization capabilities for customers' benefit.

Q. PLEASE DESCRIBE HOW THE CUSTOMER ENERGY MANAGEMENT PLATFORM WILL HELP CUSTOMERS MANAGE THEIR MONTHLY BILL.

A. The Customer Energy Management Platform will be able to display the previous day's usage, as well as historical usage data that can provide forecasted monthly bill amounts and bill alerts based on customer-set thresholds. Customers will be able to compare current usage data to historical usage (*e.g.*, previous day, month, or year) to determine opportunities to conserve or shape their energy use and save money. Customers can set other alerts regarding time-of-day and peak-period. The Customer Energy Management Platform will also graphically present interval energy consumption and/or generation (kWh) and demand data (kW). Customers will be able to securely download large quantities of data to their personal computer using the Green Button data standard that is safeguarded by strong privacy protections and cybersecurity measures discussed in Mr. Hawkins' testimony. PNM's call center representatives will also be able to access the customer's meter data to assist customers with bill inquiries.

Q. PLEASE DESCRIBE OTHER FEATURES AND BENEFITS OF THE CUSTOMER ENERGY MANAGEMENT PLATFORM.

A. The Customer Energy Management Platform will include disaggregation technology where customer's energy consumption can be separated into different end uses (lighting, appliances, heating/air conditioning, EV chargers, etc.) through estimation algorithms. This will enable customers to have better insights into which devices and energy-usage patterns drive their monthly bills. PNM asked AMI and energy management platform vendors about this "disaggregation" capability as a result of stakeholder feedback during meetings in the Spring of 2022. The Customer Energy Management Platform will also provide access to outage information, such as outage notifications, restoration estimates, and confirmations regarding repair and power restoration or link to the existing Outage Map on PNM.com.

Q. PLEASE DESCRIBE THE LONGER TERM FEATURES AND BENEFITS OF THE CUSTOMER ENERGY MANAGEMENT PLATFORM THAT WILL BECOME AVAILABLE TO CUSTOMERS BEYOND THE SIX-YEAR IMPLEMENTATION PLAN PERIOD.

A. In the longer term, the Customer Energy Management Platform will include decision-support analytics. The decision-support analytics will be based on customer historical usage patterns to inform customers regarding whether to utilize potentially beneficial rates and programs, such as electric vehicle adoption and charging, energy efficiency solutions, rooftop solar and other evolving energy management options.

Q. DOES PNM EXPECT THE CUSTOMER ENERGY MANAGEMENT PLATFORM TO BE AVAILABLE PRIOR TO AMI IMPLEMENTATION?

A. PNM anticipates that the Customer Energy Management Platform will begin implementation after detailed technical planning activities are completed. Full implementation of the Customer Energy Management Platform will be completed within three years of the Commission's decision—approximately one year earlier than the completion of AMI meter rollout. Once the Customer Energy Management Platform is operational, customers who have an AMI meter will begin to have their detailed AMI interval usage data available through the Customer Energy Management Platform.

Customers that do not yet have an AMI meter will also have access to the Customer Energy Management Platform. However, the data and insight from the Customer Energy Management Platform will be limited to the monthly manual meter read data and monthly billing information.

Q. WILL THE CUSTOMER ENERGY MANAGEMENT PLATFORM ALLOW FOR CUSTOMER-AUTHORIZED THIRD-PARTY ACCESS TO ENERGY DATA?

A. Yes. PNM's Customer Energy Management Platform will include a feature which will enable a customer to authorize a third-party provider to securely download their energy usage data via the Green Button Connect standard.

Q. WHAT IS THE GREEN BUTTON CONNECT STANDARD?

A. Per Green Button Alliance, Green Button Connect is "is the energy-industry standard…for enabling easy access to, and secure sharing of, utility-customer energy- and water-usage data. Utilities providing standards-based Green Button customer-consumption and billing data can provide customers new data-driven services, programs, and platforms; digitally empowering customers with the ability to securely transfer their data to third-party solution providers who can further assist them in monitoring and managing energy or water usage."[4]

Q. PLEASE DESCRIBE THE TECHNOLOGY SOURCING PROCESS FOR PNM'S CUSTOMER ENERGY MANAGEMENT PLATFORM.

A. PNM issued a Request for Information ("RFI") for the Customer Energy Management Platform in June 2022. Five vendors responded to the RFI. The purpose of the RFI was to collect information, including high-level costs, associated with the development and hosting of a mobile-friendly customer energy management platform to display AMI usage data and enable PNM customers to analyze, understand and interact with their detailed electric usage. The RFI process was conducted concurrent with the AMI Request for Proposals ("RFP"), so that the responses from the AMI vendors along and the customer energy management

[4] https://greenbuttondata.org/

platform vendors can help inform the management platform RFP. PNM plans to issue an RFP for the Customer Energy Management Platform in early 2023, which will be accompanied by a detailed set of business and technical requirements. PNM expects to identify the most qualified vendor and award the Customer Energy Management Platform project in the third quarter of 2023. Contract execution and platform implementation will be contingent on the NMPRC approving this PNM Grid Modernization application.

Q. PLEASE DESCRIBE THE VENDOR SELECTION CRITERIA FOR THE CUSTOMER ENERGY MANAGEMENT PLATFORM.

A. The Customer Energy Management Platform RFI asked vendors to describe or illustrate how their customer energy management platform will offer 20 different features including, but not limited to: graphical representation of consumption and/or generation interval kWh data (usage or generation); graphical representation of demand data (kW) presentment for demand-billed customers; capability for customers to compare usage data to their historical usage (*e.g.*, previous month, previous year); ability to analyze all data in two views - chart and heat map; ability to electronically deliver energy usage reports; energy markers; disaggregation of end-use energy data (appliances, EV chargers, weather data, etc.); configurable threshold alerts; forecasting/high bill notifications; demand response program notifications; time-of-day and peak-period alerts; status of service; program sign-up; support for customers with multiple meters; and single login for multiple accounts. In addition to asking how each vendor's solution can provide the previously mentioned features, the RFP for the Customer Energy Management Platform will be accompanied by a detailed set of business and technical requirements. Vendors will also be required to answer questions and provide documentation pertaining to cybersecurity and how they protect customer personal identifiable information, as well as data that stored and in transit.

Q. WHAT WILL THE TOTAL O&M AND CAPITAL COST BE FOR THE IMPLEMENTATION AND ONGOING MAINTENANCE AND SUPPORT OF THE CUSTOMER ENERGY MANAGEMENT PLATFORM?

A. PNM is estimating the total operational and maintenance ("O&M") and capital cost to implement, support and maintain the Customer Energy Management Platform solution to be $7,647,000 ($7.1 million in O&M expenses and $520k in capital costs) in years 2 through 6 of the Implementation Plan.[5] The pricing model of the Customer Energy Management Platform includes an annual fee associated with licensing a vendor supported and managed cloud-based software solution, also known as a software as a service, or SaaS, solution. The costs also include two full-time employees to support and analyze data from the Customer Energy Management Platform and create new customer programs to meet the evolving

[5] The Implementation Plan is attached to the testimony of PNM witness Laura Sanchez as PNM Exhibit LES-3.

needs and expectations of customers. Details on the projected O&M and capital costs are reflected in table MAC-1 and MAC-2 below.

Table MAC-1

Customer Information & Analytics O&M Costs

O&M

Row Labels	Sum of 1	Sum of 2	Sum of 3	Sum of 4	Sum of 5	Sum of 6
Customer Information & Analytics	**-**	**1,390,214**	**1,404,781**	**1,420,003**	**1,435,911**	**1,452,534**
Cust Info & Analytics Support O&M	-	1,060,000	1,060,000	1,060,000	1,060,000	1,060,000
Customer Portal Management & Analytics Employees	-	323,714	338,281	353,503	369,411	386,034
Customer Portal Management & Analytics Employees Annual Employee Expenses (Flat)	-	6,500	6,500	6,500	6,500	6,500

Table MAC-2

Customer Information & Analytics Capital Costs

Capital

Row Labels	Sum of Total Year 1	Sum of Total Year 2	Sum of Total Year 3	Sum of Total Year 4	Sum of Total Year 5	Sum of Total Year 6
Customer Information & Analytics	**-**	**521,989**	**-**	**-**	**-**	**-**
Customer Information & Analytics Portals	-	311,711	-	-	-	-
Customer Information & Analytics Portals (40% PNM Labor)	-	210,277	-	-	-	-
Grand Total	**-**	**521,989**	**-**	**-**	**-**	**-**

IV. CALL CENTER STAFFING FOR AMI DEPLOYMENT

Q. DOES PNM EXPECT AN INCREASE IN CUSTOMER BILLING INQUIRIES INTO THE CONTACT CENTER AS A RESULT OF AMI BEING INSTALLED?

A. Yes. Given PNM's experience in previous major deployments of new customer facing technologies (*e.g.*, rollout of the PNM.com website in 2013), PNM anticipates call volumes will increase 10-15% beginning in the second year of meter deployment, when the AMI companion systems are deployed and operational. PNM expects the increased call volume will extend 12-18 months after the final year of the three-year meter deployment.

Q. WHAT TYPES OF CUSTOMER INQUIRIES DOES PNM EXPECT TO RECEIVE ONCE AMI IS INSTALLED?

A. PNM expects questions about the AMI opt-out process and billing inquiries when customers compare current bills to bills from prior summer or winter months before AMI deployment. PNM also expects customers will inquire about the new information that will become available via the Customer Energy Management Platform like granular usage data, bill management options, and other new features and benefits enabled by AMI.

Q. WILL THE PNM CONTACT CENTER HANDLE CALLS RELATED TO AMI INSTALLATION?

A. No. The selected AMI installation vendor will provide a customer service support line for customers inquiring about AMI installation matters. AMI installation matters may include customer inquiries regarding scheduling of AMI meter installation, request for scheduling changes, and other matters specific to meter installation. The AMI installation calls are not included in PNM's 10-15% estimated increase in call volume because they will be routed to the installation vendor's call center.

Q. WILL PNM NEED TO INCREASE STAFFING IN ITS CONTACT CENTER TO HANDLE THE ADDITIONAL CALL VOLUME AS A RESULT OF AMI INFRASTRUCTURE DEPLOYMENT?

A. Yes. PNM expects that staffing in the contact center will need to be temporarily increased by an additional 10-12%, or the equivalent of 8 FTE, to handle the expected increase in call volume. The additional staffing need was determined by assuming a 10-15% increase in call volume in the contact center workforce planning tool. PNM plans to utilize a temporary staffing solution concurrent with meter deployment and extending 12 months after the final year of the three-year meter deployment.

Q. WHAT WILL THE TOTAL O&M COST BE FOR THE EXPECTED STAFFING INCREASE TO HANDLE CUSTOMER AMI BILLING RELATED INQUIRES?

A. The estimated cost for an increase in 10-12% in staffing levels is approximately $529,000 annually over a four-year period to align with the expected increase in call center volume related to AMI deployment. The total cost for the four years is estimated to be at $2,116,000 as listed in Table MAC-3 below:

Table MAC-3

Customer Information & Analytics O&M Costs

O&M						
Row Labels	**Sum of 1**	**Sum of 2**	**Sum of 3**	**Sum of 4**	**Sum of 5**	**Sum of 6**
Advanced Metering	**-**	**496,394**	**517,562**	**539,682**	**562,797**	**-**
Call Center Support for deployment - temp labor	-	470,394	491,562	513,682	536,797	-
Call Center Support for deployment - temp labor Annual Employee Expenses (Flat)	-	26,000	26,000	26,000	26,000	-

V. COMPLIANCE WITH REGULATIONS AND REQUEST FOR LIMITED VARIANCE

Q. AFTER AMI IS INSTALLED, HOW WILL PNM COMPLY WITH THE DISCONNECTION PROVISIONS IN NMAC RULE 17.5.410?

A. To the extent necessary, PNM is requesting a variance from the provisions of NMAC Rule 17.5.410 implying that a utility employee will be sent to a customer's premises to discontinue service. Once the AMI is installed, PNM plans to disconnect customers remotely rather than manually. For customers that opt-out of AMI, the existing provisions of Rule 17.5.410 shall apply.

Two provisions of Rule 17.5.410.33 imply that a utility employee will be sent to the customer's premises to disconnect service. Rule 17.5.410.33(B) requires PNM to "communicate with a residential customer by telephone, mail if delivery to the residential service address can be verified, or personal contact" at least two days prior to discontinuance of service to (1) remind the customer of the pending discontinuance of service, (2) advise the customer of the potential availability of financial assistance, (3) obtain delinquent payment, (4) provide a reminder regarding winter moratorium protections. PNM will continue to comply with these provisions, but the communications will not take place during a utility employee visit to disconnect service.

Rule 17.5.410.33(B)(2) provides: "The utility employee who personally contacts a residential customer and the utility employee sent to discontinue utility services shall note any information from the residential customer that a person living in the residential customer's residence is seriously or chronically ill. Such information shall immediately be reported to a utility employee authorized to prevent discontinuance." After AMI installation, PNM does not plan to send a utility employee to a customer's premises to make personal contact or discontinue services, but PNM will continue with its existing notification processes within the fifteen-day and two-day notification periods prior to disconnection, by telephone and mail if delivery to the residential service address can be verified to ascertain whether to prevent disconnection. PNM also plans to enhance outbound calling efforts to reach customers before disconnection occurs. In doing so, PNM will continue to note any information from the residential customer that a person living in the residence is seriously or chronically ill and respond appropriately, as PNM does today. To the extent necessary, PNM requests a variance from Rule 17.5.410.33(B)(2) to allow PNM to attempt to make contact with customers prior to disconnection via phone.

Rule 17.5.410.33(B)(5) states: "*__The utility employee sent to discontinue utility service__* may be empowered to receive payment of delinquent bills, and upon receipt of approved payment method, shall cancel the discontinuance order." (emphasis added). After AMI is installed, PNM will disconnect customers remotely and does not plan to send employees to receive payment for delinquent bills. Therefore, to the extent necessary, PNM requests a variance from Rule 17.5.410.33(B)(5) to allow PNM to receive payment from AMI customers by phone rather than in person.

Q. WILL PNM NEED TO CHANGE ANY OF ITS CURRENT NMPRC APPROVED RATES AND RULES?

A. If the NMPRC approves PNM's Application, PNM will file an Advice Notice amending its current NMPRC approved Rule Nos. 8 and 20 to include necessary changes to PNM's billing, meter reading and disconnection processes.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

GCG#529865

MARIO A. CERVANTES

SUMMARY

Accomplished Customer Experience Executive with over 20 years combined experience in customer operations. Proven visionary and strategic leader with the unique ability to establish and execute strategic plans to accomplish key organizational objectives. Proven ability navigating and leading complex environments. Verifiable track record of leading and managing a diverse workforce at all levels, with the ability to quickly build genuine rapport with direct reports, peers, customers, vendors and executive leadership. Experience managing and leading projects and improving processes using continuous improvement methodologies.

KEY QUALIFICATIONS

- Strong knowledge of the Electric Utility industry
- Six Sigma certified
- Strategic leader
- MBA
- Experience managing multi-million-dollar budgets
- Strong knowledge of Public Regulation Commission rules and regulations
- Fluent in both English and Spanish
- Highly effective oral and written communication skills
- Highly skilled at process improvement and development

PROFESSIONAL EXPERIENCE

PNM RESOURCES **2012-Present**

Based in Albuquerque, N.M., PNM Resources is an energy holding company with consolidated operating revenues of $1.3 billion. PNM Resources serves electricity to more than 739,000 homes and businesses in New Mexico and Texas.

Director, Customer Experience

Responsible for the development and execution of the Customer Experience strategy for PNM. Responsible for the leadership and management of the PNM and TNMP Customer Experience and support teams. Responsible for accurate customer billing, effective credit and collections, voice of the customer and insights, digital experience, low-income programs and for ensuring incoming customer contacts are answered by staff within quality standards, agreed service levels, compliance and regulatory requirements.

Key Achievements

- Successfully developed and executed multi-year Customer Experience strategies focused on improvements to customer communications, employee engagement, power quality and reliability, customer service (digital and in-person), and billing and payments
- Led a COVID customer arrears strategy aimed at reducing customer arrears through the creation of new payment programs and solutions and customer awareness strategies
- Identify and work alongside Regulatory and legal teams on matters involving Customer Experience and Billing
- Aligned the rewards and recognition program to incentivize employees driving key organizational goals
- Assisted in the implementation of a new ACD/IVR phone system to allow for additional scalability, redundancy and additional efficiencies resulting in significant improvements to customer wait times and service levels
- Successfully implemented a digital channel strategy (chat, two-way texting, predictive IVR), which has resulted in a decrease in call volumes, increased digital channel adoption and improved customer satisfaction scores
- Implemented an employee training and development strategy, which resulted in record high customer satisfaction scores of 95%
- Mentored and developed several high performing employees into leadership positions
- Implemented a strategy to attract and retain higher skill level Customer Service Representatives

- Through the implementation of technology enhancements and an incentive programs increased customer paperless bill participation
- Developed and executed strategy aimed at improving customer billing accuracy

NUSENDA FEDERAL CREDIT UNION **2007-2012**

Call Center/Electronic Branch Operations Manager

Responsible for the leadership, direction, development, training and management of a 40+ seat Customer/Member Service, Lending and e-Channel Call Center Operation for the largest CU in the state of New Mexico.

Key Achievements

- Successfully led the transformation of the call center from a switchboard operation to a full service and sales operation.
- Improved employee satisfaction scores through strategies aimed at advancing employee development, career growth and recognition
- Developed and implemented performance metrics and targets that resulted in Service Level and member satisfaction improvements
- Introduced and implemented various call center technologies increasing employee productivity
- Developed and implemented a self- service strategy that contributed to the self-service adoption increase of 8%
- Implemented an enhanced IVR and skill-based routing process which resulted in improved call handling, service levels and member experience.
- Successfully implemented a call overflow support strategy resulting in improved SL's and disaster/crisis preparedness

WELLSFARGO **2006-2007**

Loan Servicing Operations Manager

Responsible for the leadership, coaching, development, and management of a loan research department. Directly responsible for departmental efficiencies, service levels, productivity, staff development and internal and external customer satisfaction.

Key Achievements

- Improved turnaround times for research requests using six sigma which resulted in a 25% increase in customer satisfaction
- Developed and implemented a performance measurement tool that increased productivity by 35% from the previous year, and brought cost savings of approximately 100k
- Identified new technology within operating systems that resulted in increased efficiency and improved workflows
- Developed and implemented balanced scorecards for front line and leadership staff focused on accountability and recognition
- Developed and implemented recognition programs resulting in improved employee satisfaction scores from 76% to 84%
- Identified and addressed gaps in communication by implementing daily huddles, monthly departmental meetings, and other communication strategies
- Received numerous nominations and awards for improving work processes and team morale

GE CONSUMER FINANCE **2001-2006**

Customer Service Call Center Manager

Responsible for the leadership, development and training of a team consisting of 22 customer service representatives.

Key Achievements

- Led various Six Sigma projects, which resulted in significant process improvements. One in specific was the reduction in credit card dispute errors by 50%.
- Increased team productivity by 30%, which resulted in FTE cost savings of 100k annually.
- Led the call center in the transformation from service to sales resulting in a smooth cultural shift from a service only to a service and sales environment
- Increased sales rate by 50% by implementing recognition programs that focused on recognizing individuals driving the business metrics and goals
- Recognized among 2000+ individuals companywide for leading the efforts of transforming the call center into a sales and service organization
- Through effective recruiting, development and motivation strategies, improved employee attrition by 40%.
- Part of the team responsible for the creation and implementation of a Business Continuity Plan.
- Developed and implemented a scorecard tool to improve performance management and coaching
- Selected by upper management team to help with the startup of a new call center in Monterrey, Mexico, which resulted in a smooth and seamless startup

EDUCATION

- Executive MBA - University of New Mexico
- Bachelor of Business Management, University of Phoenix
- Energy Executive Course- University of Idaho

TRAINING & DEVELOPMENT

- Six Sigma – Green Belt Certification
- Oz Principle
- Lead Culture
- Foundations of GE Leadership
- Building Essential Leadership Skills
- Managing Skills for Leaders
- Increasing Human Effectiveness
- Coaching for Premier Performance
- Executive Credit Union Certification
- Phone Pro- Customer Service Pro Training
- Phone Pro- Coach the Coach Training

COMMUNITY

- Hispano Philanthropic (UWCNM) Society Council Member
- Sandoval Economic Alliance Board Member

GCG#529864

Prepay Trends Analysis & Database Update

Prepay Energy Working Group
July 19, 2022

View Recording

Summary

The Prepay Energy Working Group (PEWG) was created in 2010 to facilitate the sharing of information among utilities interested in prepay programs. We study the business case for offering customers a prepay option, the design of prepay programs, the customer experience, the reasons for high levels of customer satisfaction, conservation impacts, the use of prepay to pay down arrearages, and the operational impacts of prepay. Utilities face different circumstances and are at different stages of prepay program development; therefore, we explore planning issues, barriers to regulatory approval, pilot program design, and the performance of full-scale, long-standing prepay programs.

The PEWG Database

Prepay energy is pay-as-you-go service. There is value in giving consumers choice in service payment. In the 1990s, electric cooperatives and public power utilities started offering prepay programs in North America. About eight years ago, investor-owned utilities began to continuously offer full-scale prepay programs. Many highly-successful programs have now reduced customer debt and improved customer satisfaction. Since 2015, the PEWG database has tracked prepay program features and trends to help to better understand the best practices and drivers of success. Today we highlight the findings of the eleventh update to the PWEG database.

Agenda or Table of Contents

Why Prepay Energy?

Its features and the target segments

What is Prepay Energy?

Prepay energy is a voluntary bill pay option for consumers to pay ahead for energy consumption in the future. Some consumers appreciate the convenience and flexibility of the option. Others appreciate an alternative to security deposits or payment arrangements.

Once consumers begin using prepay energy, they tend to drop their energy consumption significantly.

What are Some Features of Prepay? ("12 C's")

Prepay service is a daily transaction that eliminates utility bills. Rather than paying a bill after usage, consumers maintain a prepay account, learn the cost of one day or one week of service, learn how to maintain service, and learn how to pay off any arrearage.

Feature	Using the feature in other services
Convenience	"Convenience" is the most frequently cited value of prepay; prepay is flexible, simple, and suits many lifestyles
Commitment	Making a commitment to pay in advance empowers those who have responsibility to manage household expenses
Choice	Choice—even between two things—gives consumers agency; households choose when and how much to pay
Conservation	Accurate, timely information teaches people about cost drivers, adjust behaviors, exercise thrift, and save 10%
Control	Paying in advance avoids a security deposit; unbanked consumers want a place to bank dollars; "knowledge is control"
Communication	Simple, frequent communications are preferred; daily cost information satisfies curiosity about household cost drivers
Clarity	Advanced payment is simple; prepay eliminates surprise bills; daily billing is understandable; traditional bills are dense
Customization	When, how, and what information is received is are controlled by consumers; info & payments match lifestyle
Currency	Routine payments to the account align with consumer's value of the service; consumers embrace the value of service
Commodity	Almost no one understands a kilowatt-hour of the commodity; prepay transactions transcend commodity billing
Collections	People work off debt in direct proportion to payments (% of payment is applied; no fixed monthly payments)
Connection	Prepayment realigns the customer-utility relationship; customer expectations match reality; trust in the utility grows

Who Loves Prepay? (five persona / segments)

Recent Immigrants
- All income level
- Experienced with prepay
- Provides control and convenience
- May be paid in cash

Millennials and Gen Z
- Pay-as-you-go is appealing
- Ease of payment is important
- Provides cash management
- They do everything on their phone

Wealthy
- Top 10% of income
- Children in college
- Rental properties
- Remote asset management
- Automatically reload

Low-Income or Struggling Households
- Alternative to security deposit
- Paid weekly; cash management; budgeting
- No savings accounts; prepay enables setting money aside
- In debt; prepay is an alternative to payment arrangement
- Prepay avoids fees and penalties

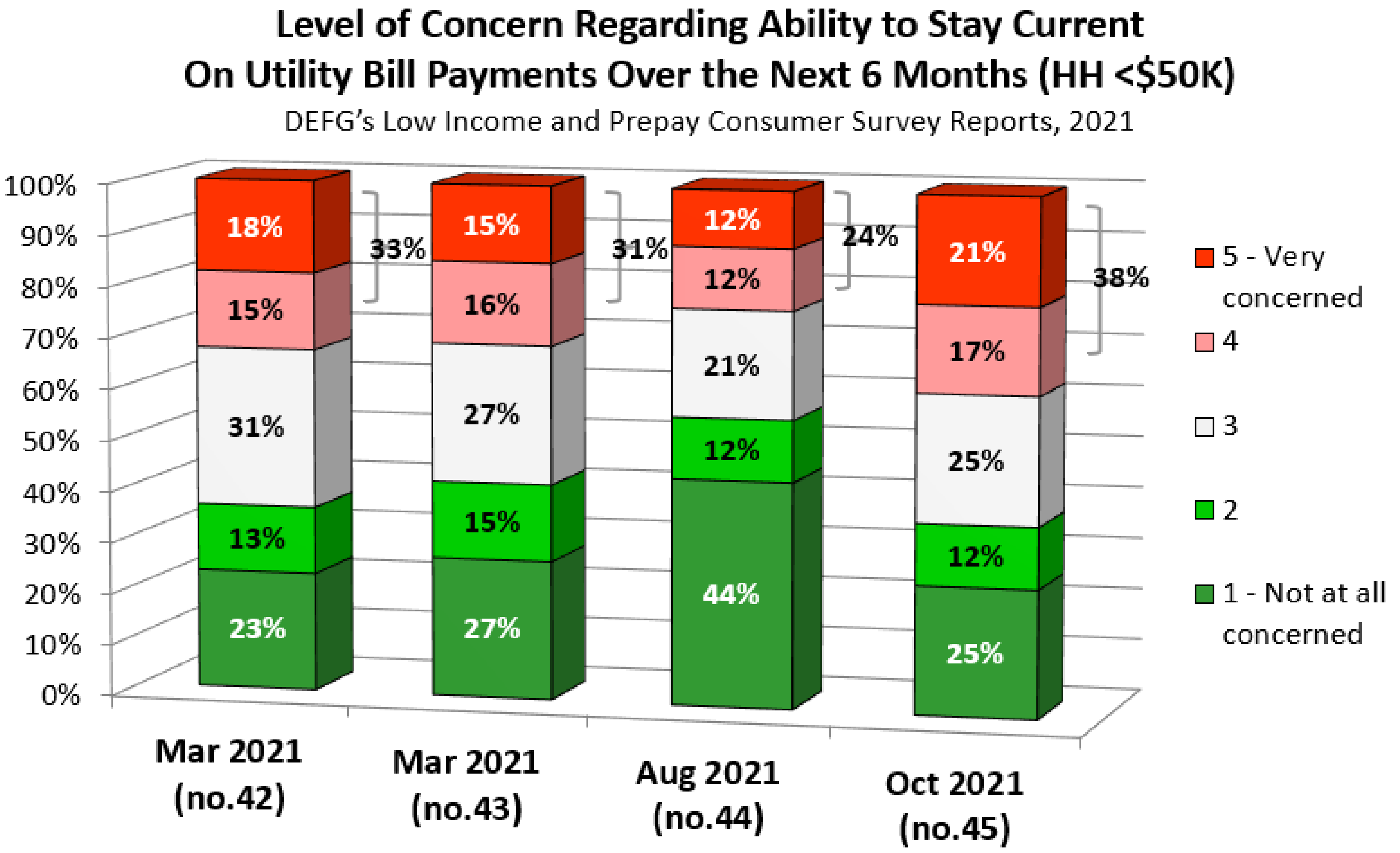
Green / Environmentalist
- Daily information leads to conservation
- Combine with renewable energy
- Precisely know the emissions impacts

U.S. Prepay Programs – Names and Brands

Black River Electric Coop. Inc	PrePaid
Central Electric Cooperative, Inc.	Prepaid
Clinton Utilities Board (CUB)	FlexPay
Cowlitz Public Utility District	Prepaid
Duke Energy Carolinas (North Carolina)	Prepaid Advantage
Duke Energy Carolinas (South Carolina)	Prepaid Advantage
Georgia Power Company	PrePay and Pay-By-Day
JEA	JEA MyWay
Memphis Light Gas Water	Prepay
NV Energy (Northern Nevada)	FlexPay Program
NV Energy (Southern Nevada)	FlexPay Program
Ocala Electric Utility	Prepaid Program
Oklahoma Electric Cooperative	PrePay
Orlando Utilities Commission	OUC Power Pass
Public Service Company of Oklahoma	Power Pay
Salt River Project (SRP)	M-Power®
Santee Cooper	PAYGE - Pay As You Go Electric
Southwest Tenn. Electric Membership Corp.	FlexPay
Tri-State Electric Membership Corporation	Advance Pay
Truckee Donner PUD	PrePay

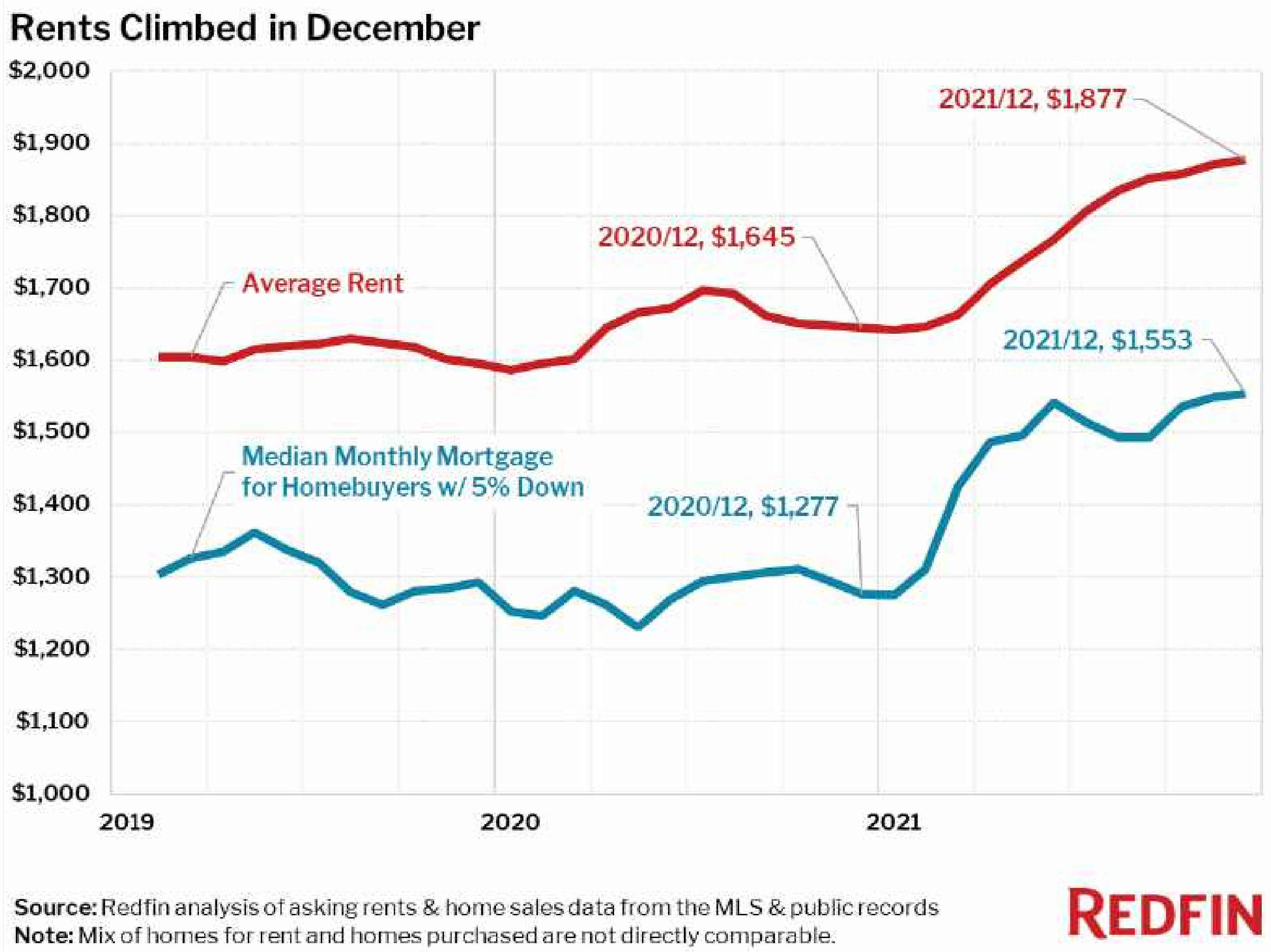
Economic Forces and Consumer Preferences

Consumers are Worried About Utility Bills



How concerned are you about your household's ability to stay current on utility bill payments over the next six months?

Median Rent Rose to $1,877; Mortgage to $1,553



Source: Redfin, Rental Market Tracker: Rents Rise 14% in December, 2022

Three-Year Trend

- Since 2019, median rent has increased 14.1%
- Mortgage has grown 21.6%
- Rising housing costs coupled with inflation will leave low-income households more vulnerable

Utility Customer Base Highly Segmented for Billing and Payment Options

- Utility customers have clear preferences regarding billing options
- More information and control over their ability to pay are key preferences
- When asked to select what is more important between two options:
  - Flexibility over certainty
  - More detail over less detail
  - Incremental payments over larger payments
  - Pay each bill over automatic payments
  - Monthly over weekly
  - Paperless over paper

	Total
Total Respondents	(1018)
	%
Flexibility	55
Certainty	45
Less detail	29
More detail	71
Incremental payments	67
Pay larger amounts	33
Automatic payments	38
Pay each bill	62
Pay weekly	14
Pay monthly	86
Paper	39
Paperless	61

(What Is More Important Regarding Utility Company's Billing and Payment Options) Base: Total Respondents. Q.B15. When you think of your utility's billing and payment options, what is more important to you? Choose one for each response set of comparisons below.

Importance of Offering an Ability to Pay the Electric Bill Using Cell Phone or Mobile Platform

- Clear preference among younger customers for more mobile-friendly payment options
- Investments in mobile payment platforms will pay off as more tech-savvy generations become the dominant customer base

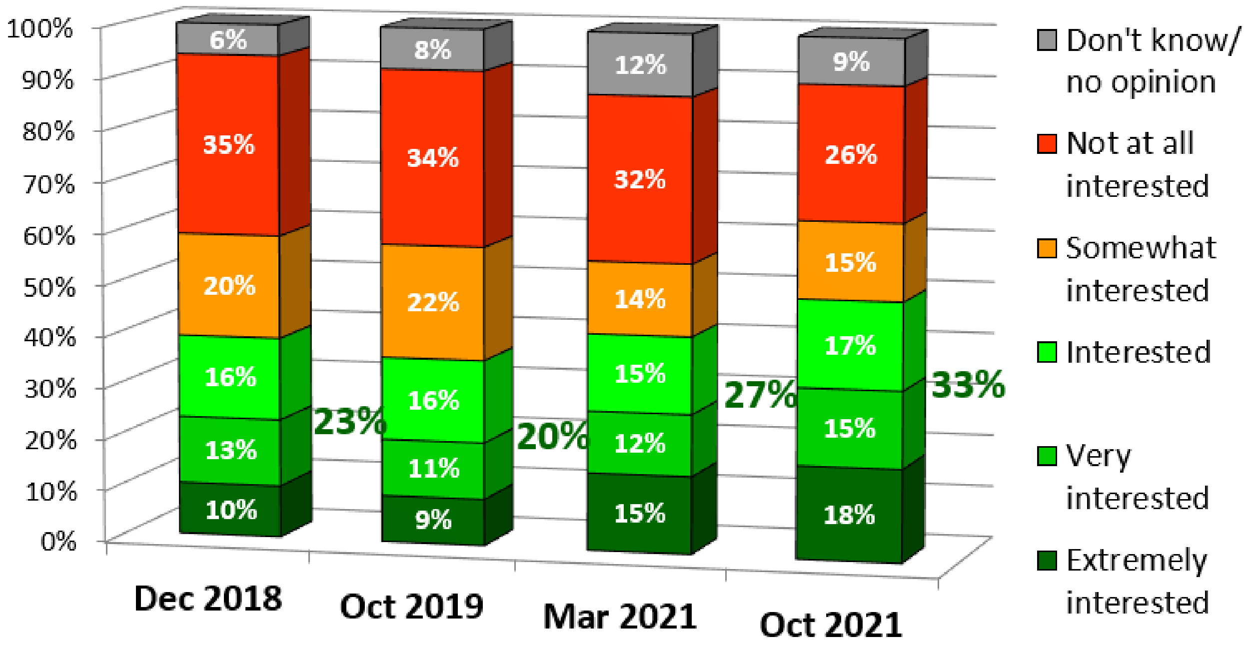
Base: Total Respondents. Q.B16. How important is it to you that your electric utility offer the ability to pay your electric bill using your mobile phone or other mobile platform in the future?

What is Driving Increased Interest in Prepay Energy?

Consumer Interest and Prepay Projections

Interest in Voluntary Prepay Energy from Local Utility

DEFG's Prepay Consumer Survey Reports, 2018-2021



If your local utility or provider were to offer a voluntary prepaid option for consumers, how interested would you be?

Prepay Accounts	# Accts.
Prepay accts. listed in PEWG database	347,000
Estimated number in competitive retail electric market in Texas	200,000
Estimate of others served by electric cooperatives/munis (not in database)	50,000
Continued growth from pilots, expansion of full-scale prepay programs, youthful new customers (next five years)	100,000
Total	**~700,000**

What is Driving Increased Interest in Prepay?

Consumer Debt Has Grown

- During the pandemic, utilities had service disconnection moratoria. Payment requirements were relaxed, and federal assistance increased. Now, as service returns to normal, past-due amounts have grown. Consumers seek alternatives to pay down debt.

Managing Rate Increases and Inflation

- Almost every utility is filing for rate increases; there are fuel-cost adjustments

Younger Consumers Prefer Mobile

- Prepay is easy to understand, easy to manage, and more transparent than traditional post-paid service. Younger consumers are especially interested in mobile transactions.

Flexibility in Arrearage Management is Valued

- Prepay energy is an important tool to manage customer arrears. Consumers work off debt in direct proportion to usage. Thrifty consumers take longer, but progress is steady. (Contrast with fixed-term deferred payment arrangements.)

Summary: Near Term and Going Forward

Near Term

- Consumer debt to utilities is large and growing and the arrearages increased during the pandemic
- Inflation is making matters worse for fixed-income and struggling consumers as well as for young consumers just entering the work force
- Rate increases will lead to challenges around managing affordability

Going Forward

- Commodity prices and infrastructure investments will increase costs
- There is increased investment in mobile transactions and expectations for mobile interactions will continue to rise
- Interest is growing in prepay as an alternative arrearage management tool, an alternative to security deposits, and to control against surprise bills
- There will be renewed focus on energy conservation / energy efficiency programs as hedge against higher energy prices

Summary: Key Questions

For a decade, PEWG members have observed that while "prepay may not be for everyone," it is highly-valued, effective tool for certain customers. We face these key questions:

1. Do the experiences of the pandemic offer insights into which consumers value prepay?
2. What is the role of aggressive, targeted communications about using prepayment to manage arrearages?
3. What are best practices and lessons learned about prepay program design in various circumstances?
4. How do utilities plan to serve Gen Z customers if they do not offer them prepay?
5. Will industry decision makers accept that "utility disconnection for non-payment" is different from "customer self-disconnection to manage a prepay account"?

Prepay Database Highlights

Highlights: Utility Comments & Updates

APS: We must not disconnect customers for non-payment between May 15 and Oct 15. This moratorium presents interesting challenges for prepay. I would be very interested in learning how other companies deal with a moratorium, and on a separate note, what type of prepay rate utilities offer (e.g., flat, any available rate, specialty).

Commonwealth Edison: Still transitioning to a new CIS system. The plan is to revisit the prepay program proposal some time in 2024.

Entergy: Currently live in both Mississippi and Arkansas; approved in Q1 and Q2, respectfully. It's a very slow rollout. Prepay platform is sitting on SAP. No plans with our other three operating companies.

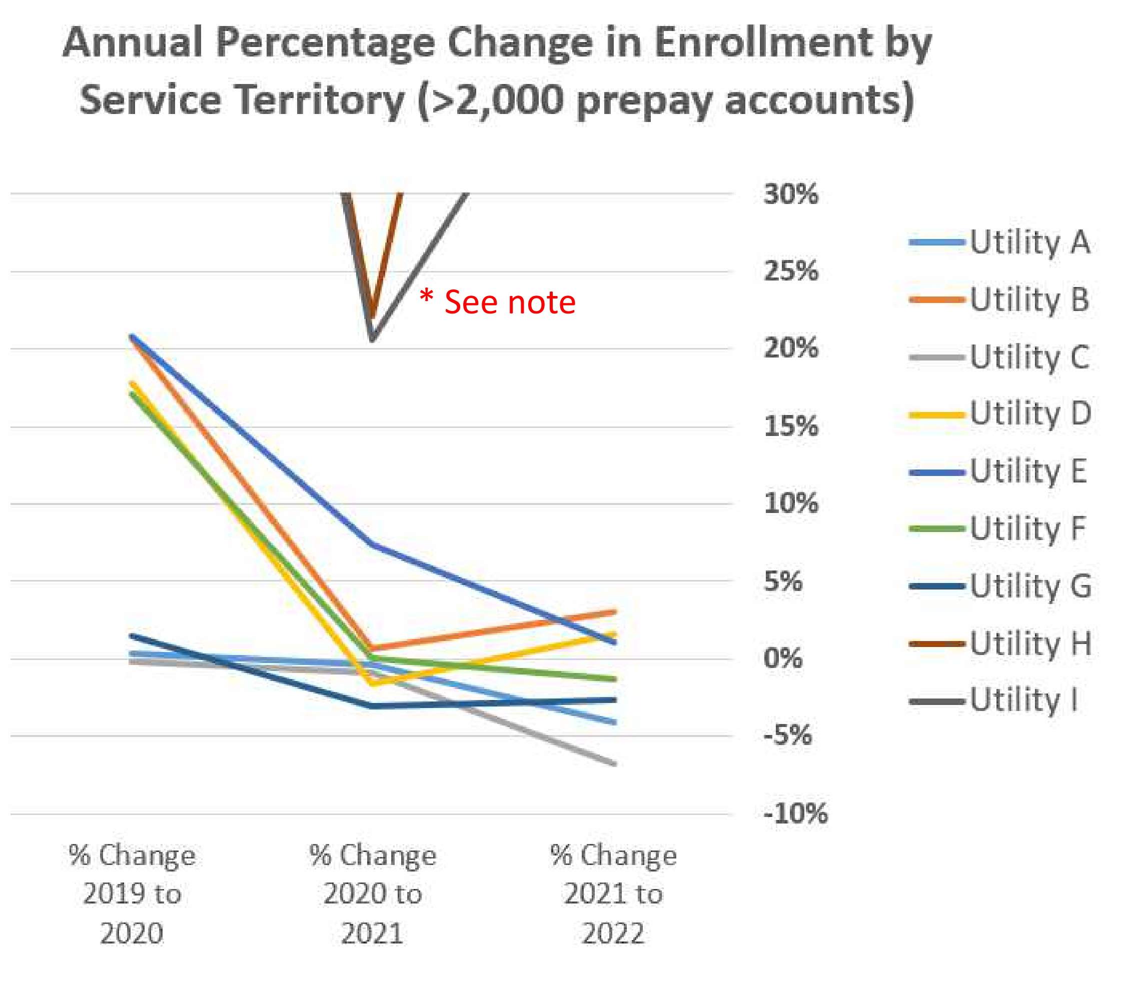
Eversource: We currently do not have a prepay option. We did include this in our plan for our AMI implementation, however, we are still waiting on regulatory approval which may not come until later in 2022.

Georgia Power: Returned to full normal operations in mid-June 2021. Prepay accounts increased 2.7% since return-to-normal and the program is in a steady maintenance state. We are continuing to focus on communication plan: 1) improving customer communications (e.g., notification messaging) and 2) Education to reduce repeat calls.

OG&E: We plan to implement but the process is currently on hold within our IT organization. We should be moving forward this fall/winter. We did a pilot and included in [it in] our Terms and Conditions after the that.

SMUD: We are at the very, very early planning stages and is still working through an initial business case and project charter to seek approval to explore a program further.

Highlights: Year-Over-Year Enrollment Trends



Prepay customer enrollment slowed from 2020 to 2021 (during COVID) across all service territories

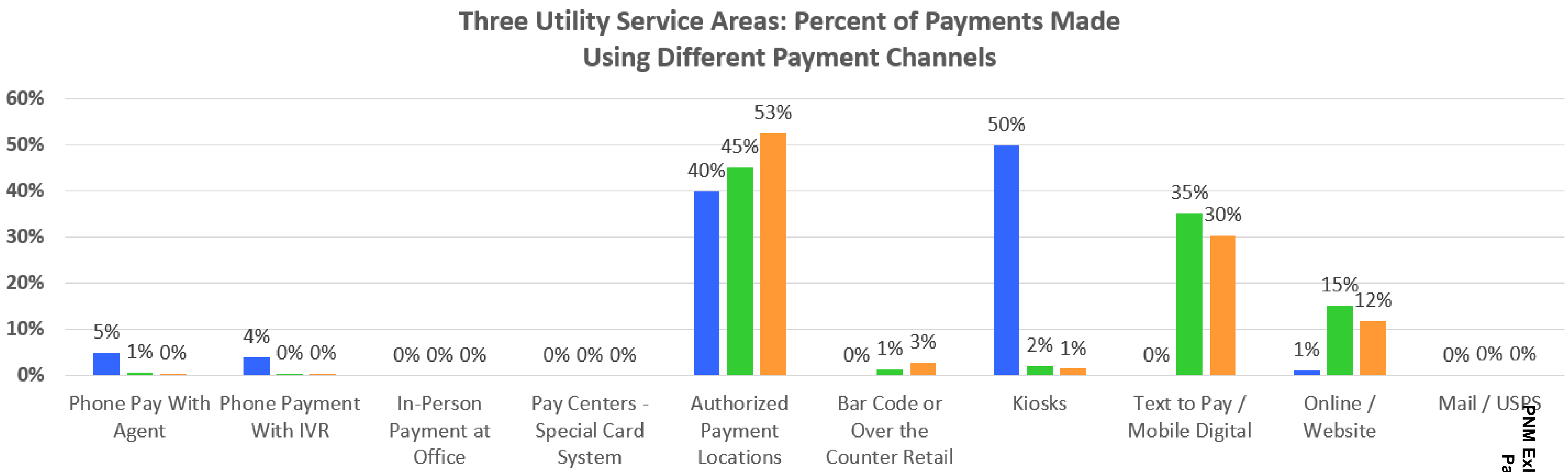
More recently, several service territories continued to slow while others resumed growth

Different program designs underlie these data; that is, program design and regulatory policies matter

* NV Energy North & NV Energy South started from a very low base in 2019 and thus showed a very high growth ("off the charts") from 2019 to 2020, then more modest growth (~20%) from 2020 to 2021, before returning to very high growth during the most recent reporting year

This year we expanded the database to track prepay enrollment over several years

Highlights: Payments Channel Data



This year we replaced "Do you offer this payment channel? [Yes/No]" with "What percent of payments occur in each channel?"

PEWG Database Update

Structure of the PEWG Database

CATEGORIES:

- Utility Contact Information
- General Program Features
- Eligibility
- Pilot
- Operations
- Enrollment
- Marketing
- Account Management
- Zero Account Balance Rules
- Pricing and Tariffs
- Fees and Charges
- Arrearages and Debt Recovery
- Disconnection
- Payment Process
- Impact Assessment
- Business Case Metrics
- Call Center
- Business - Other

IOUs	Public Power	Cooperatives
Ameren Illinois	Almeda Municipal Power	Black River Electric Coop. Inc
Ameren Missouri	Austin Energy	Central Electric Cooperative, Inc.
Arizona Public Service	BC Hydro	Connexus Energy
Avista	Clinton Utilities Board	CoServ
Baltimore Gas & Electric	Cowlitz PUD	Oklahoma Electric Cooperative
Commonwealth Edison	CPS Energy	Southwest Tenn. Electric Mem. Corp.
Consumers Energy	JEA	Tri-State Electric Membership Corp.
DTE Energy	Memphis Light Gas Water	
Duke Energy (three service territories)	Ocala Electric Utility	
Entergy Services (three service territories)	Orlando Utilities Commission	
Evergy	Salt River Project (SRP)	
Eversource	Santee Cooper	
Georgia Power Company	SMUD	
Minnesota Power	Truckee Donner PUD	
NV Energy (two service territories)		
OG&E		
Pacific Gas and Electric Company		
PECO		
PHI - Delmarva Power		
PSEG Long Island		
Public Service Co. of Oklahoma (AEP)		
Tampa Electric (TECO)		
Tucson Electric Power		
Wisconsin Public Service/We Energies		

40+ Utility Service Territories Are Monitored

Who is Eligible?

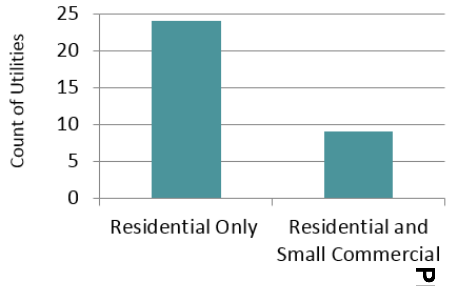
Full Scale Residential and Small Commercial

- Central Electric Cooperative, Inc.
- Clinton Utilities Board (CUB)
- Cowlitz Public Utility District
- Oklahoma Electric Cooperative
- Public Service Company of Oklahoma
- Salt River Project (SRP)
- Southwest Tenn. Electric Membership Corp.
- Tri-State Electric Membership Corporation

Full Scale Residential Only

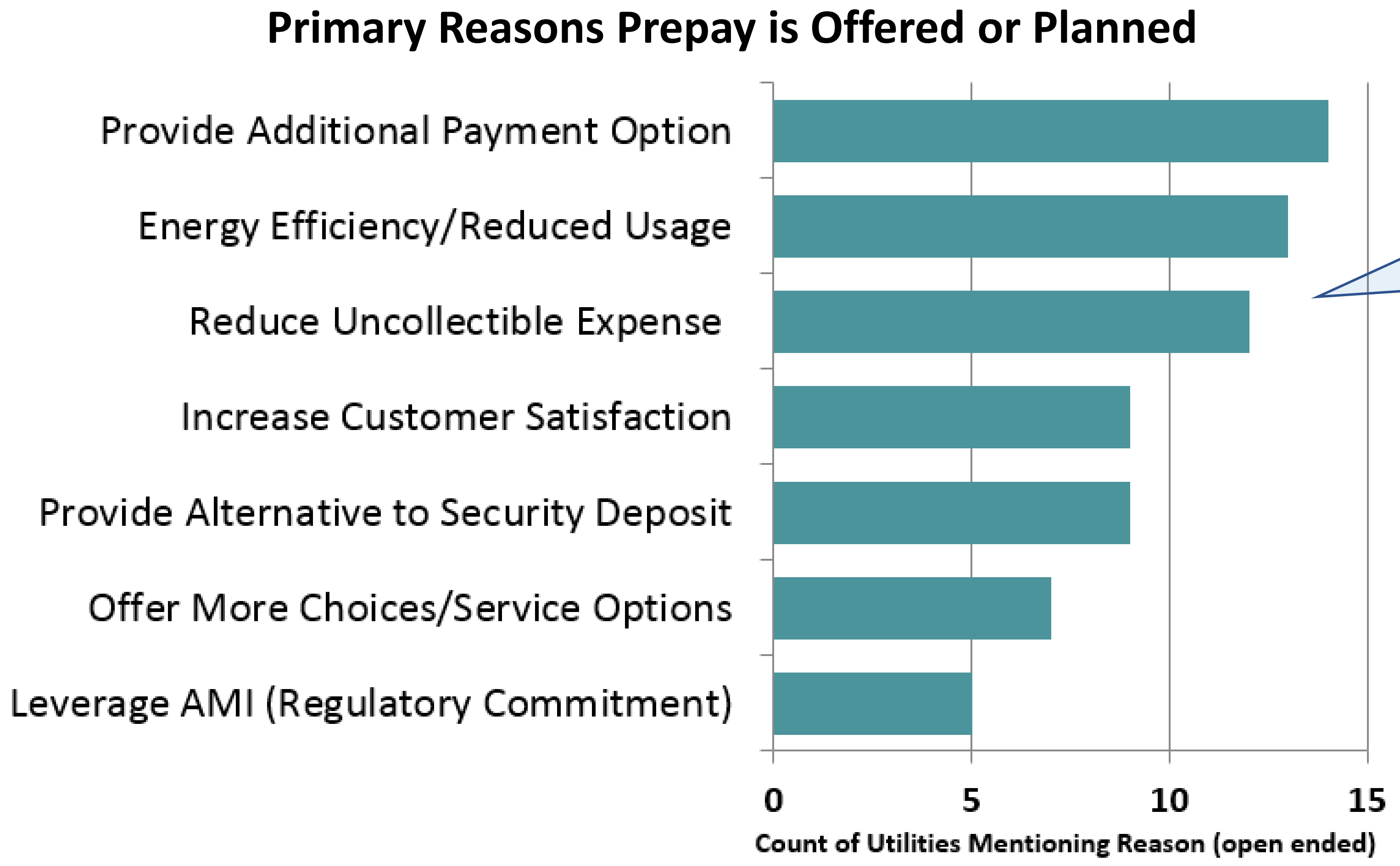
- Black River Electric Coop. Inc
- Georgia Power Company
- JEA
- Memphis Light Gas Water
- NV Energy
- Orlando Utilities Commission
- Santee Cooper
- Truckee Donner PUD

Full Scale, Pilot, and Planned Prepay Programs



Primary Reasons to Offer Prepay

Prepay addresses many business objectives (hybrid business case)



No utility offered an update to its primary reasons for offering prepay; however, there is increasing use of prepay to address arrearages

Number of Prepay Accounts	
Salt River Project (SRP)	153,000
Georgia Power Company	84,500
JEA	23,200
NV Energy (Southern Nevada)	17,845
Public Service Company of Oklahoma	12,600
Orlando Utilities Commission	10,500
Southwest Tenn. Electric Membership Corp.	8,000
Oklahoma Electric Cooperative	7,654
Ocala Electric Utility	6,850
Santee Cooper	4,295
Memphis Light Gas Water	4,189
NV Energy (Northern Nevada)	4,044
Duke Energy Carolinas (South Carolina)	2,400
Clinton Utilities Board (CUB)	2,343
Black River Electric Coop. Inc	2,200
Cowlitz Public Utility District	1,777
Tri-State Electric Membership Corporation	1,400
Central Electric Cooperative, Inc.	144
Entergy Arkansas	46
Entergy Mississippi	29
Truckee Donner PUD	20
Duke Energy Carolinas (North Carolina)	20

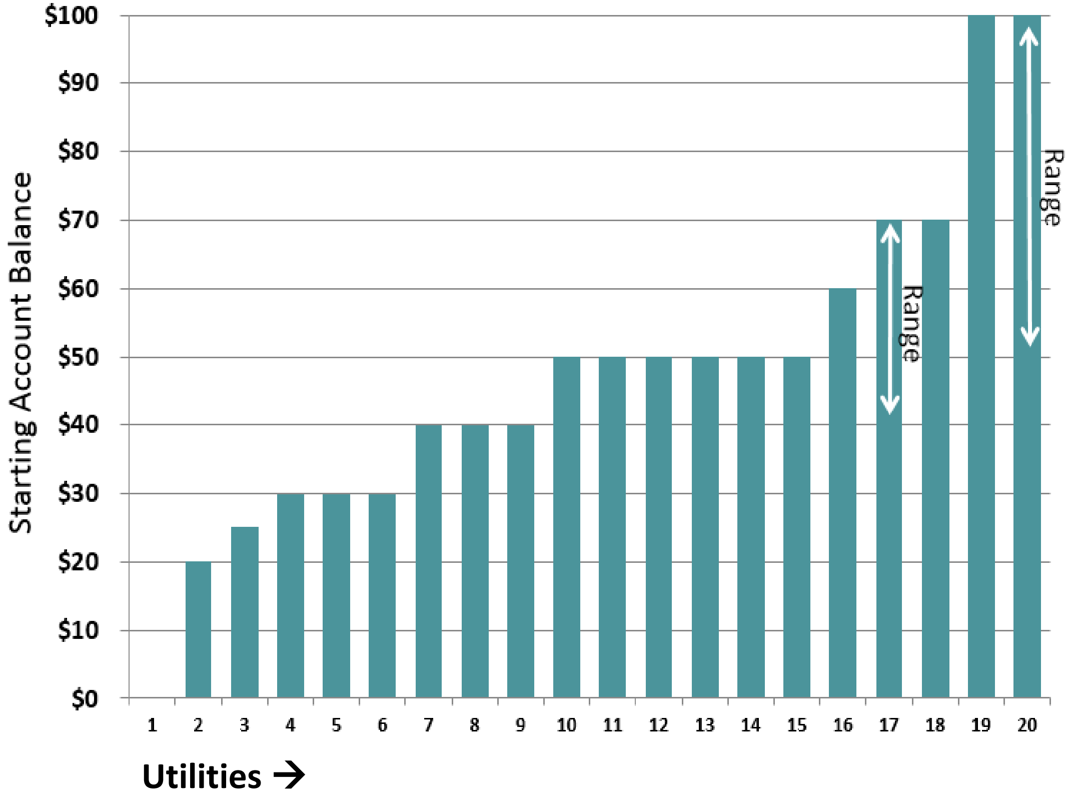
347,000 prepay accounts are reported in the database

Current and Projected Market Penetrations

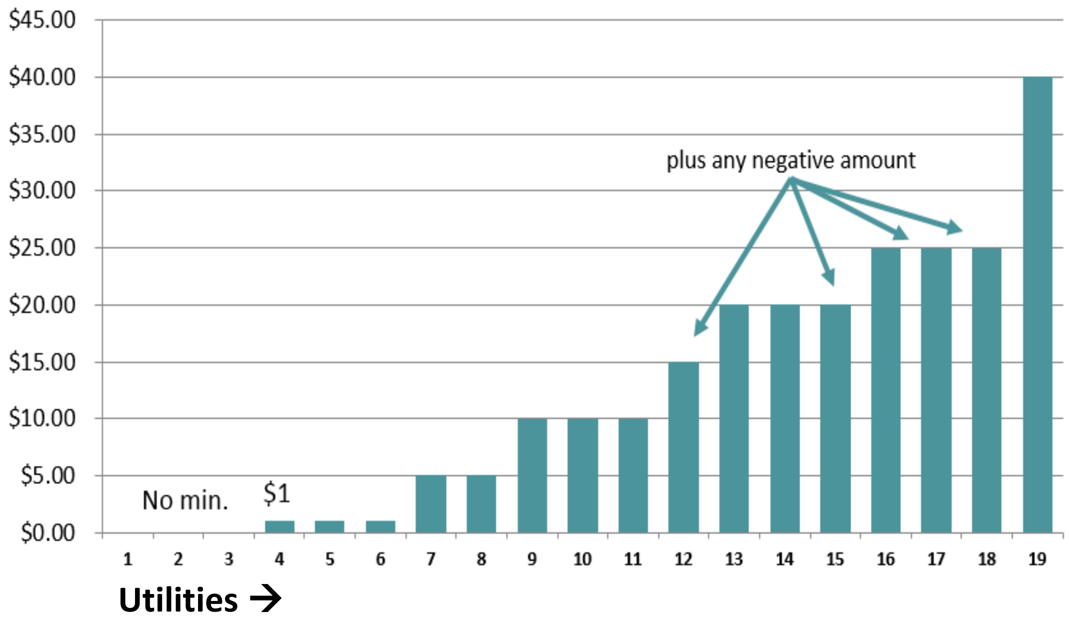
	Current	Projected
Southwest Tenn. Electric Membership Corp.	19.0%	20%
Salt River Project	15.3%	18%
Oklahoma Electric Cooperative	14.0%	17%
Clinton Utilities Board	9.6%	12%
Tri-State Electric Membership Corporation	8.8%	11%
JEA	6.6%	7%
Black River Electric Coop. Inc	6.0%	8%
Santee Cooper	2.5%	5%
Public Service Company of Oklahoma	2.0%	10%
Memphis Light Gas Water	1.0%	5%
Entergy Services	--	5-10%
Consumers Energy	--	10%
Cowlitz PUD	--	5%
NV Energy	--	3.5%
Baltimore Gas & Electric	--	3.5%
Central Electric Cooperative	--	3%

Minimum Starting Balances and Required Payments

Minimum Required Starting Balance

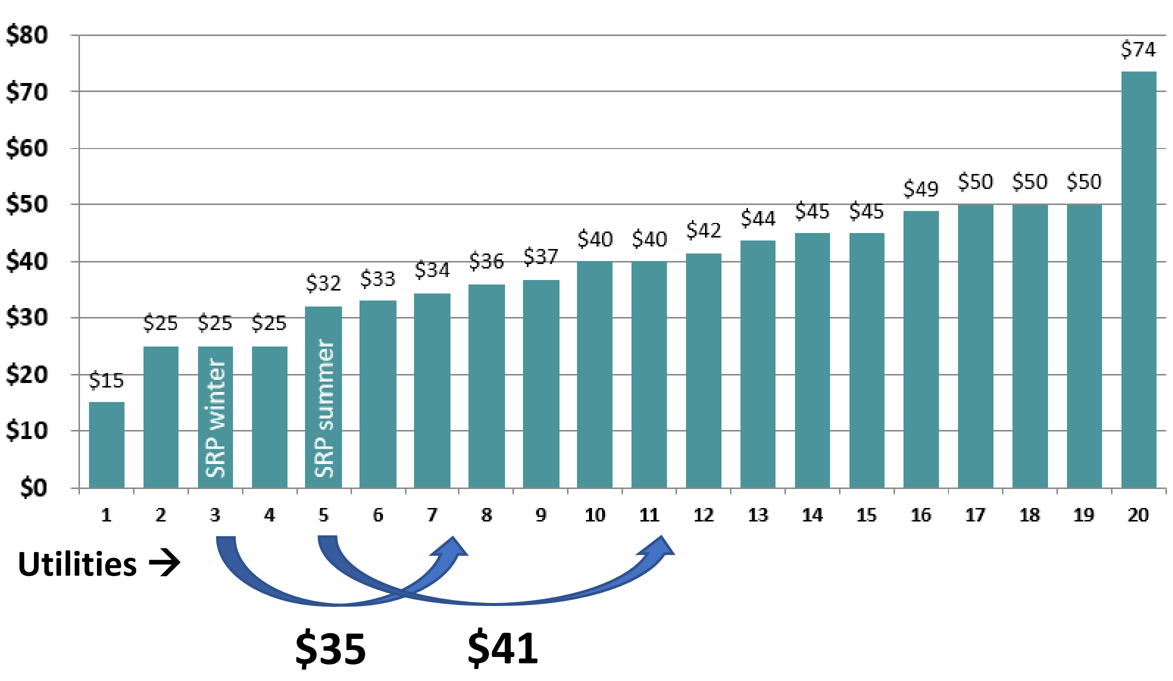


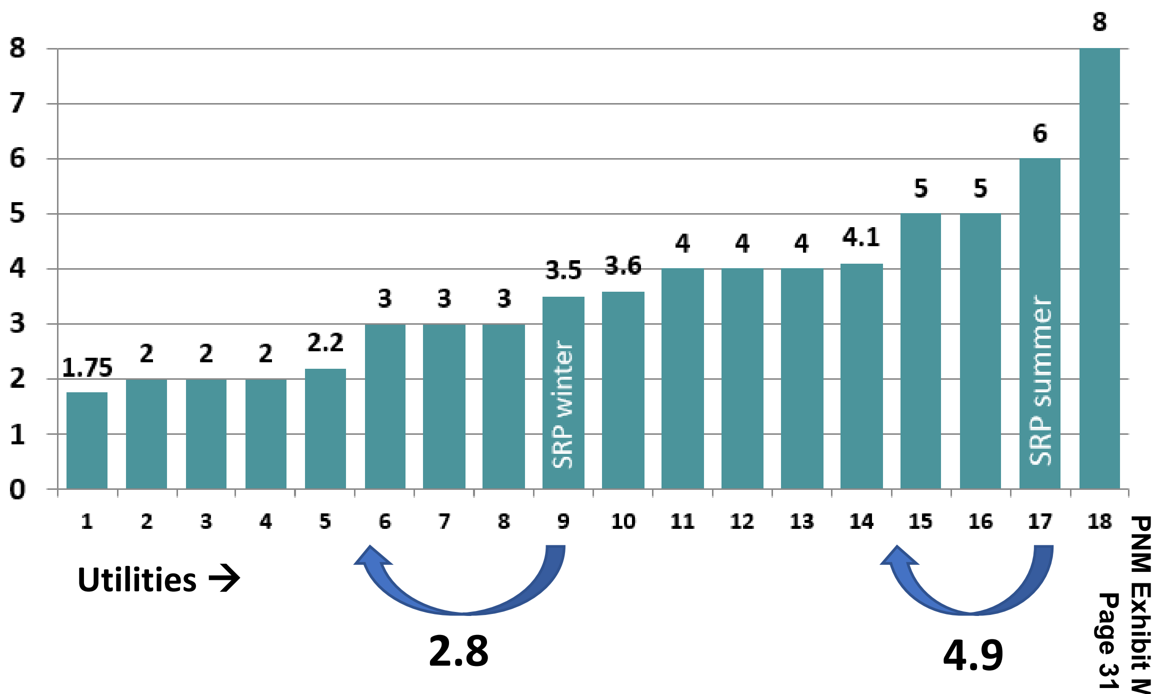
Minimum Normal Required Payment



Based on reported data from full scale and pilot programs, a typical minimum starting account balance is $50

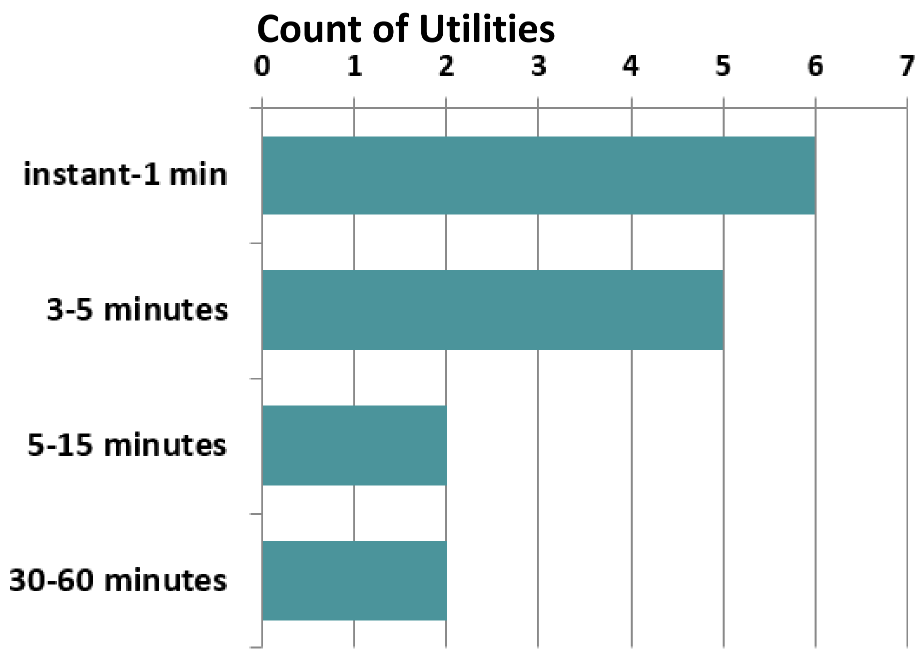
Average Payments and Frequency of Payment



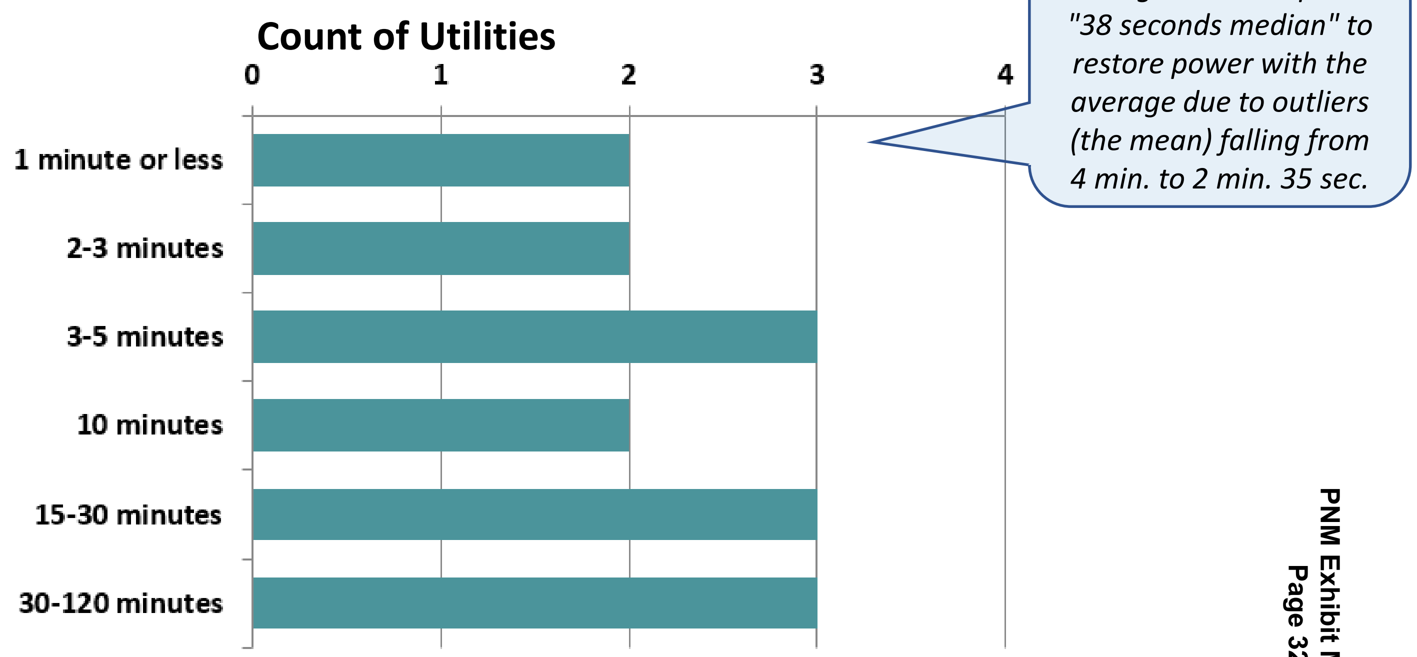


Average Credit Post and Average Reconnection Times

Average Credit Post Time



Average Reconnection Time When Account Balance is Restored



Trends are downward as technology improves

Split Applied to Any Dollar Added to a Prepay Account: Available for Current Usage % / Applied to Arrearages %

This includes full-scale offerings, pilot programs, and those close to implementation

50/50	65/35	70/30	75/25	80/20	85/15
Oklahoma Elec. Coop.	JEA (note 1)	Clinton Utilities Board	Cowlitz PUD (note 3)	Public Serv. Co. of OK	NV Energy
	SRP (note 2)	Tri-State Elec. Mbr. Corp.	Duke Energy (note 4)		
			Entergy (note 5)		
			Georgia Power		
			MLGW		
			NV Energy		
			Santee Cooper		
			Tucson Elec.		

Note 1: JEA reported a change in the allocation from 2020 to 2021. It had been 75/25.
Note 2: SRP customers have high use in summer and low use in winter. Winter contributions to arrearages are small. SRP changes 65/35 depending on the amount owed and other factors. The paydown percentage is higher for accounts owing $500 or more.
Note 3: Cowlitz Public Utility District changed a split based on season (60/40 summer; 75/25 winter) to 75/25 year-round (for now).
Note 4: Duke Energy revised this from 60/40 to 75/25.
Note 5: Clarification needed. This is a planning number for Entergy New Orleans.

Findings and Recommendations

- Customer interest in prepay is quickly growing
- More utilities are responding with planning and regulatory actions to stand up a program
- The pandemic had a dampening impact due to no disconnects and little outreach
- Enrollment is starting to pick up again
- Younger consumers expect convenient mobile payment options
- The rational for offering prepay is increasing around bill pay and arrearage management
- Consumer debt is growing, inflation is expected to increase customer arrears, and clean energy investments are likely to increase rates
- Prepay energy is an important tool to manage customer arrears. Consumers work off debt in direct proportion to usage. Thrifty consumers take longer, but progress is steady. (Contrast with fixed-term deferred payment arrangements.)

Next Steps

You will receive this presentation and access to the recording. We will send the database in two formats: (1) an interactive spreadsheet (internal use only) and (2) a redacted PDF (protected and hiding all company names and locations – to be used in regulatory proceedings or with the public).

Upcoming events:

- Thurs., July 21: **"Chief Customer Officer Panel on Managing Affordability"** Three CCOs will discuss strategic perspectives on managing affordability in the utility sector as well as initiatives to help customers. Panelists: Melissa Washington, ComEd; Jared Lawrence, Eversource; Mike Stohl, Citizens Energy.
- Thurs & Fri. Aug. 25-26: **"Working Together for an Equitable Energy Future: National Workshop on Equity in a Clean Energy Economy"** A workshop of the Equity in a Clean Energy Economy (ECEE) Collaborative (https://www.eceecollaborative.com/).
- Thurs. & Fri., October 6-7, noon to noon: **"Annual Meeting of the Prepay Energy Working Group"** Tampa, Florida, hosted by TECO Energy.

DEFG
Customer Insights & Advisory Firm

Contacts

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Nat Treadway
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DEFG is a customer insights and advisory firm in the utility space. Through collaborative research, data analysis and peer-to-peer networking, we help our clients achieve ways to better serve their customers.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	))))))))	**Case No. 22-00058-UT**

SELF AFFIRMATION

MARIO A. CERVANTES, Director, Customer Experience, for Public Service Company of New Mexico, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing **Direct Testimony of Mario A. Cervantes** and it is true and accurate based on my own personal knowledge and belief.

Dated this 3rd day of October, 2022.

/s/ Mario A. Cervantes_____
MARIO A. CERVANTES

GCG # 529845

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	**))))))))**	**Case No. 22-00058-UT**

DIRECT TESTIMONY

OF

OMNI B. WARNER

October 3, 2022

NMPRC CASE NO. 22-00058-UT
INDEX TO THE DIRECT TESTIMONY OF
OMNI WARNER

WITNESS FOR

PUBLIC SERVICE COMPANY OF NEW MEXICO

PNM Exhibit OBW-1	Resume
PNM Exhibit OBW-2	Distribution Technology Roadmap
PNM Exhibit OBW-3	Estimated Distribution Grid Mod Costs

Self-Verification

**DIRECT TESTIMONY
OF OMNI B. WARNER
NMPRC CASE NO. 22-00058-UT**

I. INTRODUCTION AND PURPOSE

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

A. My name is Omni Warner. I am the Director of Distribution Engineering for Public Service Company of New Mexico ("PNM" or "Company"). My business address is 4201 Edith Blvd NE, Albuquerque, NM 87107.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. Please see PNM Exhibit OBW-1 for my educational background and professional qualifications.

Q. PLEASE DESCRIBE YOUR ROLE AS DIRECTOR OF DISTRIBUTION ENGINEERING.

A. In my role, I am primarily responsible for Distribution Engineering services, which includes Distribution Planning, New Service Delivery, Distribution standards, and distribution upgrades and replacements. My team supports the design and development of the grid modernization technologies on the PNM distribution system.

Q. HOW ARE YOU QUALIFIED TO OFFER THIS TESTIMONY?

A. My educational background in electrical engineering, including a BSEE and MSEE in power systems, provided the technical foundation for the fundamental understanding of the electrical grid design, operations, and engineering. My career started in generation where I had responsibility for all components of the electrical system at large power generation facilities. In these responsibilities I managed the maintenance, operational and engineering practices for all aspects of the power system in a condensed and tightly coordinated system with a very specific focus of delivering energy to the grid. The diversity of my experience prepared me for the same coordination of generation resources integrating with the distribution system that is developing in the PNM's distribution system today.

Q. WHY IS GRID MODERNIZATION A CRUCIAL NEXT STEP FOR PNM AND WHY IS IT NEEDED NOW?

A. A central objective for PNM in undertaking grid modernization efforts is to drive toward a carbon-free transition by 2040, ahead of New Mexico's energy transition policies.[1] Grid modernization is crucial to achieving this transition to carbon-free and will ensure that power remains reliable, resilient, and secure even as PNM

[1] PNM is required to supply one hundred percent of all retail sales of electricity in New Mexico from zero carbon resources by January 1, 2045. NMSA 1978, § 62-16-4(A)(6) (2019). By January 1, 2040, no less than 80 percent of all retail sales of electricity in New Mexico are to be supplied through renewable energy resources. *See* Section 62-16-4(A)(5). PNM has made a commitment to reaching this 100% goal by 2040.

drives toward its carbon-free goal. In particular, grid modernization supports enhanced integration of carbon-free resources, providing a means for PNM to more efficiently interconnect, optimize and manage the use of distributed energy resources ("DERs").

PNM's distribution system is aging. Based on stakeholder engagement in advance of this filing, PNM knows that customers want a reliable grid with minimal power outages and shorter outage durations, as well as the ability to quickly interconnect customer-owned distributed generation. To deliver service enhancements like reliability and resilience and to meet customer expectations for DER deployment, PNM requires additional information systems, operational awareness, power management control systems, remote operational control, and automation. These capabilities, coupled with PNM's traditional capital investments in the grid, reduce outages and restore power faster with new sensors and automation, as well as enable the planning and engineering tools to safely integrate a maximum quantity of distributed resources into the power system consistent with the New Mexico's Grid Modernization Statute ("Grid Mod Statute").[2] The upgrades also will enhance PNM's ability to protect against and recover more quickly from power outages due to extreme weather events. The planned grid modernization projects in this case

[2] NMSA 1978, § 62-8-13(B)(1), (3) (2020).

coupled with the traditional capital investments in the grid will transform the Company's aging distribution system into a more transparent, advanced, digitalized and flexible system commensurate with customer needs and expectations of today and into the future. The fact remains that in addition to grid modernization, PNM also needs to invest in feeder rebuilding and other traditional infrastructure investments to accomplish the intended benefits PNM is seeking through grid modernization.

Q. PLEASE STATE THE RESULTING BENEFITS FROM PNM'S PROPOSED DISTRIBUTION SYSTEM UPGRADES.

A. The specific objectives of PNM's plan to modernize its distribution system are discussed below, with reference to the specific section of the Grid Mod Statute that the benefit supports.

- DER Adoption – Enable greater customer adoption of onsite clean energy resources and demand management devices and systems using fast-tracked interconnection processes enabled via robust hosting capacity analyses. Grid Mod Statute, Section 62-8-13(B)(3).
- Reliability – Enhance distribution system reliability through improved prevention, mitigation, and restoration of electric service outages to customers. Grid Mod Statute, Section 62-8-13(B)(1).
- Resilience – Enhance system resilience to protect against, mitigate and recover from high-impact natural disasters and cyber-terrorism threats and risks,

thereby limiting or reducing outages and grid damage. Grid Mod Statute, Section 62-8-13(B)(3).

- Decarbonization – Support achievement of customers' environmental interests, and both state and PNM environmental policy goals by enabling electrification and integrating independent clean energy resources (*e.g.*, community solar and storage) on the distribution grid. Grid Mod Statute, Section 62-8-13(B)(1), (3) and (4).
- Safety, Quality & Efficiency – Ensure service safety and power quality meets performance standards (*e.g.*, service voltage, power factor and power harmonics), and maximize the efficiency and utilization of grid assets. Grid Mod Statute, Section 62-8-13(B)(1), (3).
- Cost-Effective Deployment – PNM's timing for investment of its distribution modernization projects prioritizes the functionality and technology that will effectuate grid advancements as they are needed, while also taking into consideration costs to customers. Grid Mod Statute, Section 62-8-13(B)(1), (3).

These distribution modernization objectives address customers' distribution-related needs identified in the recent customer surveys discussed in the Direct Testimony of PNM witness Julie Rowey.

Q. WHAT GRID MODERNIZATION TECHNOLOGY IS PNM PROPOSING IN THIS CASE THAT WILL ACCOMPLISH THESE BENEFITS?

A. At a high level, PNM plans to deploy technology and tools that: support more sophisticated forecasting and planning, power flow analysis and complex hosting capacity analysis; automate the distribution system to address failure conditions; and coordinate intelligent field devices and permit real-time management of changing voltage and reactive power. Those tools and technology include distribution planning and engineering tools; distribution automation technology, including intelligent switches, reclosers and smart fuses, and fault current indicators that also provide grid sensing capabilities; integrated Volt-Var management; fault location, isolation and service restoration ("FLISR"); and an advanced distribution management system ("ADMS"). I discuss the deployment plans for these technologies in Section III below. PNM's customers—and the grid more generally—will experience a variety of benefits as a result of integrating this technology into PNM's distribution system, as discussed in more detail in Section IV below.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. My testimony details PNM's Grid Modernization Implementation Plan ("Plan") as it relates to PNM's distribution system.[3] Specifically, my testimony discusses how grid modernization will support PNM's carbon-free transition by 2040. My testimony also discusses the value of PNM's grid modernization Plan, focusing particularly on the value to customers. My testimony emphasizes why PNM requires modernization to its distribution system now.

After discussing the broader value of PNM's grid modernization efforts for its distribution system, I describe in detail PNM's proposed distribution modernization Plan, which includes a discussion of the planned distribution investments in PNM's grid modernization Plan and why those investments are needed.[4] My testimony also explains how PNM's Plan was developed and how the timing for investments was determined.

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[3] PNM's Grid Modernization Implementation Plan ("Plan") is attached to the Direct Testimony of PNM witness Laura Sanchez as PNM Exhibit LES-3. This Implementation Plan identifies the projects PNM proposes as part of its Application to further the goals of the Grid Mod Statute and PNM policy objectives. The Plan provides (1) the purpose and benefits of PNM's proposed grid modernization investments, (2) the proposed timeline for deploying proposed projects; (3) an overview of project costs; and (4) identification of the witnesses sponsoring each project.

[4] As discussed below, PNM worked in consultation with Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") to develop its planned distribution upgrades.

Finally, my testimony describes in detail how PNM's proposed projects included in this filing will provide benefits to customers and the grid as a whole by, for example, enhancing reliability and resilience, supporting decarbonization, and facilitating the deployment of critical changes to how PNM integrates DERs, speeds up interconnection processes, and optimizes grid resources.

II. PNM'S STRATEGIC IMPLEMENTATION PLAN FOR A MODERN DISTRIBUTION GRID

Q. PLEASE DESCRIBE PNM'S CARBON-FREE STRATEGY.

A. To achieve PNM's objective of a carbon-free transition by 2040, it must undertake transformative changes across its energy system while focusing on customer value. Broadly speaking, PNM's goal is to provide sustainable, reliable, resilient, and affordable carbon-free energy to the communities PNM serves, while engaging, educating and empowering customers to best meet their changing energy needs and desires. To meet this carbon-free goal, it is necessary for PNM to consider all aspects of utility operations, including modifying and updating its distribution and transmission systems to enable carbon-free energy delivery. PNM also must add utility-scale carbon-free generation resources and energy storage, promote enhanced integrated planning, pursue regional electricity market opportunities, and advance PNM's pricing structure such that customers have options to participate in rates or programs that will facilitate achievement of PNM's carbon-free goals.

Q. PLEASE DESCRIBE HOW PNM'S DISTRIBUTION MODERNIZATION PLAN ENABLES PNM'S CARBON-FREE OBJECTIVES.

A. A carbon-free transition must include both large, utility-scale resources (>10MW) and distributed generation resources (typically <10MW), along with planned electrification and flexible demand resource management. To accommodate this resource mix that is diversified in terms of the types and numbers of resources, as well as in geographic locations, distribution grids can no longer remain a one-way energy delivery system, as originally designed. In other words, the requirements of a carbon-free transition necessitate a modern, flexible distribution grid architecture that is effectively a multi-directional, network-managed delivery system for supporting utility-scale and distributed renewable generation, as well as storage resources.[5]

As described below, the technology required for an advanced, multi-directional distribution system includes distribution planning and analytical tools, grid management functionality, distribution automation, integrated Volt-Var management, and FLISR. In total, PNM's grid modernization strategy and Implementation Plan, including the specific distribution modernization technology

[5] *See* J. Taft and A. Becker-Dippmann, Grid Architecture, Pacific Northwest National Laboratory, January 2015, *available at* https://gridarchitecture.pnnl.gov/media/white-papers/Grid%20Architecture%20%20-%20DOE%20QER.pdf.

proposed in this filing, provide the foundational investments in the distribution system to achieve a carbon-free transition consistent with New Mexico policies.

Q. WHY DOES PNM'S DISTRIBUTION GRID NEED MODERNIZATION NOW?

A. A principal challenge for today's grid is the lack of detailed, centralized information, monitoring, and remote control of the operating condition of the distribution system feeders and related equipment from the substation to the customer. As PNM experiences steep DER development and electrification adoption increases, there is a pressing need to coordinate and integrate more detailed information from the distribution system to enable planners and operators to assess the changing grid conditions. This includes a range of operational and planning analytics, including hosting capacity availability and customers' power quality.

A second key challenge is the need for a more flexible distribution grid infrastructure to address fundamental system efficiency, reliability, and resilience needs with an increasing dependency on intermittent and variable generation resources, including behind-the-meter solar. A more flexible distribution grid infrastructure also is needed to meet expected demand for electricity due to increased electrification in transportation and buildings.

Pursuing advanced distribution technologies with existing grid operational systems and advanced metering infrastructure (“AMI”) functionality will aid in addressing these challenges. For example, enabling the flexibility of real-time monitoring and switching operations to optimize DERs combined with enhanced operational data as to the load on feeders can increase DER and storage resource deliverability, including reducing the number of solar PV curtailments.

To address these key challenges, PNM is pursuing planning, operational, and physical distribution grid investments integrated with existing grid operational systems (“grid-facing technologies”), proposed AMI functionality, and related information and communications systems. My testimony will address the grid-facing technologies. PNM witness Jonathan Hawkins addresses AMI functionality and related information and communications system upgrades. PNM’s requested approvals in this case for both grid-facing and customer-facing physical assets, as well as digital technology to modernize its grid is consistent with New Mexico’s Grid Mod Statute, which recognizes that a modern grid is built from a combination of physical and digital technology upgrades.[6]

[6] The Grid Mod Statute provides examples of grid modernization “assets, technologies or services” to include advanced metering infrastructure and associated communications networks; intelligent grid devices for real time or near-real time system and asset information; automated control systems for electric transmission and distribution circuits and substations; distribution system hardening projects for circuits and substations designed to reduce service outages or service restoration times; and systems or technologies that enhance or

III. DISTRIBUTION MODERNIZATION PLAN

Q. PLEASE DESCRIBE PNM'S DISTRIBUTION MODERNIZATION STRATEGIC PLAN.

A. PNM translated the policy and customer needs discussed above into an actionable, logical grid modernization Implementation Plan to be deployed over the next 6 years. This Plan integrates the various core customer- and grid-facing technologies into a modern grid platform to enable a carbon-free energy future.

As described in more detail in the Direct Testimony of PNM witness Sanchez, PNM seeks authorization in this application to implement the first phase (years 1-6) of the Implementation Plan. Some projects that are part of PNM's longer term strategic vision are set to be deployed in years 7-11, in part to minimize customer bill impacts and to strategically phase-in investments to provide customer value and operational efficiency.

improve distribution system planning capabilities by the public utility. Section 62-8-13(F)(1), (2), (3), (5), (8).

Q. HOW WAS PNM'S DISTRIBUTION MODERNIZATION 11-YEAR STRATEGY AND 6-YEAR PLAN DEVELOPED?

A. PNM's Plan was developed by utilizing industry best practices and leveraging industry experts. PNM engaged both Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") a prominent consulting engineering firm, and EnerNex and Newport Consulting, leaders on grid modernization planning and implementation, to collaboratively support PNM to address the pressing need to improve planning and operation of the grid for the benefit of customers and communities.

In particular, Burns & McDonnell worked with PNM distribution engineers to identify a systematic approach to distribution modernization consistent with PNM's vision of how its grid should evolve over time until a carbon-free transition is achieved in 2040. Burns & McDonnell's analysis focused on the key benefits that could be achieved by distribution modernization, as well as the key concerns of PNM that need to be addressed by distribution modernization—one of those concerns being that PNM's grid must be able to handle higher levels of DER penetration. With these over-arching benefits and concerns as backdrop, Burns & McDonnell evaluated various distribution automation functions and technology, discussed a preliminary deployment approach, identified hardware necessary for deployment, and evaluated the smart device installation methodologies based on various factors. I attach Burns & McDonnell's prepared PNM Distribution

Technology Roadmap Document as PNM Exhibit OBW-2 ("Distribution Technology Roadmap" or "Roadmap"). The Distribution Technology Roadmap summarizes the analysis conducted in conjunction with PNM's engineers.

EnerNex and Newport Consulting helped guide the strategy of grid modernization for PNM within the context of the Grid Mod Statute. These consultants utilized industry best practices and references, including the U.S. Department of Energy's ("DOE") Modern Distribution Grid project with its Next Generation Distribution System Platform ("DSPx") reference,[7] as well as the U.S. National Institute of Standards and Technology Smart Grid Framework[8] to advise PNM in conducting a current state assessment identifying the components needed to support decarbonization goals. EnerNex's Guide for Grid Modernization Implementation is attached to the Direct Testimony of PNM witness Laura Sanchez as PNM Exhibit LES-2. This Guide addresses PNM's broader strategic vision for grid modernization for the full 11-year period PNM intends to deploy grid modernization projects.

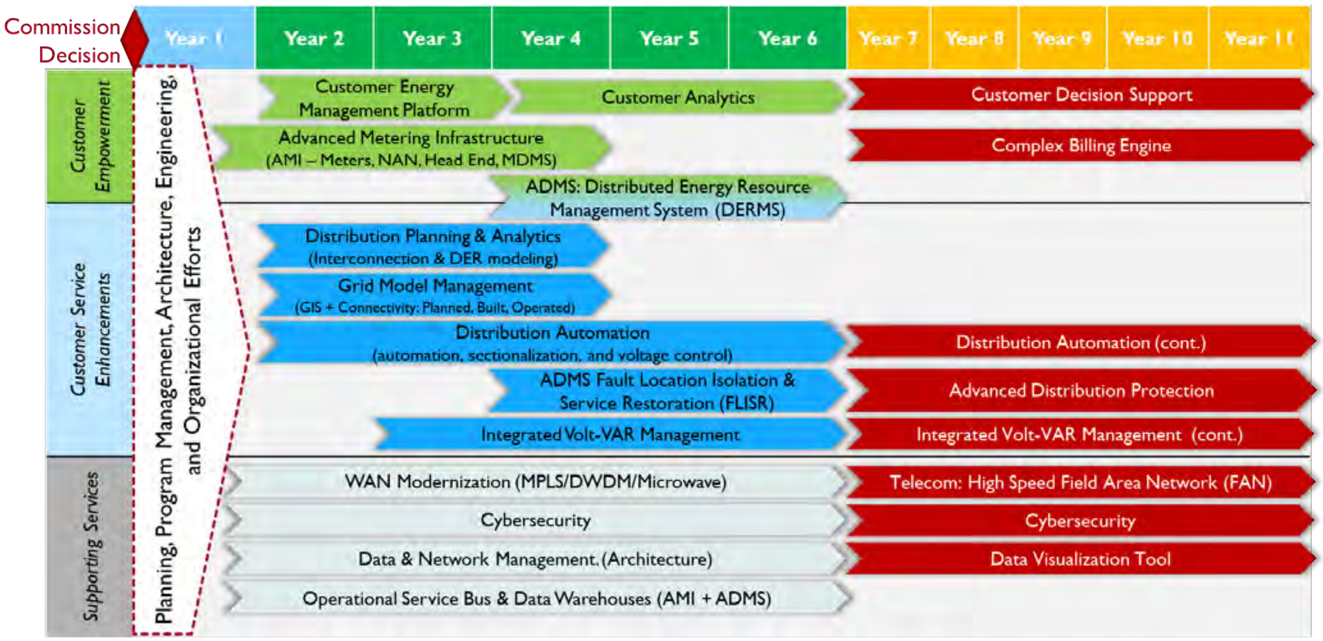
[7] *See* Department of Energy, Modern Distribution Grid Report (DSPx), Volume IV, *available at* https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf.
[8] *See* NIST Smart Grid Framework, *available at* https://www.nist.gov/el/smart-grid/smart-grid-framework.

Using these resources, PNM developed its Plan for grid modernization. *See* PNM Exhibit LES-3, attached to the Direct Testimony of PNM witness Sanchez.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF PNM'S STRATEGIC PLAN AND THE TIMING FOR DEPLOYMENT.

A. The overall strategic grid modernization investment categories and timeline for these investments in PNM's Plan are illustrated below. These projects illustrate the major components and timing of implementation over a 11-year horizon with year 1 including detailed planning, program management and engineering activities following Commission approval of this application. The projects in the initial 6-year Plan lay the foundation for further grid modernization enhancements towards meeting customers' needs and PNM's longer-term, carbon-free transition. The grid-facing technology components identified in blue are in PNM's initial 6-year Plan, and those in red are not part of this application but are part of PNM's longer-term, 11-year strategic deployment for modernization of its distribution grid. As the PNM Figure OBW-1 shows, certain projects, like deployment of distribution automation and integrated Volt-VAR Management Automation, begin in years 1-6, but will continue in years 7-11.

PNM Figure OBW-1[9]



Q. PLEASE DESCRIBE THE SPECIFIC GRID-FACING INVESTMENTS AND THE ESTIMATED COST OF THOSE INVESTMENTS THAT ARE INTEGRAL TO PNM'S GRID MODERNIZATION PLAN.

A. The distribution grid-facing investment categories that are integral to the 6-year Plan are intended to address customer needs and PNM's and New Mexico's carbon-free objectives. My testimony discusses the specific categories of investments in this case, the costs of those investments and the technologies that fall into each category.

[9] This figure also can be found in PNM Exhibit LES-2, which is the Guide from EnerNex.

Distribution Planning and Engineering Tools

These tools support granular load, electric vehicle ("EV"), and DER forecasting as well as power flow analysis for more complex hosting capacity capabilities to maximize the carbon-free resource integration on the distribution system and critical distribution planning functions to reliably develop the architecture for a modernized grid. These planning tools will utilize the significant expansion of grid and customer service data from intelligent field devices and AMI.

The technology included in PNM's distribution planning and engineering category in the Plan includes integration of advanced applications of PNM's existing Synergi distribution planning software, as well as procurement of distribution forecasting software to better forecast DER and load changes based on data from AMI, distribution automation sensors and other inputs. The cost to expand Synergi is based on estimates provided by the vendor as well as estimates for implementation, installation, and training. The cost for the distribution planning software is based on reference pricing for software packages that provide this functionality, as no specific solution has been selected yet.

PNM estimates approximately $1.4 million in capital costs in year 3 and approximately $7.5 million in capital costs in year 4 of the 6-year Plan on these distribution planning and engineering tools. These capital costs include the cost of forecasting tools, additional Synergi modules and interconnection management systems. In addition to the capital clearings, PNM anticipates spending approximately $3.7 million for operations and maintenance ("O&M") costs for distribution planning and engineering of the 6 years of the Plan. Those costs include software licenses and new employee expenses. Further detail for capital and O&M costs are outlined in PNM Exhibit OBW-3.

<u>Distribution Automation</u>

When distribution automation is integrated with PNM's existing and planned operational systems, it will significantly expand the monitoring, coordination, and operation of distribution field components. This will enable automated circuit reconfiguration to address failure conditions on the distribution system, as well as grid operator adjustments in response to changing loads and DERs. These devices also provide grid data for the more sophisticated planning being pursued and will result in more intelligence on the system to allow for continuous operation and optimization of DERs and EV charging both in normal and abnormal system configurations.

Distribution automation includes intelligent switches, including reclosers and smart fuses, fault current indicators, and voltage management components. These devices contain sensors, on-board analytics, microprocessors, and communication interfaces. It is anticipated that it will take at least 11 years to deploy the envisioned number of distribution automation devices, although only the initial 6-year deployment is included in this application. Prior to grid modernization, PNM has deployed a very limited number of these devices to gain some understanding of their capabilities and functions. PNM's Plan will deploy these devices at a much larger scale.[10] The pace of planned deployment for these devices is subject to change based on supply chain and resource availability. As PNM gains more understanding of its pace of deployment, it will update the Commission in the annual Grid Modernization Rider review and reconciliation filings.

PNM estimates capital clearings for distribution automation will be approximately $12 million in year 2, $16.2 million in year 3, $16.6 million in year 4, $17.7 million in year 5, and $17.9 million in year 6. Distribution automation is the most significant grid-facing investment for PNM's 6-year Plan, but the benefits of such automation are similarly significant. I discuss the benefits of distribution automation below. The estimated cost is based on the cost to procure, engineer, install, and integrate these devices into the distribution grid and the Automated Distribution Management System ("ADMS"). In addition to capital clearings, PNM estimates spending $4.7 million in O&M over the 6-year Plan. The O&M spending are for additional employees necessary to deploy and reliably maintain

[10] The Burns & McDonnell Distribution Technology Roadmap discusses recommendations as to the deployment of these devices over an 11-year period, including the value of the deployment and other deployment considerations. For some of the technologies, Burns & McDonnell has provided specific recommendations as to the number of devices that PNM may wish to deploy over the next 11 years. *See, e.g.*, PNM Exhibit OBW-2 at Table 2.

the distribution automation technology. Further detail for capital and O&M costs are outlined in PNM Exhibit OBW-3.

Integrated Volt-Var Management

Integrated Volt-Var management is a holistic approach to allow real-time management of the changing voltage and reactive power dynamics on the grid resulting from solar production and EV charging. PNM's current approach is to gain intelligence through AMI and distribution automation sensors to determine where voltage support is needed. Deployment of substation and distribution automation voltage management devices (*e.g.*, transformer online load tap changers ("OLTC"), substation voltage regulators, substation capacitor banks, line voltage regulators, line shunt capacitors, secondary Var controllers)[11] and operational controls necessary to coordinate with advanced inverters to support the expansion of distributed solar and EV fast charging will provide voltage support. While smart inverters may provide some voltage support for the system, the coordination of these devices is critical to provide reliable service for all customers on a distribution system.

[11] The Burns & McDonnell Distribution Technology Roadmap discusses recommendations for deployment of some of this technology. *See, e.g.*, PNM Exhibit OBW-2 at Sec. 4.2.3 regarding capacitor banks.

PNM has included some of the costs for integrated Volt-Var management in its 6-year Plan. Those costs are included in the distribution automation costs estimated above. The full integration of Volt-Var is expected to start in year 3 and continue through the remaining 8 years of the 11-year plan. However, the Volt-Var investments for years 7-11 are not included in this application for year 1-6 funding. *See* PNM Figure OBW-1.

<u>Fault Location, Isolation and Service Restoration ("FLISR")</u>

FLISR leverages the ability of the distribution automation devices by coordinating operation of intelligent field devices (including intelligent reclosers and smart fuses), operational controls, and supporting communications networks to automatically determine the location of a fault and rapidly reconfigure the flow of electricity so that customer outage times are minimized and the maximum number of customers are restored automatically. The reconfiguring of the system after faults will also help maximize the safe operation of carbon-free resources connected to the distribution system. The cost of FLISR integration is included in the cost of ADMS below.

<u>Advanced Distribution Management System ("ADMS")</u>

PNM's Plan includes the expansion of the ADMS. FLISR deployment requires the implementation of additional ADMS modules, as discussed in more detail below. The ADMS costs in PNM's Plan includes expansion of the existing ACS Prism

Distribution Management System ("DMS") and Outage Management System ("OMS") software modules to include FLISR, integrated Volt-Var control, and Distributed Energy Resource Management System ("DERMS"). The additional module pricing was provided by the vendor, and PNM estimated the cost for the associated implementation, installation, and training.

In this case, PNM estimates capital clearings of approximately $7.6 million in year 4 and approximately $15.4 million in Year 6 of the 6-year Plan on an Automated Distribution Management System ("ADMS") expansion and FLISR integration. In addition to the capital clearings, PNM estimates spending $6.7 million in years 1-6 on O&M spending related to ADMS. Much of this O&M spending relates to software license fees. Further detail for capital and O&M costs are outlined in PNM Exhibit OBW-3.

Q. IS THERE A CONNECTION BETWEEN THE PROJECTS PNM PROPOSES IN THIS CASE TO OTHER EFFORTS PNM IS UNDERTAKING TO SUPPORT ITS GOAL OF A CARBON-FREE TRANSITION BY 2040?

A. Yes. The transition to carbon-free requires a comprehensive commitment on the part of PNM, customers, and regulators. PNM's proposed grid modernization projects are only one component of a multi-layered approach that must be undertaken as part of the carbon-free transition. As such, the grid modernization projects proposed in this Plan will need to be deployed with other projects that PNM proposes or seeks recovery of in future PNM filings. Specifically, grid modernization projects and technologies will foster—or even require—other grid enhancements that may not fit under the rubric of the grid modernization statute. As an example, PNM will propose in its forthcoming rate case various reliability projects related to upgrading its feeders and substations. Such infrastructure investments are crucial for grid modernization deployment in that all grid modernization must be supported by underlying, reliable distribution, substation, and transmission architecture. In other words, the full potential of grid modernization investments is reached by building on top of a robust and reliable base infrastructure built to current day standards.

Grid modernization also could affect future resource planning. When PNM sufficiently deploys the various grid modernization technologies discussed above, the grid intelligence, automation and optimization gained from such technologies is likely to inform the planning and engineering of the grid as PNM determines location, size, and operations of generation and energy storage resources. Grid modernization sensors and technologies will provide data for additional analysis about what resources will be needed and where resources can maximize benefits for the electric grid operation. While it is difficult to predict at this time what drivers might affect the need for additional generation resources,[12] grid modernization will aid PNM in optimizing the use of all resources on its system, decreasing curtailments and increasing operational efficiency, and support a determination of non-wires alternatives to optimize the electric grid planning, engineering design, and operation.

Q. WHAT OPERATIONAL SYSTEMS HAVE PREVIOUSLY BEEN IMPLEMENTED AT PNM ON THE DISTRIBUTION SYSTEM?

A. PNM is at a very early stage of distribution changes to support grid modernization. PNM has begun to implement an ADMS platform from ACS Prism starting with the DMS and OMS software modules. The ADMS is integrated with a Geographical Information System ("GIS"), operational data repository, and a Supervisory Control and Data Acquisition ("SCADA") system for substation breakers and a very limited number of substation load tap changers, field switches and capacitor banks. These prior investments provide some initial functionality to support outage management and operational efficiency. However, there remains considerable gaps on visibility and operational controls that are needed with increased DER penetration and electrification. For example, outages are still primarily reported by customers calling in to the call center or reporting through an

[12] As an example, load growth associated with customers adopting electrification solutions could trigger generation resource requirements even with grid modernization.

online submission. Grid modernization investments in distribution automation sensors as well as AMI will detect outages and provide notifications to the OMS to identify the extent of the outage. The reclosers and smart fuses will then automatically isolate the faulted part of the system to minimize the number of customers affected by an outage. This outage management response will be further enhanced with the ADMS FLISR module.

Q. HOW WAS THE TIMING OF THE DISTRIBUTION GRID-FACING INVESTMENTS DETERMINED?

A. The deployment timing of the components identified in EnerNex's Guide reflects the practical considerations regarding prerequisite activities, equipment lead-times, resource availability, and other relevant implementation considerations, including cost considerations. For example, sufficient deployment of intelligent communicating field switches on feeders in a common geographic area is a prerequisite before implementation of advanced FLISR capability. The other implementation considerations include, for example, the information and communication system development and integration discussed in PNM witness Hawkins' testimony. PNM witness Sanchez discusses the cost-effective deployment of grid modernization projects over the 11-year period.

IV. PNM'S PROPOSED DISTRIBUTION MODERNIZATION PROJECTS PROVIDE CUSTOMER BENEFITS

Q. PLEASE DESCRIBE THE DIRECT CUSTOMER BENEFITS OF THE DISTRIBUTION GRID-FACING INVESTMENTS PNM PROPOSES IN THIS CASE.

A. PNM's distribution grid facing investments create synergistic customer value when aligned with underlying physical grid infrastructure upgrades, including the planned upgrades to PNM's feeders and substations as discussed above. The value proposition of modernizing the distribution grid includes: faster and more efficient integration of DERs and storage; improved load and DER forecasting; robust hosting capacity analysis capabilities that fosters faster and more seamless interconnection; robust EV adoption and integration; improved building electrification; and enhanced grid reliability and resilience. My testimony describes below how the technologies identified in Section III above will accomplish these benefits.

Q. WHAT PLANNED GRID INVESTMENTS ENABLE GREATER DISTRIBUTED GENERATION AND STORAGE INTEGRATION?

A. The existing distribution system is based on engineering design standards associated with the historic role of delivering energy from utility-scale generation resources to the transmission system, and then connecting customers with that electricity through distribution feeders. As distributed generation and storage continue to connect to the distribution grid, it becomes necessary to enhance the distribution system to also enable the gathering and distribution of that energy for the benefit of all customers. As discussed above, PNM's proposed transition to a modern grid architecture will provide greater operational awareness, increased controllability, and switching flexibility, enabled through ADMS capabilities for system operators to obtain sensing and control of substation and distribution automation devices. These capabilities along with physical topology changes enable greater numbers and quantity of distributed resources, both customer and grid connected, to integrate into the power system consistent with the New Mexico's Grid Mod Statute.

As noted above, PNM is at the very early stages of deploying ADMS, providing some initial functionality to support outage management and operational efficiency. However, PNM's deployment of additional ADMS functionality for FLISR as proposed in years four through six of its 6-year grid modernization implementation plan (*see* PNM Figure OBW-1 above) will strengthen PNM's ability to optimize DERs and storage resources on its system.

Q. HOW IS PNM ADDRESSING THE NEED FOR MORE GRANULAR LOAD AND DER FORECASTING WITH THE TECHNOLOGIES IN THIS 6-YEAR PLAN?

A. A prerequisite for more granular load and DER forecasting, including for EVs, is more detailed data on customer consumption patterns—and not just the amounts, but also the shape of consumption (*i.e.*, load profile) and the timing of production and consumption. This is essential as consumption patterns are evolving as customers adopt energy smart devices (*e.g.*, smart thermostats), LED lighting, home automation capabilities, rooftop solar, energy storage, and EVs. Additionally, increasing temperatures and extreme weather events are reshaping seasonal energy consumption. Distributed resources often export energy into the distribution system when the customer's load does not fully consume the energy in real-time. Understanding customer distributed energy exports is critical to understanding customer electricity consumption across the distribution grid. Simply put, historical power flow patterns are changing and becoming more dynamic from a distribution planning and operations view. This is particularly the case at the feeder level where PNM does not have full insight into each customer's production and consumption. Existing SCADA system measurements at the substation effectively dampen the increasingly dynamic customer demand and distributed generation occurring on the circuit and feeder. The combination of interval AMI data, data collected from the intelligent field switches and other devices, and new distribution planning and analytics software to support granular, locational load and DER profiles and forecasting, will substantially improve PNM's understanding of the changes underway to better optimize the design and operation of the electric grid. As noted in PNM Figure OBW-1 above, PNM's 6-year grid modernization implementation Plan includes the deployment of various distribution planning and analytics in years 2 through 4.

Q. HOW ARE THE TECHNOLOGIES IN PNM'S DISTRIBUTION GRID MODERNIZATION PLAN GOING TO ADDRESS THE NEED FOR ADVANCEMENTS IN HOSTING CAPACITY AND INTERCONNECTION STUDY CAPABILITY?

A. PNM is pursuing a phased approach to advance DER interconnection capabilities, including hosting capacity. Specifically, PNM is following industry best practices for a "Walk-Jog-Run"[13] type evolution following the Electric Power Research Institute's ("EPRI") four phases:[14]

- Phase 1: Distribution Indicators – Recognizes specific indicators that contribute to hosting capacity based on available data, but does not represent a complete hosting capacity evaluation.

[13] Gridworks originated the Walk-Jog-Run approach for California's Distribution Resources Plan. *See* https://gridworks.org/initiatives/drp/

[14] EPRI, Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, June 2016. Available online at: http://nyssmartgrid.com/wp-content/uploads/DefiningaRoadmap.pdf

- Phase 2: Hosting Capacity Evaluations – Evaluation of hosting capacity on a feeder-level basis considering the key components of DER impacts.
- Phase 3: Advanced Hosting Capacity Evaluations – Evaluation of the hosting capacity on the more granular (node) level including considerations for operational flexibility and transmission constraints.
- Phase 4: Fully Integrated DER Value Assessments – Hosting capacity assessment combined with DER value assessments that identifies potential benefits including improved efficiency, reliability, and capacity deferral. Includes the means for increasing hosting capacity through use of smart inverters and storage.

PNM's Plan will enable progression into Phases 2 and 3, and ultimately potentially reaching Phase 4. This progression is dependent upon the capabilities available from the deployment of AMI meters, intelligent field switches and devices, load and DER profiling analysis software, and upgrades to PNM's power flow analysis software. PNM Figure OBW-1 above, as well as the Plan (PNM Exhibit LES-3), identify the deployment timeframe for these functionalities during PNM's 6-year Plan. These investments will enable PNM to further develop hosting capacity maps, application screening sophistication, and more timely conduct more complex interconnection studies.

Q. HOW DOES PNM'S GRID MODERNIZATION PLAN ADDRESS THE NEED TO ENABLE EV ADOPTION AND MANAGED CHARGING?

A. PNM is addressing this need in several ways. As discussed earlier, the improvements in data and forecasting capabilities will enable PNM's planning to better understand where modernization and grid infrastructure investments may need to be prioritized to enable the larger loads that faster EV charging typically involves. This is particularly the case with fleet charging that can reach nearly 10 MW at a distribution center. For context, 10 MW is about the normal capacity of an entire 12.47kV feeder. Also, the transition away from fossil fuels to carbon-free power for transportation increases the requirements for a reliable and resilient electric grid. The flexibility that PNM is incorporating through intelligent switches, communications, and controls enhances its ability to maintain a reliable grid to ensure customers' EV-charging capability remains operable. The distribution modernization capabilities in this plan will be integrated with demand management capabilities, such as a DERMS, to enable managed charging through EV rates and programs. PNM Figure OBW-1 demonstrates the DERMS capability being deployed in the 6-year implementation window. Further details on the anticipated EV adoption rates and load growth are outlined in the Burns & McDonnell Distribution Technology Roadmap attached as PNM Exhibit OBW-2.

Q. HOW WILL PNM'S GRID MODERNIZATION INVESTMENTS IN THIS CASE ENABLE BUILDING ELECTRIFICATION AND DEMAND RESPONSE PROGRAMS FOR CUSTOMERS?

A. Similar to EV-managed charging, PNM's proposed distribution system upgrades, along with the customer-facing technologies, including AMI and the Customer Energy Management Platform, combine to enable customer transition from fossil fuel energy to carbon-free power for heating, cooling, cooking, and commercial-industrial uses. As with EVs, the increased reliance on electrical power in people's lives and business means that PNM must increase its capabilities to maintain reliability and resilience, particularly in the face of climate impacts. Also, rising average temperatures are changing the shape and magnitude of load growth that is compounded with electrification growth.

Q. HOW WILL PNM'S GRID MODERNIZATION TECHNOLOGIES ENABLE DEMAND RESPONSE PROGRAMS FOR CUSTOMERS?

A. The deployment of grid modernization technologies like AMI will provide PNM with additional data to complement PNM's current suite of demand response programs, perhaps aiding PNM in determining the effectives of those programs and how to design better programs. PNM expects that data from AMI will help it design future demand response programs. A critical first step to future demand response programs is having the data from AMI and processing and understanding that data.

Q. HOW WILL PNM'S GRID MODERNIZATION PLAN SUPPORT GRID RELIABILITY AND RESILIENCE GIVEN INCREASING CLIMATE THREATS?

A. PNM's Plan proposes a significant expansion in its intelligence capability (*i.e.*, AMI and distribution automation sensors) combined with an increase in distribution automation switching capability.[15] These proposed distribution planning and analysis investments combined with climate impact forecasts allow PNM to better understand changing requirements for everyday grid reliability and resilience to major events. These reliability and resilience requirements form a key input into PNM's distribution planning, design standards, and operation. Additionally, this data improves customer service intelligence, allowing PNM to optimize its planned automated and remotely controllable switching capabilities to reduce the number of customers impacted by an outage and reduce the duration of an outage should an outage occur.

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[15] The Burns & McDonnell Distribution Technology Roadmap at Sec. 2.6, for example, provides specific distribution automation recommendations for PNM. *See* PNM Exhibit OBW-2.

Q. WHAT DISTRIBUTION SYSTEM MANAGEMENT EFFICIENCIES WILL BE GAINED AS A RESULT OF THE INVESTMENTS PROPOSED IN THIS CASE?

A. PNM's distribution operational efficiency will be enhanced through the proposed grid modernization investments in several ways. One aspect is greater visibility and analytic capabilities that will allow more sophisticated planning that will improve PNM's investment planning and prioritization leading to improved spend-to-value (*i.e.*, customer and policy) efficiency. Another is distribution operational efficiencies from the expansion of ADMS, field intelligence, automation, and controls to address power outages and customer service quality issues. These grid devices, communications, and software systems enable more automated and remote analysis and control of the system, reducing the time and effort to address these issues by field personnel. These grid modernization investments are required to optimize the PV, energy storage, EV charging, and other advancements on the distribution system, all in support of PNM's carbon-free objectives by 2040.

Q. HOW IS PNM ADDRESSING FUTURE TECHNOLOGY INNOVATION IN ITS 6-YEAR PLAN?

A. PNM's 6-year Plan is based on a least-regrets approach to grid modernization investment. This was done by focusing on the foundational components as identified by the U.S. DOE[16] necessary to support a carbon-free transition. Additionally, PNM is incorporating in its grid and information systems architectures the modularity to adapt to new technologies over time by allowing opportunities for new grid-facing technology advancements to be incorporated. PNM has thoughtfully considered the relative maturity of certain technologies, such as DERMS, to determine when it would be best to implement. This also allows PNM to benefit from further enhancements in these technologies and reduce the technology implementation and premature obsolescence risks. For further discussion, please see the EnerNex Guide at PNM Exhibit LES-2, which is an attachment to the Direct Testimony of PNM witness Sanchez.

Q. PLEASE DESCRIBE THE TIMING OF THESE BENEFITS IN PNM'S PLAN.

A. The initial 6-year Plan is focused on deploying the systems and technologies to derive the benefits described. The data from AMI will begin to provide service territory-wide data at the end of year 4 and the AMI data will be used in multiple ways. For example, distribution planning and analytics will benefit from multiple years of data to refine forecasts, but a single year of data will provide additional

[16] *See* DOE Modern Distribution Grid Next-Generation Distribution System Platform (DSPx), *available at* http://www.doe-dspx.org.

insights for hosting capacity analysis. Additionally, the distribution automation sensors provide the data to the ADMS for use by distribution operators as well as distribution engineering for distribution planning and analytics. However, the FLISR and integrated Volt-Var management capabilities are dependent upon those modules being added to the ADMS and the enabling distribution automation technologies being deployed on the distribution grid. Essentially, the first 6-year implementation period puts the systems and technologies in place to evolve PNM capabilities even further.

Q. HOW IS PNM ADDRESSING ENERGY JUSTICE IN ITS GRID MODERNIZATION PLAN?

A. PNM witness Sanchez describes an Environmental Justice Screening Tool ("EJ Screening Tool" or "Tool") that PNM will utilize to prioritize locations for upgrades first, and assess the impact of its proposed grid modernization projects on communities, particularly disadvantaged communities, in order to develop a mitigation response. A description of the Tool is attached as PNM Exhibit LES-5 to Ms. Sanchez's Direct Testimony.

Grid modernization technologies will be deployed coupled with traditional capital infrastructure investments utilized for feeder rebuilds. The portions of PNM's distribution system that are in the most need to be upgraded for reliability and resilience purposes are typically in the communities with the most dated housing stock. Based on census tract data, PNM also understands that these same communities are often low-income.[17] Grid modernization technology planning, design schemes, and standards will be applied equally on distribution feeders, and application of those planning standards will demonstrate that areas with historically lower reliability performance must be targeted for a prioritized deployment of these technologies. The result will be that low-income communities in PNM's service territory will receive the benefit of improved or enhanced reliability or resilience on a more expedited basis than other customers.[18] And, as PNM seeks to prioritize deployment of grid modernization technologies to these disadvantaged communities, the EJ Screening Tool will be used to develop mitigation actions associated with PNM's planned projects. Additionally, the EJ Screening Tool provides for field canvassing and community outreach to verify impacts on the community, and where necessary, develop a mitigation strategy to address community impacts.

[17] See PNM Exhibit LES-4, attached to the Direct Testimony of PNM witness Laura Sanchez.

[18] PNM's prioritization for deployment is based on customer needs and wants, partially developed from multiple customer surveys conducted by PNM over a number of years in advance of this filing. PNM witness Julie Rowey discusses these surveys, as well as the information PNM obtained from conducting them. Improving or enhancing reliability of power delivery for low-income affected communities aims to address energy justice issues for these communities, ensuring that such individuals have access to the same quality and reliability of power as others in PNM's service territory.

Q. HOW DO THESE BENEFITS ALIGN WITH THE OBJECTIVES OF THE GRID MODERNIZATION STATUTE?

A. My testimony identified above how PNM's deployment of specific technology satisfies the statutory criteria. I add to that discussion here.

Section 62-8-13(B) states that the Commission must review the reasonableness of a proposed grid modernization project based on a set of criteria. One of the criteria is that PNM is "reasonably expected to improve the public utility's electrical system efficiency, reliability, resilience, and security …" *See* Section 62-8-13(B)(1). As discussed above, much of the distribution technology deployments identified in the Plan will enhance reliability and resilience. For example, distribution automation enables circuit reconfiguration to address failure conditions on the distribution system. Additionally, FLISR leverages the ability of the distribution automation devices to rapidly address customer outages and restore power.

Another criteria in the statute is that the projects are "reasonably expected to increase access to and use of clean and renewable energy, with consideration given for increasing access to low-income users and users in underserved communities." *See* Section 62-8-13(B)(3). Section 62-8-13(B)(4) also considers investments "designed to contribute to the reduction of air pollution, including greenhouse gases." Greater integration of DERs and EVs, as well as beneficial electrification, certainly will increase access to and use of clean and renewable energy, including for low-income users or underserved communities, resulting in a reduction in air pollution and greenhouse gases. Additionally, maintaining grid reliability and supporting enhanced resilience, even as the grid transitions to more intermittent renewable resources, ensures a pathway to a carbon-free future where all customers, including low-income customers, benefit.

V. CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. PNM's distribution grid modernization Plan provides net customer benefits through enhanced reliability and resilience, increased integration of DERs, and increased flexibility and optimization of the grid resources. These grid modernization investments are required to optimize the PV, energy storage, EV charging, and other advancements on the distribution system, all in support of PNM's carbon-free objectives by 2040. The integration of all the technologies outlined in the PNM grid modernization Plan are a culmination of industry leading experts and expertise within PNM as to its own grid with the focus on customer needs while delivering on the carbon-free objectives by 2040. All the components of the PNM Plan are critical to the engineering, design and planning, maintenance, and operations of the energy management system on the distribution system, which is one of the key components of PNM's goal to achieve a carbon-free transition by 2040.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

GCG#529866

Omni B. Warner

Educational and Professional Summary

Name: Omni B. Warner

Address: PNM
MS ES24
4201 Edith Blvd. NE
Albuquerque, NM 87107

Position: Director, Distribution Engineering

Education: Bachelor of Science in Electrical Engineering, New Mexico State University, 2001
Master of Science in Electrical Engineering, New Mexico State University, 2009
Energy Executive Course, The University of Idaho, 2019
Professional Engineering in the State of New Mexico, license #18406, 2008

Employment: Employed by PNM since 2011.
Positions held with the Company include:
- Director, Distribution Engineering
- Managing Director, PNM Generation
- Director, SJGS Plant Manager
- Manager, SJGS Maintenance
- Team Manager, SJGS Engineering
- Sr. Engineer, Power Production

PNM Distribution Technology Roadmap Document

prepared by

Burns & McDonnell Engineering Company, Inc.

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ADMS	Advanced Distribution Management System
ALT	Automated Load Transfer
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CVR	Conservation Voltage Reduction
DA	Distributed Automation
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management Systems
DG	Distributed Generation
DMS	Distribution Management System
DOC	Distribution Operations Center
DR	Demand Response
DSC	PNM’s Distribution Standards Committee
DSPF	Distribution System Power Flow
DTS	Dispatcher Training Simulation
EMS	Energy Management System

Abbreviation	Term/Phrase/Name
ESP	Energy Service Provider
EV	Electric Vehicle
FCI	Faulted Circuit Indicator
FLISR	Fault Location, Isolation, and Service Restoration
MFR	Multi-level Feeder Reconfiguration
O&M	Operations & Maintenance
OMS	Outage Management System
OPS	Operations Power Systems
PHEV	Plug-in Hybrid Electric Vehicles
PLC	Power Line Communications
PME	Protective Multiple Earthing
PMU	Phase Measuring Units, Synchro phasors
PNM	Public Service New Mexico
PV	Photo Voltaic
RFI	Remote Fault Indicators
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory Control and Data Acquisition
SPT	Single-Phase Trip
SVC	Static var Compensator

Abbreviation	Term/Phrase/Name
URD	Underground residential distribution
VAR (kvar)	Volt-amp Reactive (Reactive Power)
VVC	Volt-var Control
VVO	Volt-var Optimization

1 EXECUTIVE SUMMARY

PNM is currently in the process of planning an enterprise-wide deployment of smart devices in distribution circuits throughout its territory with the goal of improving or enhancing system operations, system flexibility, reliability, and resiliency, as well as increasing customer options to achieve known customers objectives for a diversified and distributed portfolio of energy resources. An intended outcome of this enterprise-wide deployment is to aid PNM in prioritizing projects for its grid modernization efforts, as well as to achieve PNM's goal of achieving a carbon-free transition by 2040. There are many different solutions, technologies, and approaches to distribution modernization with smart devices, so it is critical to systematically scope, plan, and deploy solutions that will benefit customers, will result in cost-effective deployment, and will support grid evolution until PNM achieves its carbon-free goals in 2040. This report identifies recommendations to PNM for a systematic approach to distribution modernization consistent with PNM's vision of how the grid should evolve over time until a carbon-free transition can be achieved by 2040. A proposed methodology for deployment of smart devices for various scenarios specific to PNM's operations is discussed below, as well as the benefits to PNM's system and customers associated with grid modernization.

Consistent with the Grid Modernization Statute, deployment of the devices and technology discussed below will aid PNM in (1) enhancing its electrical system efficiency, reliability and resiliency; (2) driving operational and system changes that will result in achievement of PNM's carbon-free goals by 2040, ultimately reducing air pollution and greenhouse gases; (3) meeting energy demands through a flexible and more diversified portfolio of resources, particularly resources using clean and renewable energy, by fostering technology that will aid in faster and more distributed energy resource (DER) interconnections; and (4) increasing access for all customers, particularly low-income customer, to clean and renewable energy.[1]

Preliminary Deployment Approach and Criteria

A preliminary deployment approach was used as a criterion for the PNM distribution system to achieve grid modernization, reliability, resiliency, renewable resource integration, system awareness, and operational efficiency objectives. That preliminary approach considered the following:

- Modernizing PNM's distribution grid to facilitate a carbon-free transition by 2040. In the more near term, PNM's goal to modernizing its grid is to empower customers and enhance service to customers. Distribution technology investments primarily support service enhancements, including enhancing reliability of service to customers and

[1] *See* NMSA 1978, § 62-8-13(B)(1), (3) and (4).

resilience, minimizing outage times, increasing DER hosting capacity and speeding up DER interconnections, and increasing operational control of circuits. PNM will need to adapt and modify this plan as both technology changes and the PNM system grows.

- Addressing the quick implementation for identified “low hanging fruit” to enhance distribution grid reliability and resiliency.
- Building and modernizing all distribution feeders by the same standards, regardless of region in New Mexico based upon reliability and age of assets.
- Prioritizing distribution system upgrades in low-income communities to ensure that low-income customers are among the first customers to receive the benefits of PNM’s grid modernization efforts.
- Harmonizing new grid modernization projects and technologies with existing projects or technologies.
- Remaining cognizant of PNM’s current situation in terms of weather, vegetation, available resources, and experience with grid modernization implementation, including timelines for implementing new devices on the PNM system.

Emphasizing low-cost distribution upgrades that do not trigger elaborate efforts with lengthy implementation time and high budgetary requirements.

Benefits

The key benefits of distribution modernization can be broken into six types. (IEEE Smart Distribution Working, 2018)

1. **Financial benefits**: these benefits include emphasizing cost-effective deployment; ensuring for stability of costs; and increasing pricing choices for customers.
2. **Power reliability and power quality benefits**: these benefits include reducing the number and length of outages and the number of momentary outages; ensuring for “efficient” power (more real power, less reactive power); and increasing reliable management of distributed generation in concert with load management and/or microgrids.
3. **Safety and security benefits:** these benefits include increasing visibility into unsafe conditions; avoiding security situations due to devices communicating back to PNM Operations; and increasing physical plant security, cybersecurity, privacy protection, and energy independence.
4. **Energy efficiency benefits:** these benefits include reducing energy usage, demand during peak times and energy losses; and fostering the potential to use “efficiency” as equivalent to “generation” in power system operations.
5. **Energy environmental and conservation benefits:** these benefits include reducing greenhouse gases (GHG) and other pollutants; reducing generation from inefficient energy sources; and increasing the use of renewable sources of energy.

6. **DER integration:** the benefits include optimization and efficiencies as to adoption and integration of DERs on PNM's system. Customer adoption of DER and the use of DERs as a PNM grid resource necessitates the integration of advanced grid technologies into the distribution system to enable cost-effective DER integration and continued reliable power to PNM customers. The advanced technologies from grid modernization will enable PNM to address industry-known issues with DER integration.

The following issues list describes how certain grid modernization technologies, as opposed to more traditional technologies, may be able to address certain distribution issues and benefit PNM's grid.

Table 1: Traditional Technology Options vs. Grid Modernization Technology Options

Issue	Traditional Technologies	Grid Modernization Technologies
Voltage Quality	Voltage regulator installation Distribution transformer upgrades Secondary conductor upgrades	Selective physical upgrades Secondary var controllers Volt-var management Advanced inverters
Customer Engagement	Automated Meter Reading (AMR)	Advanced metering (AMI)
Connectivity	Distribution fiber backbone Radio and cellular networks	Distribution fiber backbone Radio and cellular networks
Situational Awareness	FCI (Flag or light-up) Distribution transformer monitoring equipment Situational awareness software Data Management	FCI (communication capable) Smart Distribution devices and software AMI Situational awareness software

		ADMS, DMS, DERMS
Operational Management	DMS, OMS, DOC, EMS	ADMS, OMS, DOC, EMS
Operational Flexibility	Reconfigure Circuit New Circuit New Substation Transformer	Intelligent distribution reclosers Intelligent distribution switchgear Selective physical upgrades

2 DEPLOYMENT APPROACH AND CRITERIA

HARDWARE BACKGROUND

This section provides general information about the type of hardware PNM is considering, as well as the guidelines for preliminary deployment of hardware/devices in the PNM distribution system. The list below details high-level considerations related to the following devices: FCIs, smart fuses, automated reclosers and switches, and capacitor banks.

2.1 Faulted Circuit Indicators

FCIs are a type of sensor that can be used on the grid to assist in detecting of faults. These can be visual only or may be integrated with SCADA to assist in detecting the location of a fault on a feeder. These may be installed and utilized on both overhead and key underground facilities.

Preliminary Deployment Value: These are low-cost visual indicators of faulted sections in the circuit. Higher-cost variants are available that come equipped with communication capability.

Recommended Deployment Locations: Enumerated below are locations where FCIs can provide reliability and operational benefits.

- Long laterals void of other protection and/or communicating field devices.
- Inaccessible line sections and/or areas with low visibility, i.e. at either end of a line crossing over water, under bridges, in underground residential loops, etc.

Other Preliminary Deployment Considerations: Avoid the use of three-phase devices as they will not indicate the faulted phase(s) in the event of line-ground or line-line faults.

2.2 Smart Fuses:

Preliminary Deployment Value: Smart fuses improve upon traditional fuse operation by allowing faults that are transient in nature to be cleared by reclose operations, thus eliminating truck rolls to replace blown fuses. Smart fuses that operate to lockout provide a visual indication of the faulted line section. This would still require a truck-roll, but the operation would be much faster. For situations when the load currents vary based on PV or EV usage, smart fuses provide flexibility. The “digital” nature of smart fuse allows the dynamic settings for the fuse to accommodate load growth and provide reclosing capability. With added communication modules it can be integrated into the ADMS systems and provide alerts and data about any abnormal events. A need based on fault probability helps in determining whether to replace normal fuses with the smart ones. Any data that can be collected with regard to the distribution line in addition to the fuse status (e.g., voltage, current, temperature, etc.) should be planned for and recorded by the ADMS.

Recommended Deployment Locations: Found below are locations where smart fuses are recommended for installation.

- Existing fuses should be replaced with smart fuses where applicable, particularly in the presence of high photovoltaic generation where a current flows and fault currents vary dependent upon the time of day and load conditions.
- Laterals void of an existing protection device where a conventional fuse is not applicable and a recloser cannot be justified.
- Another instance where smart fuses are favorable to conventional fuses is in the presence of high fault currents. Time modifiers and multipliers can be applied to the curves contained within smart fuses to enable tighter coordination between protective devices in series.

Other Preliminary Deployment Considerations: A sophisticated load flow program should be utilized to determine fault contributions from distributed generators to determine if device interrupting ratings are exceeded or sympathetic tripping is possible.

2.3 Reclosers and Switches:

Preliminary Deployment Value: Reclosers often provide the first level of sectionalizing after the station feeder breaker. Reclosers can also be configured to function as part of automated load transfer schemes, where applicable. PNM primarily uses SCADAmate switches on high ampacity feeder ties.

Recommended Deployment Locations: Below are some considerations to deploy reclosers.

- At a circuit midpoint or at thirds of the circuit dependent upon number of customers, customer loads, customer location within the circuit, and circuit topology.
    - Reclosers should only be installed on overhead lines, underground sectionalizing should be done by pad mounted switchgear.
- At three-phase tie-points between adjacent circuits to set up future automated load transfers
    - SCADAmate switches are to be used for higher ampacities, typically 477 AAC conductor size
- Replace hydraulic reclosers with electronic reclosers
    - *If hydraulic reclosers cannot be replaced in the near term, a modular communication/control box can be added to these reclosers for greater control and functionality*

Other Preliminary Deployment Considerations:

- Enable independent phase operation for three-phase reclosers. A decision about single-phase lockout or three-phase lockout must be made based on the characteristics of customers in the circuit. Loss of phase voltage can damage industrial equipment like large motors.
- Pre-program all relays for at least three settings (for example peak setting, off-peak setting, daylight hours, overnight hours, and storm setting) so that linemen and system operators can manually switch between them easily without mistakes. This is especially important in PNM where the load currents are highly variable with respect to time and the amount of sun exposure.
- Tailor device installations such that automated loop schemes or load transfers can be applied in the future pending a detailed capacity and voltage analysis.
- A sophisticated load flow program must be utilized to determine fault contributions from distributed generators to determine if device interrupting ratings are exceeded or sympathetic tripping is possible.
- Provide protection for all laterals. The use of appropriately placed devices will improve system reliability (reclosers preferred).

2.4 Capacitor banks:

Preliminary Deployment Value: Capacitor banks provide voltage regulation and var support in the circuit to maintain power factor requirements. Switched capacitor banks are preferable to voltage regulators for voltage optimization for circuits with high DER penetration due to bidirectionality features and cost. Specifically, feeders that see a need for voltage support in either direction due to various levels of operation of the DER's. Voltage regulators can be leveraged to optimize the voltage for circuits with little to no DER penetration.

Recommended Deployment Locations: Capacitor banks may be placed in distribution circuits utilizing the following criteria.

- Perform load flow analysis to determine the optimal location
  - *If load flow analysis cannot be performed, refer to "two-thirds rule" i.e. place capacitor bank two-thirds of the distance from the substation to the end of the line and size the capacitor bank to fulfill two-thirds of var requirement*

Other Preliminary Deployment Considerations: Switched capacitor banks are favorable to fixed devices, particularly in the presence of distributed generation. Fixed capacitors placed for volt-var optimization during medium to heavy loading conditions can result in overvoltage during light loading scenarios.

2.5 High-Level General Recommendations

The discussion below highlights a logical approach for implementation of smart devices across the PNM distribution system and offers recommendations with high-level guidelines for the early deployment of distribution hardware, as well as a collection of "best practices" to consider while selecting circuits for early deployment and during the deployment of devices.

As a starting point in evaluating the distribution system, PNM must account for the topology of its distribution circuits. This topology is determined by a variety of features including the number of customers, circuit miles, length of laterals, and location (urban versus suburban), among others. Another key topological consideration for PNM is the concentration of DERs across distribution circuits with respect to geography. That is, distribution circuit deployment in a high DER penetration environment evaluates whether the generation is distributed near the source, at the feeder end, or evenly throughout a circuit. Because of the circuit topology, smart device deployment criteria will vary by circuit. The following considerations are to be used to determine circuit upgrades:

- Perform a detailed load flow and protective device coordination for various scenarios to help with capturing the differences for each circuit.

- Evaluate the location of the DER in a circuit, as location can carry implications with respect to service quality issues for the customer. Heavily concentrated DERs near the end of a circuit will have impacts that differ from those observed when the DERs are concentrated near the station source.
- Where applicable, limit the number of customers on a circuit to minimize exposure to outages (the customer number limit can be determined by PNM engineering and planning departments).
- Resolve compliance by limiting the miles of line between automatic sectionalizing devices in each circuit to minimize exposure to outages (the circuit length limit can be determined internally).
    - Sectionalize at key locations for reliability, for shorter circuits establish a midpoint recloser, for longer circuits between two (2) and four (4) reclosers will be required. This will resolve the compliance with the circuit and sectionalization recommendations laid out in this document.
- Protect all laterals, especially remote laterals, with smart devices having communication capabilities. Different types of laterals must be considered to implement different types of protection devices, for example:
    - A recloser should be placed in a long three-phase or one-phase lateral with more than 70A of load while a smart fuse would suffice for a short lateral with few customers.
    - Depending on the lateral and customers downstream, a recloser, a traditional fuse and/or a combination of FCI and smart fuse must be installed. Laterals with significant PV generation can expose sectionalizing devices to a range of load currents. Sympathetic tripping is a false relay tripping due to unbalanced conditions, high-load conditions or as a result of interconnecting large amount of DER. When a circuit has high DER penetration or unbalanced load, the fault levels increase significantly which results in increased voltage sags. This in turn causes tripping of adjacent circuits. To avoid such sympathetic tripping, smart fuses are favorable to conventional fuses on laterals with high PV.
- Long and short laterals must be defined based on the circuit location (urban versus sub-urban) and the concentration of customers along the lateral.

Figure 1 is demonstrative of a procedure for implementation of smart devices for circuit upgrades to optimize the reliability and resiliency of the PNM distribution system. These guidelines are applicable broadly across all PNM distribution circuits to determine a generalized path forward. Detailed analysis at the individual circuit level will be required to scope precise deployment locations, device sizing, reliability benefits, etc., once a general path forward is determined.

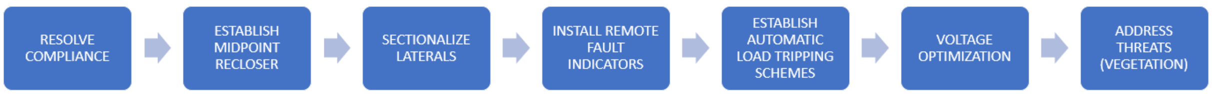

Figure 1: An Example Process Flow for Smart Devices Implementation

The general methodology for the placement and other considerations for reclosers relies on various factors:

- Location of circuit (Urban, Suburban, Rural)
    - An <u>Urban Circuit</u> means that at least 75% of its customers are located in a metropolitan (downtown city or town) area and tends to be densely populated
    - A <u>Suburban Circuit</u> means that at least 75% of its customers are located just outside of a metropolitan area; circuits tend to be longer than Urban circuits
    - A <u>Rural Circuit</u> is not located in a metropolitan area, and customers tend to be spread out and may have pockets of slightly populated areas.
    - The IEEE Distribution Reliability working group defines customer per mile definitions: (IEEE Power and Energy Society, 2022)
        - Rural: > 50 customers per circuit mile
        - Suburban/: 50 to < 150 customers per circuit mile
        - Urban: < 150 customers per circuit mile
- Density of circuit (i.e., number of services on circuit)
    - Circuits with less than 10 customers do not need a recloser but may require sectionalization.
- This must account for commercial and industrial and residential, including critical customers
- Length of circuit backbone, along with intersection points
- Dense vegetation and SAIDI/SAIFI metrics
- **Overhead vs. Underground**
    - Reclosers should not be installed on underground systems
    - Reclosers may be installed before an UG system
- **Underground low voltage networks** (also known as secondary networks) have network protectors on every transformer and are typically in dense downtown areas.

  - Reclosers are not useful in these networks as they are built with transformers and network protectors with automatic protection schemes already programmed into them.
- **Looped circuits** may or may not have normally open switches or reclosers, they tend to be created in halves or quarters with reclosers.
  - The number of customers is not a factor in this scenario.
  - The design standard is to feed 1.5 to 1.75 of the total circuit load when there is an outage, with the faulted section isolated.
    - The number of circuits that can be looped will be assessed by feasibility and reliability metrics.
- **Industrial circuits** which typically have between 1-10 larger customers (commercial campuses fit here).
  - Each customer dedicated transformer or substation and tend to be higher voltage (sub-transmission).
    - Typically, each customer dedicated transformer and/or substation has its own protections, and in many cases the transformers are tapped off the circuit; so during/after an event, the other industrial customers should be unaffected.
    - Reclosers will be all three phases on these circuits
- **Rural circuits** are typically not designed by the number of customers, rather by grouping key customers. For example, if there are two small communities on a single feeder, installing a recloser right after each town would be recommended to keep those groupings (communities) of customers online.
  - PNM has 92 rural circuits.
    - Recommending 2-4 Reclosers per circuit, depending on length and topology
- **Suburban circuits**
  - The first question to ask is “is there a good point to build an Alternative Load Transferring (ALT) Scheme from a neighboring circuit?”
    - If yes, 4 to 6 reclosers per feeder would be recommended.
    - This allows for increased back feed on the system.
  - Forestry, density, and outage history determines the spacing of reclosers, fuses and other protective devices.
  - A rule of thumb is 300-600 customers between devices, however key outage/problem areas to be considered.
    - For example, PNM may have a heavily vegetated or forested area beyond a critical load area. The recloser would not be installed after the forest, rather between the critical load and the forest, keeping the critical load on in the event of a fault.

  - PNM has 99 Suburban circuits.
    - Up to 250 Reclosers are recommended, assuming 2 reclosers exist on each circuit already.
    - Radial circuits and potential loop circuits (ALT) will be assessed by different criteria
- **Urban circuits**
  - Much of the infrastructure tends to be underground, and vaults with space for more equipment are rare.
  - 300-600 customers is the rule of thumb when fully populated, but this is complicated by where it is possible to add smart distribution devices.
  - These Circuits may have as little as 100 customers or as many as 3,000 customers.
    - Sectionalization and Automation should be reviewed whenever feeders and ducts are rebuilt as a core process step.
  - PNM has 281 urban circuits
    - PME Switches are more likely to be used here due to a majority of these areas are underground

2.5.1 Best Practices

The following best practices should be considered to improve reliability and safety.

- Identify the location of critical loads such as hospitals, schools, airports, etc. so that protection or sectionalizing schemes do not inadvertently interrupt service to these loads
- Use common apparatus battery and battery harness for ease of replacement and asset maintenance
- Avoid using three-phase ganged operation for reclosers and other protective devices on long rural circuits and use individual phase operation (also known as single-phase trip (SPT)) if there are no three-phase loads on the circuit. Devices that feature mechanical linkages to operate three phases should be avoided and “triple-single” operation is preferred.
  - A recloser equipped with SPT can reduce the severity of events by allowing at least two-thirds of the customers on a three-phase line to remain energized in the event of a single-phase fault.
  - Careful considerations must be made for placement as circuits must be evaluated for: Impact on three-phase motors; ferroresonance; current and voltage unbalance; backfeed voltage and current; regulatory reporting; and distributed generation.
    - Two-phase open-delta and three phase circuits are examples of where careful considerations must be made before implementing SPT.

- Two-phase open-delta secondaries tie phases through transformers which could cause voltage and fault conditions if additional system protections are not present. These are not common on the PNM system.
- Having a single-phase trip on a three-phase load may damage three-phase devices (such as three-phase motors).

- These reclosers are recommended on rural circuits due to:
  - Most loads are single-phase
  - Travel time required to distribution line
  - Time required to locate fault
  - Time spent transporting repair equipment and supplies to site
- Three-phase gang operated reclosers should be used for sensitive three-phase loads where single-phase tripping would damage the customer load and critical backbone.
  - Allow SPT for line-to-ground faults only if all down-stream loads are able to operate on single-phase basis
  - Trip two phases for line-to-line fault (i.e., two-phase faults)
- SPT can be applied on circuits that are mostly residential with some small commercial loads if it has adaptable protection capability.
  - If no two or three phase motor loads exist on the circuit, having the capability to operate reclosers on a single-phase basis will keep a majority of customers with power when a single-phase fault occurs.
  - Each overcurrent protective element may be individually configured to trip single- or three-phase.
  - Reclosers may be set to:
    - Trip on single phase and lock out on three-phase if the fault is permanent.
    - Trip and lock out on single phase

- Make efforts to sectionalize customer load connected to the distribution grid evenly to minimize outage impacts and loss of service. Set a limit of customers per protection device for example, a mid-point recloser can have between 300 to 500 customers downstream of it.
- Address threats/risks to circuit operation due to excessive vegetation and/or inaccessibility
- Use only a limited set of standard wire sizes for rebuilds and new construction to reduce inventory and stockroom spares

- Apply automated loop schemes and load fail-over where feasible. Feasibility must be determined by the use of a load flow and short-circuit/protection coordination analysis

2.6 Specific Recommendations for PNM's System and Project Cost Estimates

The PNM System consists of the following, resulting in recommendations as noted below for reclosers, and other smart distribution technology:

- 198 substation and switching stations consisting of approximately 632 Feeder Circuits
    - Approximately 210 of these feeders are underground and do not need overhead reclosers
        - These underground feeders are protected with pad-mounted SCADA PME switchgear
    - Approximately 420 of these feeders are overhead. A goal to average 4 reclosers per feeder would anticipate the need for approximately 1600 reclosers on the PNM system.
        - Approximately 400 existing reclosers on the PNM system would leave around 1200 reclosers needed.

The following Distribution Automation recommendations and current PNM-approved vendors and equipment costs are as follows:

- Distribution Automation requirements:
    - 1200 reclosers over the next 10 years.
        - Distribution level recloser vendors include Eaton NOVA three-phase reclosers, S&C IntelliRupters, and G&W Vipers.
            - Some of these reclosers are still under review by PNM Standards and are not approved for use yet.
        - Unit Installation Costs (assuming pole replacement):
            - S&C IntelliRupter $100,000
            - Form6 Eaton Recloser $75,000
            - SEL651RA Eaton Recloser $85,000
                - A majority of the reclosers will be this type
            - G&W Viper $75,000
                - This recloser is in the process of being approved by PNM standards, and is also capable of single-phase tripping
        - O&M

- Each device should be inspected 2 times per year, once for a battery check and once for a multi-point inspection.

- 50 Versa-Techs (single-phase recloser) a year for the next 10-15 years
  - Until all laterals off the backbones are protected and coordinated by either a fuse, the S&C TripSaver, or the Hubbell Versa-Tech recloser.
  - Unit Installation Costs (no pole replacement required):
    - Hubbell VersaTECH $20,000
    - S&C TripSaver $12,000
  - O&M
    - Each device should be inspected 2 times per year, once for a battery check and once for a multi-point inspection.
- 15 S&C SCADA-Mates a year as required.
  - Installation Criteria
    - S&C SCADA-Mates are primarily utilized at points where feeders can tie together for reliability and transferring load between feeders.
  - Unit Installation Costs (no pole replacement typically required):
    - S&C SCADA-Mate $80,000
  - O&M
    - Each device should be inspected 2 times per year, once for a battery check and once for a multi-point inspection.
- Fault Current Indicators (FCIs) to be installed on priority or lines where faults are an issue.
  - Installation Criteria
    - Known feeders where reliability has been an issue
    - Taps where no communication devices are present
  - Multiple FCI's with communication capabilities currently under review by PNM standards
  - Unit installation Costs:
    - Units cost $1200 each
  - O&M
    - O&M is dependent of the length of time the FCIs are installed at given location, but up to 2 times a year is recommended for battery checks.

- PME SCADA Switchgear
  - Unit installation Costs:
    - PME-9 or PME-11 approximately $200,000
  - O&M
    - Each device should be inspected 2 times per year, once for racking the switches to check for proper operation and once for a multi-point inspection.

Table 2: Anticipated Number of Smart Distribution Devices To Be Installed on PNM's System

Device	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Recloser	0	80	80	105	105	105	145	145	145	145	145
Versa-Tech, Tripsavers	0	50	50	50	50	50	50	50	50	50	50
SCADA-Mate	0	15	15	15	15	10	10	10	10	10	10
FCIs (set of three)	0	50	50	50	50	50	50	50	50	50	50
PME SCADA-Switchgear	0	25	25	50	50	50	50	50	50	50	50

Table 3: Estimated Smart Distribution Device Installation, Capital, and O&M Costs

Estimated Device Installation Costs			
Device	**Grid Modernization**	**Capital**	**O&M[1,2] (Per Device Per Year)**
Recloser – IntelliRupter	$93,000	$7,000 (Pole replacement)	$1,320 (Inspection and Battery Replacement)
Recloser – Eaton w/ Form 6 controller	$68,000	$7,000 (Pole replacement)	$1,320 (Inspection and Battery Replacement)
Recloser – Eaton w/ SEL651-RA controller	$78,000	$7,000 (Pole replacement)	$1,320 (Inspection and Battery Replacement)
Recloser – G&W Viper	$68,000	$7,000 (Pole replacement)	$1,320 (Inspection and Battery Replacement)
1PH Recloser VersaTECH	$20,000	$0 (No Pole replacement)	$580 (Inspection and Battery Replacement)
1PH Recloser Tripsaver	$12,000	$0 (No Pole replacement)	$580 (Inspection and Battery Replacement)
SCADA-Mate	$80,000	$0 (No Pole replacement)	$550 (Inspection and Battery Replacement
Fault Current Indicators	$1,500	$0 (No Pole replacement)	$335 (replacement or relocation)
PME SCADA Switchgear	$200,000	$0	$0

1. O&M costs assume a crew of 2 and a bucket truck
2. Recloser O&M costs include 1 battery replacement and 1 multipoint inspection each year

Of these 632 distribution circuits there are approximately (according to https://www.pnmresources.com/about-us/our-businesses.aspx):

- 6,077 pole miles of overhead distribution lines
- 5,962 cable miles of underground distribution lines
- 151,833 transformers serving (per PNM metering):
    - 514,287 residential meters

Table 4: Residential Meter Counts

	# Analog & Digital Display Meters	# TOU Only Meters	# TOU / IDR Meters	# Non-TOU Optical Meters	# OMR Meters	# Installed Meters
Feb	471,431	234	524	318	41,780	514,287

- 59,335 commercial/industrial customers.

Table 5: Commercial Meter Counts

	# Analog & Digital Display Meters	# TOU Only Meters	# TOU / IDR Meters	# Non-TOU Optical Meters	# OMR Meters	# Installed Meters
Feb	41,812	6,879	2,677	6,283	1,684	59,335

- 281 Urban Circuits
- 99 Suburban Circuits
- 92 Rural Circuits
- Appendix A – Population Density Maps of PNM service territory
- Appendix B – Substation Feeders

To improve grid reliability, all laterals off the backbone should have either a recloser or trip-savers (single phase recloser) to keep reliability to the whole feeder.

2.1 EV infrastructure

The below tables are the anticipated cumulative number of EVSE on the PNM system over the next 10 years. These numbers were developed by the PNM Customer Energy Solutions Electric Vehicle group based upon current and anticipated growth in each region by year. This takes into account current state, national, and regional initiatives as well as anticipated residential adoption rates. The following steps and assumptions were used to develop these estimates.

1. Download all data from Federal Alternative Fuel Data Center to see current stations
2. Use the total infrastructure incentives in the Transportation Electrification Plan (TEP) to assume stations installed by 2024 (TEP planned for 2022-2023)

3. For DCFC, after 2024 moderate growth (2-4 stations per year) is assumed for each Geographic Area. This comes to 34 per year for PNM service area.
4. Looking at an S-curve adoption forecast, the total number of EVs each year in PNM service area is estimated.
    a. General assumptions used to calculate number of home and public Level 2 stations growing with overall EV adoption
5. Assume the average Level 2 charger is 7 kW and average DCFC is 100kW
6. The annual number of chargers and associated capacity is calculated

Table 6: Anticipated EV Level 2 and DCFC Growth on PNM's System Over the Next 10 Years

Year	Number of Level 2	Capacity of Level 2 [MW]	Number of DCFC	Capacity of DCFC [MW]	Total Capacity [MW]
Current	1476	10.3	93	9.3	19.6
2022	4507	31.5	93	9.3	40.8
2023	7385	51.7	129	12.9	64.6
2024	9958	69.7	163	16.3	86.0
2025	13999	98.0	197	19.7	117.7
2026	20258	141.8	231	23.1	164.9
2027	29791	208.5	265	26.5	235.0
2028	43956	307.7	299	29.9	337.6
2029	64338	450.4	333	33.3	483.7
2030	92541	647.8	367	36.7	684.5
2031	129847	908.9	401	40.1	949.0

3 FUNCTION OF SMART DISTRIBUTION AUTOMATION

According to the IEEE Distribution Automation Working Group white paper entitled "Smart Grid for Distribution Systems: The Benefits and Challenges of Distribution Automation (DA)" (IEEE Smart Distribution Working, 2018), distribution automation has primary and secondary functions that benefit the electric distribution system. This section serves as a guide for PNM to consider as more smart distribution devices are implemented on PNM's distribution system but does not serve as specific recommendations for PNM's system in the near-term.

3.1 Primary Distribution Automation Functions

1. Monitoring and control of distribution equipment within substations
2. Distribution SCADA System Monitors Distribution Equipment in Substations
3. Supervisory Control on Substation Distribution Equipment
4. Substation Protection Equipment Performs System Protection Actions
5. Reclosers in Substations
6. Local automation of DA equipment on feeders

7. Local Automated Switch Management
8. Local Volt/var Control
9. Local Field Crew Communications to Underground Network Equipment
10. Monitoring and control of DA equipment on feeders
11. SCADA Communications to Automated Feeder Equipment
12. SCADA Communications to Underground Distribution Vaults
13. Management of Distributed Energy Resources (DER) systems
14. Protection Equipment Performs System Protection Actions on DER Interconnections
15. Monitoring of DER Units
16. Controlling DER Units
17. DA analysis software applications
18. Study-Mode and Real-Time Distribution System Power Flow (DSPF) Model
19. DSPF /DER Model of Distribution Operations with Significant DER Generation/Storage
20. Advanced Metering Infrastructure (AMI)
21. Implementation of AMI to Industrial, Commercial, and Residential Customers
22. Direct Customer Load Control

3.2 Secondary Distribution Automation Functions

3.2.1 Operational DA Functions

1. Real-time normal distribution SCADA operations to substations
    a. Alarm Processing
    b. Distributed Energy Resources (DER) in Substations
    c. SCADA System Provides Data to Mobile Computing Devices
2. Local automation of feeder equipment beyond substations
    a. Reclosers Interact with Field Equipment
    b. Local Field Crew Communications from Automated Feeder Equipment to assist with troubleshooting the locations of faults
3. Remote monitoring and control of automated feeder equipment, possibly using the AMI system for communications
4. Normal distribution operations using the Distribution System Power Flow (DSPF) model
    a. Adequacy Analysis of the Distribution System to Meet the Load
    b. Reliability Analysis of Distribution System to Minimize Outages
    c. Contingency Analysis (CA) of Distribution System
    d. Efficiency Analysis of Distribution System
    e. Optimal Volt/var Control of Distribution System
    f. Relay Protection Re-coordination (RPR) of Distribution System
5. Emergency distribution operations using the DSPF model
    a. SCADA System Performs Disturbance Monitoring
    b. Automated Fault Location, Fault Isolation, and Service Restoration (FLISR)
    c. Multi-level Feeder Reconfiguration (MFR) – This is to reconfigure feeders to accommodate load transferring between feeders where possible
    d. Load Management Activities for Emergency Conditions
    e. Mitigating the Effects of Major Storms, Extreme Weather Events, and other Disasters
    f. Enhancing Repair Activities After Major Disasters

6. Distribution system operations training and assessments using the DSPF model
    a. Dispatcher Training Simulation (DTS)
    b. Audit Logging and Reporting Diagnostic Analyses of Events

3.2.2 Automated Distribution Systems - with Significant DER

1. Planning for interconnection of DER to the distribution system
    a. Assessment of Proposed DER Interconnections
    b. Engineering, Monitoring, and Analyzing DER Interconnections
2. Energy Service Provider (ESP) management of DER units
    a. ESP Monitors Non-Operational Data from DER Site
    b. ESP Manages Market Operations of DER Units
3. Local and basic SCADA operations with DER units
    a. Utility SCADA Monitoring and Control of DER Units
    b. Supervisory Control of Switching Operations with Significant DER
    c. Local Automated Switching Operations (IntelliTeam) with Significant DER
4. Normal distribution operations with significant DER using DSPF / DER models
    a. Adequacy Analysis of Distribution System with Significant DER Generation/Storage
    b. Reliability Analysis with Significant DER Generation/Storage
    c. Contingency Analysis with Significant DER Generation/Storage
    d. Efficiency Analysis with Significant DER Generation/Storage
    e. Optimal Volt/var Control with Significant DER Generation/Storage
    f. Relay Protection Re-coordination (RPR) with Significant DER Generation/Storage
    g. Assessment of the Impact of/on DER Generation/Storage during Distribution Planned Outages
5. Emergency distribution operations with significant DER using DSPF / DER models
    a. Fault Location, Fault Isolation, and Service Restoration (FLISR) with Significant DER Generation/Storage
    b. Multi-Level Feeder Reconfiguration (MFR) with Significant DER Generation/Storage
    c. Post-Emergency Assessment of DER Responses and Actions
6. Customer-driven actions with significant DER generation / storage
    a. Planned Establishment of Temporary Microgrids
    b. Emergency Establishment of Microgrids during Power Outage or Other Emergencies
7. Enabled load shedding, demand response

3.2.3 Customer interactions related to automation

1. Use of Advanced Metering Infrastructure (AMI) information in distribution operations
    a. Automated meter reading to send meter data directly to PNM without the need to send meter readers out to customer meters
    b. Customer Outage Detection and Correlation to Fault Location
    c. Assessment of Customer Power Quality
2. Customer demand response
    a. Customer Response to Demand Response Signals
    b. Analysis of Demand Response
    c. Demand Response Interactions with Home Automation Networks
3. Customer use of DER generation / storage

   a. Customer Use of DER for Self-Supply
   b. Electric Vehicle (EV) and Plug-in Hybrid Electric Vehicle (PHEV) as Combined DER Generation and Storage
   c. DER Units Bid into Market Operations

3.2.4 Distribution Planning

1. Operational planning
   a. Assessing Planned Outages
   b. Storm Condition Planning
2. Short-term distribution planning
   a. Short-Term Load Forecast
   b. Short-Term DER Generation and Storage Impact Studies
3. Long-term distribution planning
   a. Long-Term Load Forecasts by Area
   b. Optimal Placements of Switches, Capacitors, Regulators, and DER
   c. Distribution System Upgrades and Extensions
   d. Distribution Financial Planners

3.2.5 Maintenance, Engineering, and Construction

1. Distribution system equipment maintenance
   a. Predictive Maintenance Application Assesses Distribution Equipment
   b. Management of Maintenance Assets
   c. Scheduling of Maintenance and Equipment Replacement
   d. Maintenance Updates to Documentation and Maps
   e. Maintenance of DSPF Model and Other DA Applications
2. Distribution system design and engineering
   a. Design and Engineering of Substations and Feeders
   b. Specification of Distribution Equipment
3. Construction management
   a. Asset Tracking and Updating
   b. Planning Construction Projects

3.3 Significant DERs

The definition of ‘significant DERs’ varies by the feeder they are installed on. DERs may include:

1. Generation sources located on the distribution system, such as solar photovoltaic (PV) systems, wind generators, hydro generation, geothermal generators, natural gas, and diesel generators
2. Battery electric storage systems
3. Demand response and transactive energy systems
4. Energy efficiency technologies.

Significant DERs is defined by performing a hosting capacity study on each feeder on a distribution system. Hosting capacity is defined by the amount of DER that can be accommodated without impacting power quality or reliability under existing control and infrastructure configurations. Without the hosting capacity analysis, distribution systems may be subject to: (Rylander, Rogers, & Smith, 2015)

- Overvoltage
  - The hosting capacity on a particular feeder will be dependent on the thresholds used for the calculation. Operating conditions such as conservation voltage reduction (CVR) could reduce the hosting capacity. These feeders may have additional headroom before reaching the ANSI voltage limits, but the operating strategy may dictate the voltages be kept at lower levels.
  - Voltage Deviations
    - Voltage changes (deviations) may not have a strict ANSI threshold; however, they could cause voltages to suddenly swing above/below operating limits. In addition, this can cause additional control (regulator/capacitor) operations or tripping of sensitive equipment.
- Protection
  - Distributed generation has the potential to disrupt protection schemes and requires evaluation. The fault contribution from inverter-based generation can be short in duration due to fast acting controls; however, the magnitude will be based on the inverter control and not the impedance to the fault. In other words, the fault contribution will be in the range of 1-2 times the full load current and potentially higher.
- Unbalance During Faults
  - The fast acting (tripping) of inverters can limit the fault contribution; however, can also lead to additional issues especially in the presence of higher ground fault currents. In the case of a single-phase fault, all inverters of that particular phase can trip, causing the ground currents to jump at the substation. This change in ground current can inadvertently cause the substation ground fault relay to trip the feeder.
- Unintentional Islanding
  - Anti-islanding remains a concern as well even with the presence of inverter destabilization controls that are constantly searching for the islanded condition. An issue with these destabilization controls is that conflicting objectives between various brands of inverters can potentially delay or miss the detection of an island before automatic feeder control devices try to reclose on the island. Using a direct transfer trip or making sure the total PV does not exceed the local load are the most definite ways to prevent an unintentional island but would either add significant cost or severely limit the amount of PV on the feeder.

4 GRID MODERNIZATION EQUIPMENT APPROVAL PROCESS

4.1 PNM Standards Approval Process

PNM has many existing approved grid modernization devices that are ready to be implemented on the PNM distribution grid. Most of the existing technology laid out in this document has already been approved for use by PNM. As new technologies are developed or considered by PNM for adoption onto the grid a similar process will be maintained.

4.2 Current Equipment and Research

This section details the existing technology approved for PNM use by the PNM standards department.

4.2.1 Three-Phase Reclosers

- *Currently*: Primarily install SCADA-controlled NOVAs with SEL 651RA controllers for all new installations. IntelliRupters approved, but not used as reclosers in our protection scheme. No proactive change out.
- *Recommendation*:
  - Research if IntelliRupters or other reclosers with pulse-closing technology can be used in all recloser applications. Research the SEL 651RA and other controllers for high impedance fault detection, fast trip, wire down, falling conductor and other settings. Once as equipment plan is established, change out can occur. Proactive change out would be beneficial in HFAs on per circuit basis.
  - Research G&W Viper Reclosers
- *Benefit*:
  - IntelliRupters with pulse-closing technology reduce the energy released during recloses by up to 95% which reduces stress on on transformers, connectors, insulators and conductors and fault energy released. Traditional reclosers with repeated operations can fail equipment and lead to failures.
  - Viper Research update
    - Viper-ST
      - One single control cable brings all current, voltage, breaker status and trip/close information into the control
- *Challenges*:
  - Implementation concerns related to staffing consideration. SCADA may not be able to be connected due to no signal (remote mountainous areas) or lack of bandwidth (Albuquerque). Presently 26-week lead time on IntelliRupters, and lead time other reclosers and controllers is similar.
  - Challenges for using the Viper
    - SEL-651RA recloser control that is preferred by PNM is only compatible with the Viper-S due to the control's inability to trip individual phases

- Installation of Viper-ST would require replacement of both recloser and control

4.2.2 Single-phase reclosers / TripSavers IIs

- *Currently:* PNM has installed some TripSaver IIs in select single phase lateral locations based from a protection analysis or fuse operation analysis.
- *Recommendation:* Set up a criteria on when to use TripSaver IIs or other single phase reclosers (number of fuse trips over certain time period, exceeding specific load, exceeding specific customers count, SAIDI minutes at location) and replace with reclosers.
- *Benefit:* Most fuses expel debris and sparks when they operate for both temporary and permanent faults. However, in place of the fuse, TripSaver II reclosers use vacuum interrupters that do not expel debris.
- *Challenges:* Implementation concerns related to staffing consideration. .
- *Priority:* Medium.

4.2.3 Capacitor Banks

- *Currently:* Capacitors banks are in the process of being equipped with SCADA communication in order to send real-time data back to DOC. A feature included in the bank is neutral current sensing – it can detect when a bank has either a blown fuse, a bad capacitor can or a stuck switch.
- *Recommendation:* As of now PNM is getting data back on the status of the bank: on neutral sensing, voltage sensing and counter operation. Going forward, more research would need to be conducted on other features the controller offers, i.e. harmonic sensing,
- *Benefit:* Having SCADA equipped capacitor banks are benefiting distribution planning to give more accurate modeling and sending live data to DOC to make decision if a bank is not functioning correctly. If the bank isn't operating properly, troubleshooting or forced operation could create an arc flash.
- *Challenges:* The additional labor to change out old Beckwith controllers with this new updated controller. Communication bandwidth may not be compatible in certain locations.
- *Priority:* Medium as this is a continuous process.

4.2.4 Communicated Fault Current Indicator (FCI)

- There are different FCI products available on the market by different manufacturers like SEL, Aclara, Fisher Pierce, Eaton, and Power Delivery Products. Lot of these manufacturers are providing communicative FCI's which have Fault response time in milliseconds and can remotely share permanent as well as temporary fault details recorded on circuit. Communicative FCI's also comes with the feature of measuring different distribution circuit parameters like voltage and current and can share that data through LTE, wireless or gateway communication and can be integrated into SCADA system which gives distribution system operators better visibility into system conditions and speed up fault location.
- *Currently*: A standard FCI from SEL with Flag type indicator is being utilized on overhead distribution circuits only, and crews must manually locate an FCI to determine if a fault is on the line. No FCI's used for underground circuit network.

- *Recommendation*: Utilizing SEL-FLT and SEL-FLR system can give guidance to DOC to determine if a hazard is occurring on the line.
- *Benefit*: Reduces time to locate fault. Minimizes the outage duration. The device can distinguish between permanent and temporary faults or losses of load in applications where automatic reclosing is applied. Addition to fault indication communicative FCI's can also record circuit performance data for different parameters which can be helpful for future DER integration and modeling.
- *Challenges*: Identifying the distribution circuits and ideal FCI installation locations for trial run in PNM network where different Fault criteria can be tested. cost for annual maintenance of the device.
- *Priority*: Medium as more research and trial needs to be conducted.

5 SMART DEVICE INSTALLATION METHODOLOGY

The section below demonstrates sectionalizing and load transfer process for a typical PNM distribution circuit. The figures detail the reliability benefits that can be achieved by implementing smart devices discussed in Section 1 above and automatic load transfer schemes across the service territory by minimizing the number of customers affected and the durations of outages.

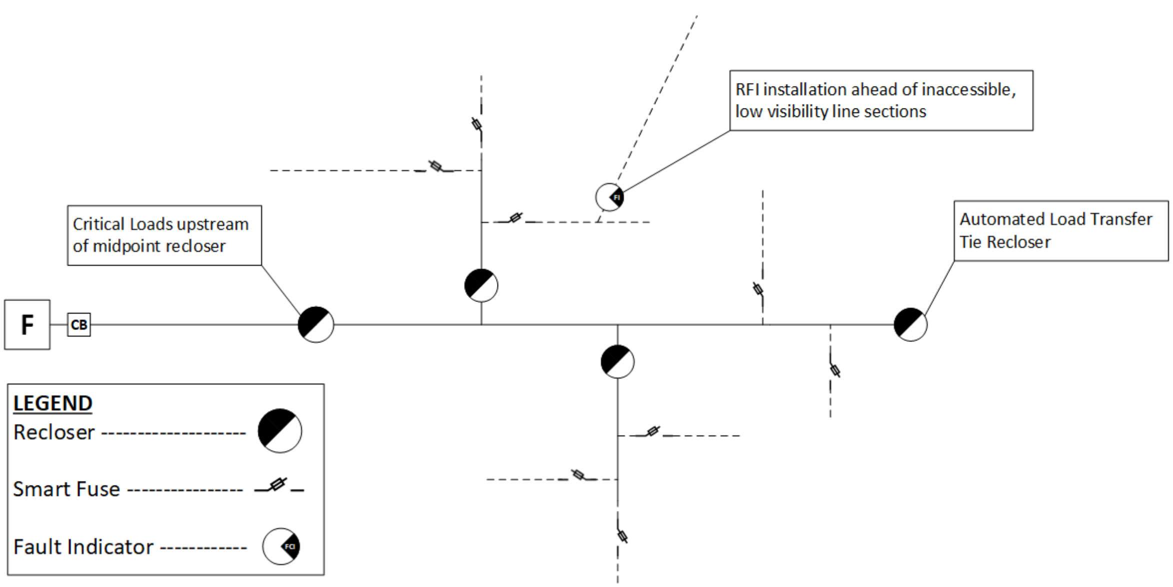

Figure 2: Sample One-Line Diagram for Sectionalization

Figure 2 details an adjacent circuit that could serve as a “team member” in an automatic load transfer scheme. Note that each circuit has a normally closed midpoint recloser and the tie point is equipped with a normally open tie recloser. The protection devices in each circuit must be coordinated to clear faulted line sections while minimizing the interruption to the customers. The curves, pickup values, and other associated settings of interrupting devices should be stored as the “normal” operation state.

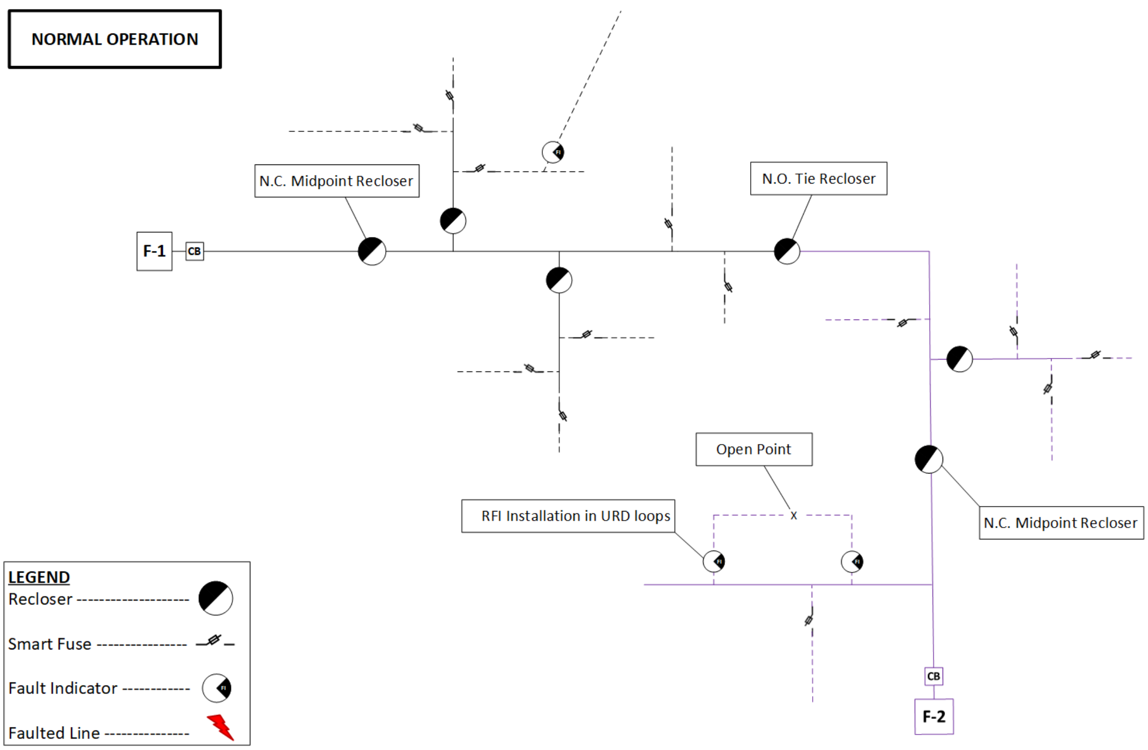

Figure 3: Normal Operation of Adjacent Circuits

Figure 3 demonstrates when a fault occurs in a critical location close to the station source. The assumption below is that the fault is observed by the station relays and the station breaker subsequently operates to lockout, i.e. no service to all the customers of feeder F-1. A fault scenario like this has the potential to significantly affect the reliability scores of a utility. Line sections highlighted in red are indicative of a loss of electric service.

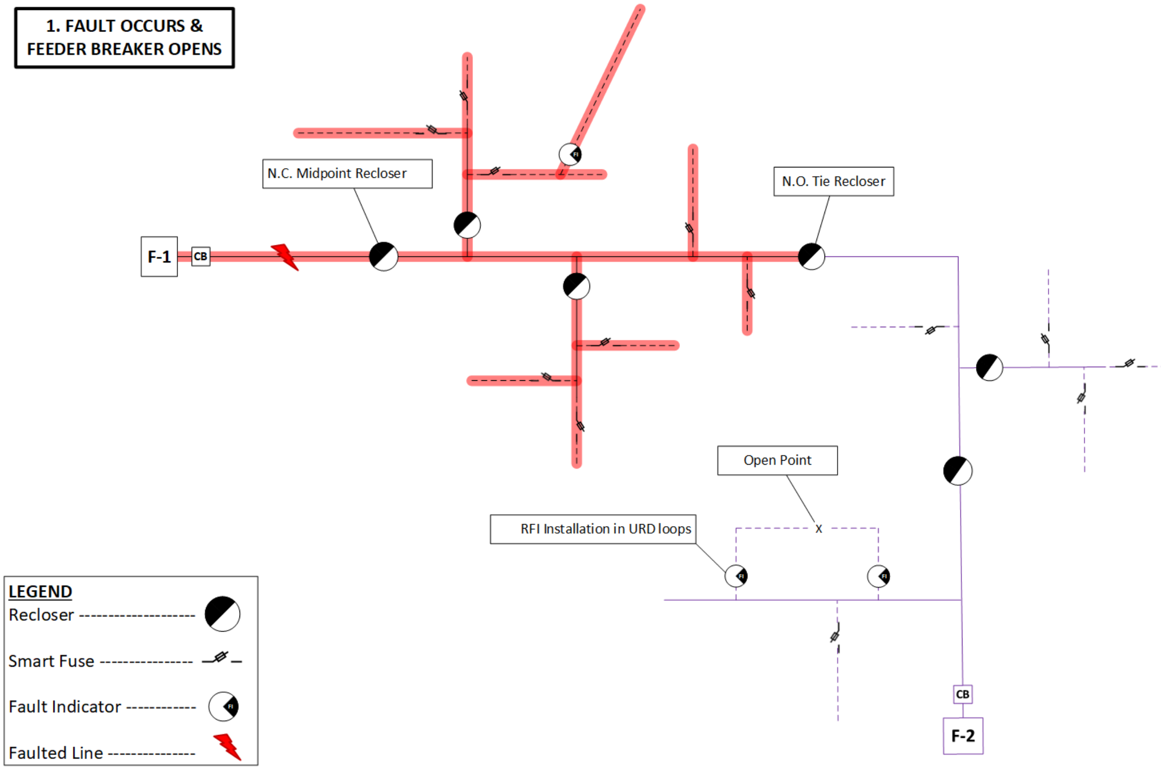

Figure 4: Fault Scenario Imposed on Feeder F-1

Provided that the proper recloser logic and settings are in place and communications capability exists in the circuits, Figure 4 shows the process by which service is restored to a significant number of customers in the circuit. The normally closed midpoint recloser in F-1 should open and the tie recloser between the two circuits should close. Those customers in Feeder F-1 downline of the midpoint recloser will now be served by the source at Feeder F-2. This functionality is only successful when all device settings, logics, and communications are in place. Lines with restored service now fed from Feeder F-2 are highlighted in green in figure below.

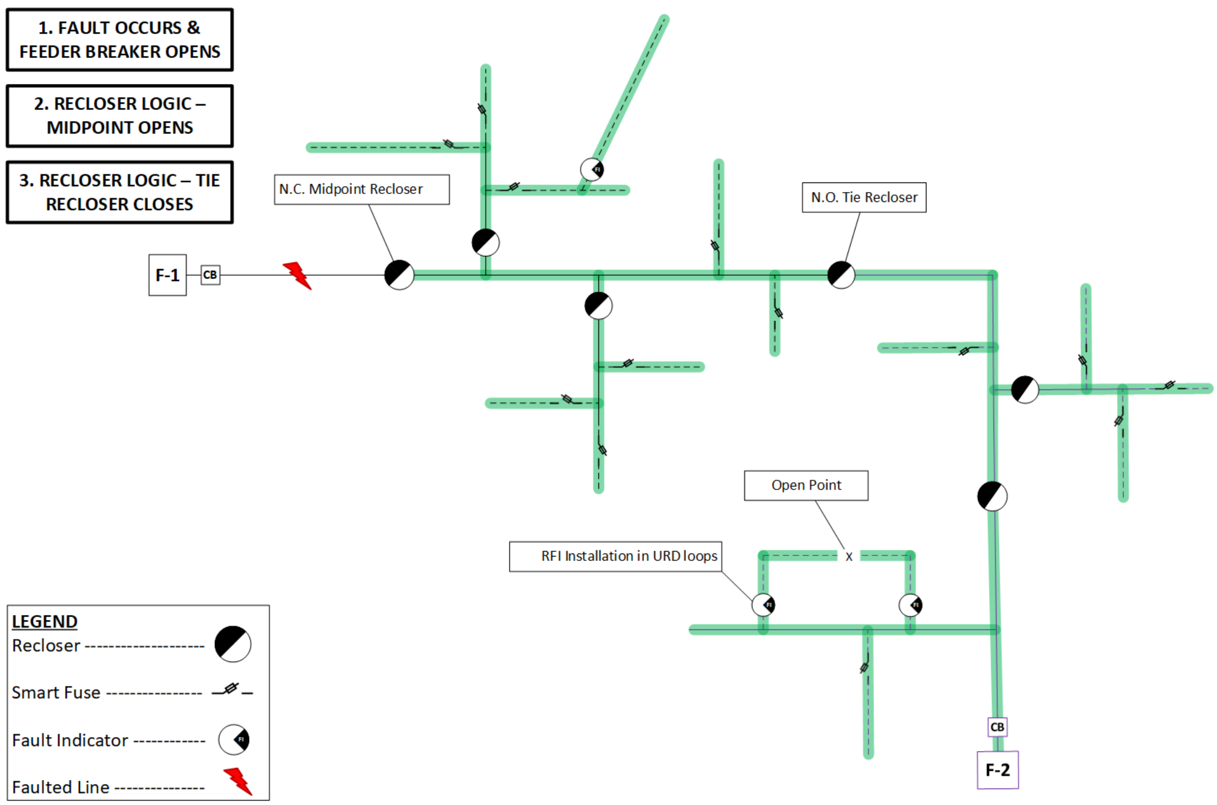

Figure 5: Automatic Load Transfer

Figure 5 and Figure 6 notes that the cause of the fault near the station must be addressed by the utility to restore service to any customers between the feeder breaker and the now open midpoint recloser before returning to a normal state of operation. During this contingency state, the device settings of the protection devices will likely no longer coordinate appropriately. To rectify this situation, each device that is capable of storing dynamic settings should switch to the pre-programmed settings developed, in advance, specifically for this scenario.

Load flows and short circuit analysis in the system model will be necessary to determine whether the circuit "picking up" the transferred circuit has sufficient capacity in the backbone to carry the transferred load and whether short circuit duties are exceeded in the devices in the transferred circuit. Fault current magnitudes may vary dependent upon a number of factors including the fault current contribution from the new source, conductor impedances, and the degree to which photovoltaic generation is contributing to the fault current.

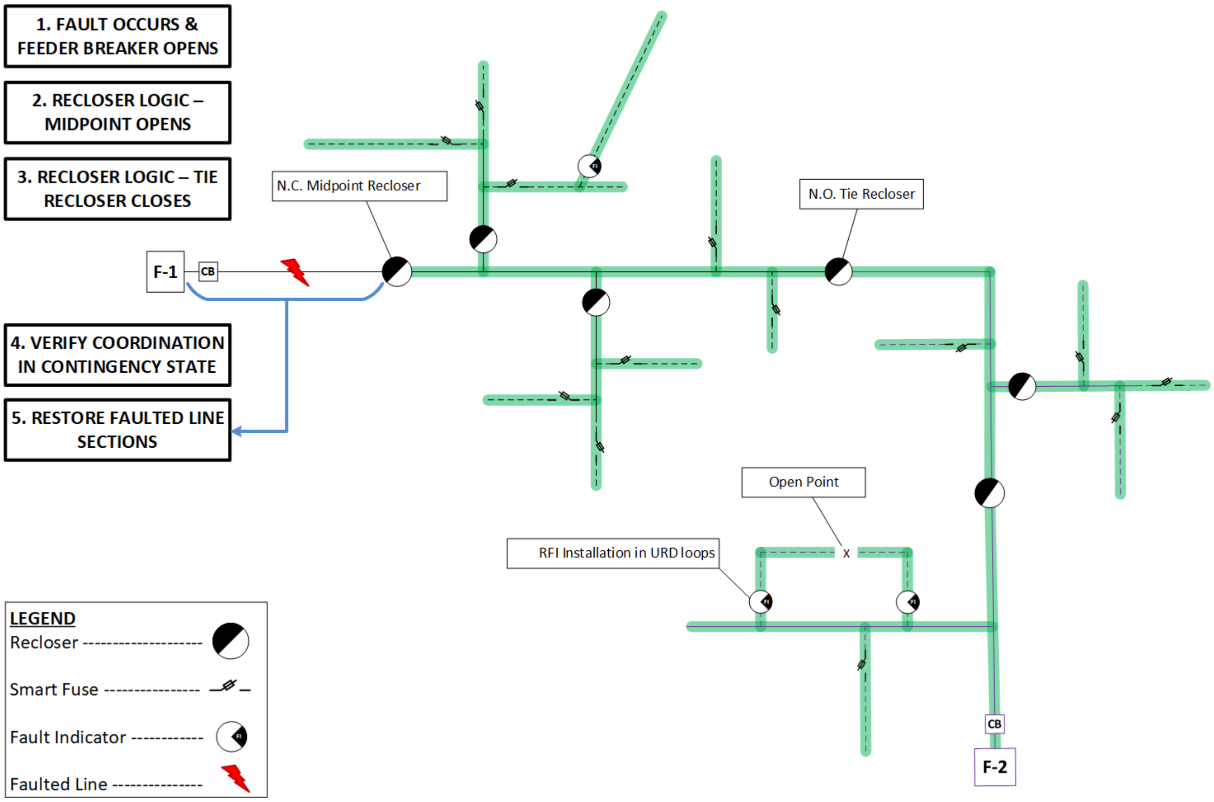

Figure 6: Contingency Operation

In concert with the implementation of Automated Load Transfer (ALT) schemes and deployment of smart devices, it is recommended that PNM begin the practice of recording salient events recorded by deployed smart devices. AMI meters can be configured to record voltage disturbances at the customer service entrance and modern distribution devices including reclosers and capacitor banks are capable of sensing, recording, and reporting voltage events on the line, and thus affected customers downstream. Analysis of waveform data can provide valuable insight into the cause of the voltage event. Voltage event reports should include the number of customers affected, regardless of the way the event is captured.

In addition to capturing voltage disturbances, fault events should be captured in a similar manner. The systematic logging of fault data can assist planners in developing protection schemes that properly coordinate devices and clear faulted conditions quickly and permanently, minimizing risk of hazard to personnel, customers, and equipment. Analysis of a fault log will alert system engineers of devices that are not functioning properly by comparing expected operation against actual field performance. Fault data can also indicate the success rate of existing sectionalizing practices.

Capturing these data in PNM distribution circuits is especially important given the topologies of the circuits and the high levels of DER penetration. DER can impact the power quality in a distribution system in a multitude of ways and it is important that the correct data are being collected and analyzed so that when power quality is negatively affected, mitigation efforts can be developed.

Distribution circuits across the PNM service territory vary widely. The sections below provide early deployment guidelines and considerations related to the following circuit features: level of DER penetration, characteristics of load (residential/commercial/industrial), topology, overhead and underground sections, and load transfer capability. Each of these features and associated early deployment implications are discussed in further detail below.

5.1 Level of DER Penetration

A high level of distributed energy resource (DER) penetration is assumed when the amount of generation attributable to DER is near to or higher than the total load on a circuit during minimal load conditions. A low level of DER penetration is assumed when the amount of generation attributable to DER has little impact on the total load in a circuit during minimal load conditions.

A DER can be defined as a small, modular, energy storage or generation technology that may provide electrical capacity on the electrical distribution grid. This may include PV, EV and EV charging infrastructure, wind turbines, batteries, cogeneration and other energy storage systems.

- Regardless of the level of DER penetration, load forecasts must account for DER penetration in each circuit and if metering capability permits, the development of hourly load profiles is encouraged for use in circuit selection criteria and modeling for time series analysis
- In circuits with a high level of DER penetration, system models must account for feeder loading at critical hours of the day to reveal "hidden" load attributable to DER - all protective devices must be sized to take this hidden load into consideration and device settings should be stored that accommodate system conditions at the various conditions throughout the day
- Anti-islanding protection schemes must be deployed in circuits with high levels of DER to avoid safety concerns for personnel and closing in on an island that is operating out of phase with the grid
- A load flow analysis should be conducted to determine the extent to which DER penetration in the circuits under review has caused increases or decreases to fault current magnitudes and whether over-voltage and/or back-feed issues are present/possible.

- Voltage issues will be a common problem and must be studied extensively. For circuits with high DER penetration, capacitor banks instead of voltage regulators should be used for voltage issues.
- Protective devices must be coordinated properly to ensure proper isolation and operation during all loading scenarios and DER output levels including back-feed scenarios. This will require careful study for various scenarios especially day and night loading profiles.

During the day, when there is plenty of PV generation, the direction of the real power flow may back-feed onto the substation bus. This scenario has several implications, such as but not limited to voltage rise, protection coordination, and load tap changer settings. Also has implications on the transmission studies, protection, and design, this can lead to lengthy and expensive transmission upgrades to mitigate these effects.

Additionally, current flows through major laterals can vary widely dependent upon whether the sun is shining. For example, a major residential lateral may see 38 amps of continuous load current *out* of the lateral and into the backbone. Switching all PV generation off, however, the lateral may see 30 amps of continuous load current *into* the residential area from the backbone.

As mentioned above, continuous currents observed by protective devices will change dependent upon the time of day and level of PV generation. It is essential that various loading and generation scenarios are modeled to ensure that device settings can accommodate the full range of circuit conditions and that sympathetic tripping of devices is not an issue. Sympathetic tripping is a false relay tripping due to unbalanced or high-load conditions. In addition, protective devices are likely to see a varying range of fault currents dependent upon the level of PV generation. Devices should be configured with multiple pre-programmed settings to accommodate these variances in both load currents and fault currents.

5.2 Residential versus Commercial/Industrial Customer

A residential circuit is usually comprised of mostly single-phase loads, whereas commercial/industrial circuits serve primarily three-phase loads. Commercial/Industrial loads are often much larger than a typical residential load but can include multi-family dwelling units. PNM is faced with the proliferation of high-density residential customers (due to high rises) along with several remote customers. They also have an increased need to serve new commercial customers. Below are some preliminary deployment considerations related to the characteristics of the load and/or customer.

5.2.1 Commercial/Industrial

Recloser application will vary dependent upon whether the load in the circuit under review is primarily residential/small commercial or large commercial/industrial. Program protective devices for storm conditions especially for important customers and utilize and integrate loggers (existing in most reclosers).

- Traditional reclosing practice in heavily industrialized areas is discouraged, as the risk of repeated exposure to in-rush currents or closing in on residual voltages out of phase with the grid can damage motors and similar equipment – deploy "smart" devices where feasible

- Single phase lockouts on three-phase loads can damage some equipment including large industrial motors. It may be desirable to avoid single phase lockouts in circuits with primarily three-phase loads while the responsibility of protecting remote three-phase loads may be deferred to the customer

- A sophisticated load flow model should be utilized to ensure power delivery is within the bounds of applicable standards and high reliability is maintained in all scenarios

- Incorporate automatic load transfer schemes for large/important customer circuits so that in the event of a fault, an interruption in service is not experienced

- For industrial customers with rotating machinery use smart fuses and sectionalizers for protection of the customers' systems and sectionalization of circuits.

- Leverage voltage regulator where applicable for "industrial customers" to provide stable voltage. Typically, the circuits feeding industrial customers have small laterals and little to no DER penetration, hence voltage regulator provides more flexibility in terms of voltage optimization.

5.2.2 Residential

Residential circuits can be divided into high density residential circuits and normal to low density residential circuits. The customer density in PNM circuits ranges from as high as 724 customers per mile in urban centers to as low as 2 customers per mile in rural circuits. The average customer density across all distribution circuits is 108 customers per mile. For the guidelines purpose, a high-density residential circuit has more than 200 customers per mile. Note that this number can be adjusted based on internal PNM discussion.

- For circuits with a high density of customers, utilize smart fuses so that faults that are transient in nature can be cleared through reclosing attempts – permanent faults are still isolated when the device operates to lockout
- Incorporate fault and waveform loggers for high density residential customers. Program protective devices for storm protection
- For those lower density, remote residential circuits with lower generation from photovoltaics conventional fuses are in many instances acceptable

5.3 Overhead vs Underground

Device deployment methodology and associated settings in distribution circuits that are predominantly underground will vary from those used in predominantly overhead circuits. PNM should try to add fault loggers at the beginning section of each underground section.

- FCIs should be installed in long sections of conductor without any other sectionalizing or communicating device.
- FCIs with communication should be installed in overhead sections that run through backlots or anywhere that crew accessibility and/or visibility is compromised.
- FCIs with communication capability can be installed in each end of an Underground Residential Distribution (URD) loop or on transformers and sectionalizing cabinets to hasten the location and subsequent isolation of faulted sections.
- Communications systems in underground circuits are vital to effective, efficient operation. It is recommended that PNM deploy pilot programs utilizing systems from a number of vendors to determine the system that is the best solution for PNM. Figure 7 below shows potential location of RFIs for underground lines in a circuit.

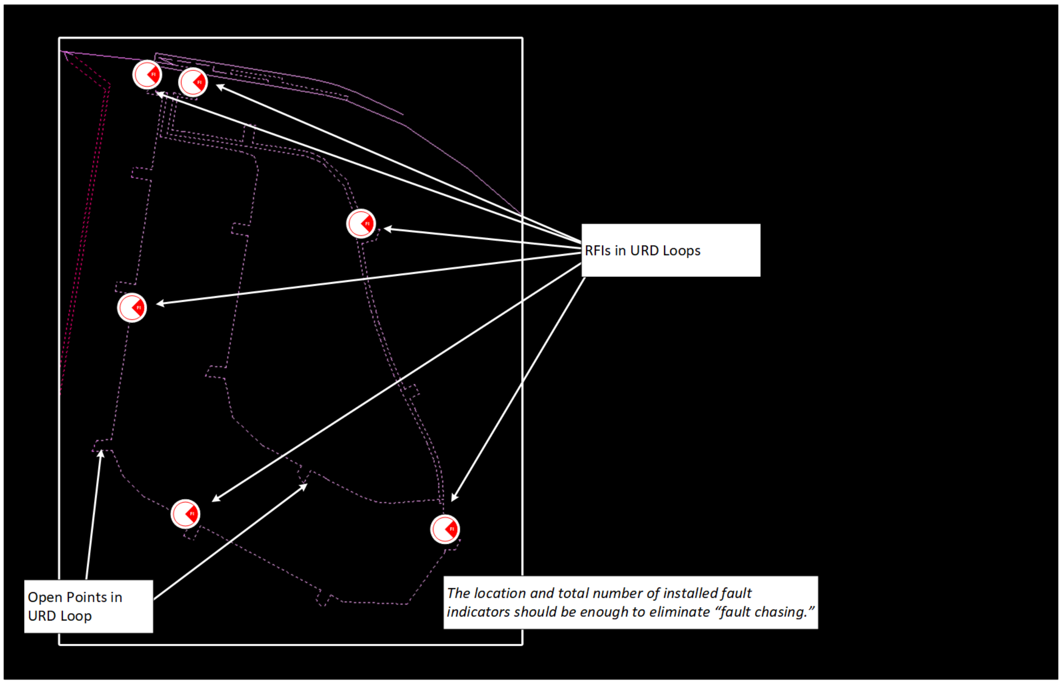

Figure 7: Sample Locations of RFIs in Underground Lines

- When setting reclosing sequences and intervals for devices protecting underground circuits, the incidence of permanent faults on underground lines is a key consideration. Use of smart reclosers exclusively is encouraged
- Permanent faults are more prevalent on underground lines, and as such, lengthy reclosing intervals are discouraged to limit device exposure to repeated fault currents of high magnitude. Ensure use of backbone smart reclosers
- Underground cable construction should account for "Neher-McGrath" calculations, i.e. ampacity derating, as a result of soil type, conductor configuration, burial depth, etc.

5.4 Load Transfer Capability

Ideally load transfer capability is used to increase reliability and thus circuits/customers requiring this capability should be prioritized. Below are some considerations to enable load transfer schemes between two adjacent circuits.

- Load transfer schemes must account for the level of DER in both circuits to avoid problems such as over-voltages, etc.

- Devices, conductors, transformers, etc. involved in the scheme must have sufficient capacity to carry the transferred circuit load
- “Hidden” load resulting from distributed generation must be accounted for in system models to facilitate load transfer schemes
- A load flow analysis with various scenarios should be utilized to ensure that there is sufficient capacity in the system to accommodate transferred load
- Proper protection coordination and programming of protective devices with preset settings is encouraged so that devices operate as intended, even during contingency scenarios
- The use of automatic load transfer schemes is encouraged for improved reliability as a result of shorter outage durations; manual load transfer schemes take longer to enact

6 CONCLUSIONS

A detailed and thorough analysis of each circuit provides a better understanding of the feasibility of preliminary deployment of smart devices across the PNM distribution system. The diversity of load, generation, and circuit topologies across the PNM system necessitate a case-by-case power flow and protection analysis to ensure that devices can be deployed.

These general guidelines should only be used along with an extensive load flow study as well a detailed protective coordination. This necessitates that the Synergi model be verified on a circuit-by-circuit basis and finally as a whole. It also requires the protective software to be aligned with the planning software and needs processes in place to ensure continuous update of both models.

7 REFERENCES

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BURNS McDONNELL

CREATE AMAZING.

PNM EXHIBIT OBW-3
ESTIMATED DISTRIBUITON GRID MOD COSTS

DISTRIBUTION SYSTEM CAPITAL CLEARINGS

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
ADMS TOTAL	**$ -**	**$ -**	**$ -**	**$ 7,572,492**	**$ -**	**$ 15,400,258**
ADMS - DERMS	$ -	$ -	$ -	$ -	$ -	$ 6,320,913
ADMS - FLISR	$ -	$ -	$ -	$ -	$ -	$ 6,320,913
ADMS - IVVC	$ -	$ -	$ -	$ 6,216,137	$ -	$ -
ADMS Expansion - DERMS System Integration	$ -	$ -	$ -	$ -	$ -	$ 1,379,217
ADMS Expansion - FLISR System Integration	$ -	$ -	$ -	$ -	$ -	$ 1,379,217
ADMS Expansion - IVVC System Integration	$ -	$ -	$ -	$ 1,356,355	$ -	$ -
DISTRIBUTION AUTOMATION TOTAL	**$ -**	**$ 11,968,345**	**$ 16,150,848**	**$ 16,620,468**	**$ 17,661,467**	**$ 17,929,861**
Cap Bk & LTC Controls	$ -	$ -	$ 3,848,205	$ 3,960,099	$ 4,208,134	$ 4,272,084
Distribution Automation Intelligent Switches (Reclosers)	$ -	$ 10,843,694	$ 11,146,579	$ 11,470,689	$ 12,189,139	$ 12,374,372
Distribution Automation Intelligent Switches (Single Phse Reclosers / Smart Fuses)	$ -	$ 1,028,253	$ 1,056,974	$ 1,087,707	$ 1,155,834	$ 1,173,399
FCIs	$ -	$ 96,399	$ 99,091	$ 101,973	$ 108,359	$ 110,006
DISTRIBUITON PLANNING & ENGINEERING TOTAL	**$ -**	**$ -**	**$ 1,386,084**	**$ 7,459,364**	**$ -**	**$ -**
Dist Planning/Interconnection Forecast Tools	$ -	$ -	$ -	$ 7,459,364	$ -	$ -
Dist Planning/Interconnection Study Tools - Additional Synergi modules	$ -	$ -	$ 174,208	$ -	$ -	$ -
Interconnection Mangement systems	$ -	$ -	$ 1,211,876	$ -	$ -	$ -
TOTAL	**$ -**	**$ 11,968,345**	**$ 17,536,932**	**$ 31,652,324**	**$ 17,661,467**	**$ 33,330,119**
				GRAND TOTAL		**$ 112,149,187**

Note: Clearings are loaded with AFUDC, Project Management PMO Labor, Stores & Purchasing Loads (if applicable) and Labor loads (if applicable). Additionally, clearings include an 8% contingency

PNM EXHIBIT OBW-3
ESTIMATED DISTRIBUITON GRID MOD COSTS

DISTRIBUTION SYSTEM O&M

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
ADMS	**$ 819,333**	**$ 333,333**	**$ 833,333**	**$ 858,333**	**$ 1,884,583**	**$ 1,962,146**
ADMS - DERMS Annual Software Maintenance Fees	$ -	$ -	$ -	$ -	$ 500,000	$ 525,000
ADMS - FLISR Annual Software Maintenance Fees	$ -	$ -	$ -	$ -	$ 500,000	$ 525,000
ADMS - IVVC Annual Software Maintenance Fees	$ -	$ -	$ 500,000	$ 525,000	$ 551,250	$ 578,813
ADMS (FLISR/IVVC/DERMS) Business Process Change Management	$ 333,333	$ 333,333	$ 333,333	$ 333,333	$ 333,333	$ 333,333
O&M Labor, Professional Services for pre-work (business requirements)	$ 486,000	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION AUTOMATION TOTAL	**$ 9,750**	**$ 618,471**	**$ 741,521**	**$ 893,465**	**$ 1,082,979**	**$ 1,324,568**
Distribution Automation Annual Employee Expenses (flat)	$ 9,750	$ 9,750	$ 9,750	$ 9,750	$ 9,750	$ 9,750
Distribution Automation Employees		$ 608,721	$ 731,771	$ 883,715	$ 1,073,229	$ 1,314,818
DISTRIBUITON PLANNING & ENGINEERING TOTAL	**$ 382,007**	**$ 620,905**	**$ 645,223**	**$ 670,536**	**$ 696,885**	**$ 724,313**
Dist Planning/Interconnection Forecast Tools license	$ -	$ 200,000	$ 206,000	$ 212,180	$ 218,545	$ 225,102
Synergi License for Electric Load Flow Core License	$ -	$ 15,000	$ 15,450	$ 15,914	$ 16,391	$ 16,883
Synergi License for Protection License	$ -	$ 7,000	$ 7,210	$ 7,426	$ 7,649	$ 7,879
Preliminary Field Distribution Engineering Employees	$ 375,507	$ 392,405	$ 410,063	$ 428,516	$ 447,799	$ 467,950
Preliminary Field Distribution Engineering Annual Employee Expenses (flat)	$ 6,500	$ 6,500	$ 6,500	$ 6,500	$ 6,500	$ 6,500
TOTAL	**$ 1,211,090**	**$ 1,572,709**	**$ 2,220,077**	**$ 2,422,334**	**$ 3,664,447**	**$ 4,011,027**
					GRAND TOTAL	**$ 15,101,685**

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

SELF AFFIRMATION

OMNI WARNER, Director, Distribution Engineering, Public Service Company of New Mexico, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing **Direct Testimony of Omni Warner** and it is true and accurate based on my own personal knowledge and belief.

DATED this 3rd day of October, 2022.

_/s/Omni Warner_________
OMNI WARNER

GCG # 529848

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	))))))))	**Case No. 22-00058-UT**

DIRECT TESTIMONY

OF

JONATHAN C. HAWKINS

October 3, 2022

NMPRC CASE NO. 22-00058-UT
INDEX TO THE DIRECT TESTIMONY OF
JONATHAN C. HAWKINS

WITNESS FOR
PUBLIC SERVICE PNM OF NEW MEXICO

PNM Exhibit JCH-1	Resume
PNM Exhibit JCH-2	AMI RFP
PNM Exhibit JCH-3	Itron Pricing Sheet

Self-Verification

DIRECT TESTIMONY
OF JONATHAN C. HAWKINS
NMPRC CASE NO. 22-00058-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Jonathan Hawkins. I am the Associate Director of Innovation and Communications for Public Service Company of New Mexico ("PNM"). My address is 2401 Aztec Rd, Albuquerque, New Mexico 87107.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS ASSOCIATE DIRECTOR OF INNOVATION AND COMMUNICATION.

A. I am responsible for providing research and development of new technologies and proposing business applications for emerging technologies to support PNM's business objectives. I am also responsible for PNM's telecommunications and network systems.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I describe the advanced metering infrastructure ("AMI") meters chosen for PNM deployment, as well as the capabilities of these meters. I also describe various information and communications technology that must be deployed in conjunction with the AMI meters, as well as the cybersecurity measures PNM proposes to implement with its grid modernization projects. I also discuss the protection and management of customer data associated with the grid modernization deployment. I support the selection of the AMI vendor, integration of AMI technology into PNM's existing systems, and health and safety concerns over AMI meters. Finally, I support PNM's request to recover capital investment and operations and maintenance ("O&M") costs for the grid modernization components discussed in my testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF THE INFORMATION AND COMMUNICATION TECHNOLOGY COMPONENTS OF PNM'S PROPOSED GRID MODERNIZATION

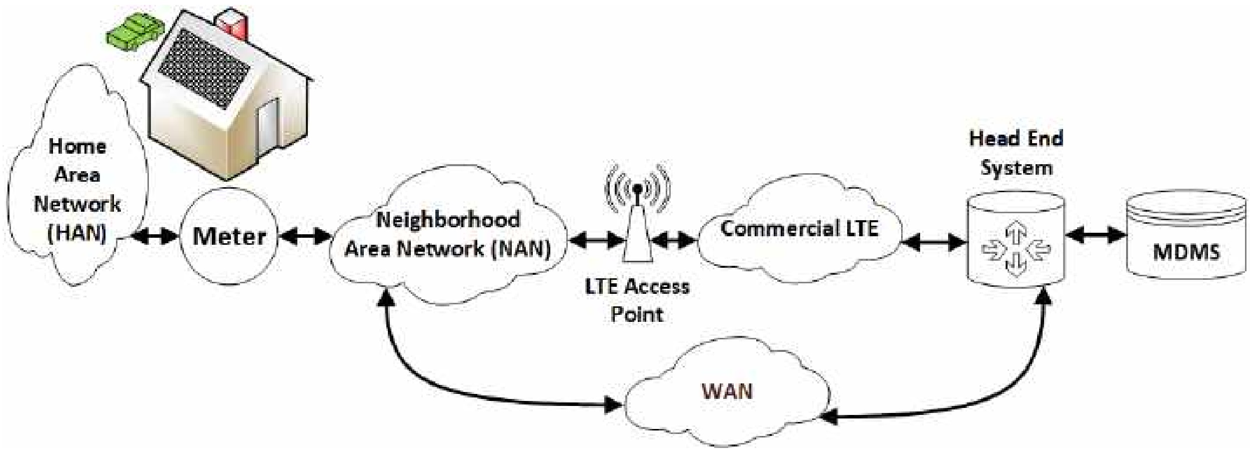
A. AMI is at the center of the information and communication technology grid investments PNM proposes. PNM's proposed AMI solution is comprised of:

- advanced meters;
- a standards-based wireless mesh neighborhood area network ("NAN") that uses cellular enabled access points and wide area network ("WAN") telecommunication pathways to a head-end system; and
- a meter data management system ("MDMS") to store and manage the meter data and interface with other systems, such as the PNM customer information system ("CIS," referred to as "Banner") to generate customer bills.

The information and communication technology software components for AMI (including the MDMS, the WAN, and the AMI wireless mesh NAN) interact with various data collection systems and system integrations. Each of these also require cybersecurity measures as well. PNM Figure JCH-1 below provides a graphical representation of the interactions between the AMI system and the relevant information and communications technologies.

PNM Figure JCH-1

Components of the PNM AMI System



I discuss each of the information technology ("IT")-related investments and their role in PNM's broader grid modification efforts below. An overview of how the information and communication technology components fit within the overall design for grid modernization is also described in the Guide for PNM's Grid Modernization Implementation ("Guide"), attached to the Direct Testimony of Laura E. Sanchez as PNM Exhibit LES-2.

II. PNM'S PROPOSED AMI SYSTEMS AND CAPABILITIES

Q. PLEASE DESCRIBE THE AMI METERS THAT PNM PLANS TO DEPLOY AS PART OF THE APPROVALS REQUESTED IN THIS APPLICATION.

A. PNM selected a fifth-generation smart meter with capabilities that have advanced significantly from the first-generation AMI meters deployed in California starting around 2008. This new generation meter includes:

- a remote disconnect and reconnect switch, service status (*i.e.*, power on/part-on/off);
- outage alerts and outage restoration notifications;
- voltage monitoring;
- tamper and theft detection;
- remote firmware and programming updates via the cyber secure network;
- ability to measure sub-second data;
- grid edge computing for analysis of data directly on the meter; and
- direct customer access via a home area network ("HAN") using the IEEE 2030.5 protocol.

A smart meter keeps track of how much energy is pushed through the meter and consumed by a customer, on a continuous basis. The interval data capabilities include measured, received and net kilowatt-hour ("kWh"), volt-ampere-hour ("VAh") and volt-ampere-reactive-hour ("VARh"), instrumentation profile for maximum, average, and minimum current for each phase of the meter, and voltage profile data. This data can: 1) give customers information to help manage their energy costs and make decisions about rate options as described in the testimony of PNM witnesses' Cervantes and Chan; and 2) provide power measurement and sensing capabilities to enhance PNM's visibility on distribution circuit conditions all the way to the customer.

Q. PLEASE DESCRIBE THE ENERGY USAGE DATA AMI METERS WILL COLLECT AND TRANSMIT TO PNM.

A. At this time, PNM is considering a 15-minute interval as the default meter data interval for most customers. Meters for customers with distributed energy resources ("DERs") (*e.g.*, solar, EV, demand response) would have an increased five-minute intervals resolution to provide additional energy profile and higher resolution data for PNM to assess power quality, hosting capacity, and interconnection requirements. The meter interval can be remotely updated from 15 minutes to five minutes when a customer installs DER or enrolls in a DER program. Customers can also authorize their DER aggregator or service provider to access their individual customer data through the customer energy management platform (*see* PNM witness Cervantes' testimony for more detail on the platform).

Meter data information will be transmitted to PNM every four hours to ensure meter reads are properly received and verified daily. The transmitted meter data will also be uploaded to the customer energy management platform to provide customers with the previous day's usage information and related monthly billing estimates and alerts, as discussed by PNM witness Cervantes. Additionally, individual meters can be read anytime on-request. For example, a real-time read can be made while a PNM contact center representative assists a customer.

Q. WHAT OTHER INFORMATION WILL THE AMI METER COLLECT AND TRANSMIT TO PNM?

A. AMI meters will collect and transmit the following information to PNM:

- <u>Outage Detection and Restoration</u>: The AMI meters can detect the loss and restoration of electric power, and transmit this information to PNM's outage management system, augmenting the traditional outage notifications provided by customer calls and Supervisory Control and Data Acquisition ("SCADA") systems notification. This will assist PNM operators in identifying outages more quickly and with more complete data. This is particularly crucial during storm restoration as it enables PNM to ensure power is restored for all affected customers after completing repairs.
- <u>Service Voltage:</u> The AMI meters can provide information to support customer power quality inquiries and historical data for distribution planners to support hosting capacity analysis and longer-term planning analyses. The voltage data can be recorded as part of the interval data set and voltage sag and swell notifications can be sent in real-time. The voltage notifications from the meters can be leveraged for the integrated Volt-Var control system as discussed in Mr. Warner's testimony.

Q. DO THE SELECTED AMI METERS HAVE SELF-DIAGNOSTIC CAPABILITIES TO PNM?

A. Yes, the selected AMI meters have the capability to perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module.

Q. HOW DOES THE METER COMMUNICATE DATA TO PNM?

A. The meter communicates through a wireless mesh NAN. The meter uses the mesh network to relay data until it reaches a cellular access point or the PNM WAN to communicate with PNM's head-end system, which then sends the meter data to the MDMS and other systems as needed (*e.g.*, the PNM's outage management system and CIS billing system). Additionally, some AMI meters may have a meter socket access point that PNM can use in locations where distribution infrastructure is underground and an access point cannot be mounted on a pole or where the mesh network is not viable because customers are geographically dispersed. The NAN and associated systems are discussed in more detail in Section IV below.

The meter communications enable:

- Transmission and receipt of the measurements, alerts, and events performed by the meter to PNM systems (*e.g.*, MDMS, outage management system, distribution management system);
- Meter configuration to measure specific metrology or power quality parameters or time-of-day intervals and data recording intervals;

- Remote upgrades for meter firmware and cybersecurity; and
- Commands to remote connect/disconnect service and communicate status.

Q. PLEASE EXPLAIN HOW PNM WILL DEPLOY AMI SUPPORTING SOFTWARE AND ASSOCIATED COMMUNICATIONS TECHNOLOGY.

A. PNM witness Eric Morgan details AMI meter deployment. PNM's deployment for supporting software and associated communications technology will take place over approximately three-and-a-half years. During that time, PNM will implement and integrate systems, deploy and implement the NAN, and deploy AMI meters. The meter head-end, MDMS and NAN deployment will be the first components installed and integrated during the deployment period. Advanced meters will be deployed after the NAN and software systems are enabled so that those systems are ready to communicate with the advanced meters. The deployment for the head-end and MDMS is expected to be completed in approximately 11 months and PNM expects to conduct detailed technical planning for systems architecture and integration for approximately six months prior to starting the head-end and MDMS implementation. After the MDMS is integrated and providing billing determinants to the CIS billing system, advanced meters that are confirmed to be communicating with the head-end and MDMS can be "cut over" to provide billing data to the CIS billing system. After the customer energy management platform is integrated with the MDMS or data historian,[1] the AMI meters will be able to communicate with the customer energy management platform, providing critical data to PNM's customers.

Q. WILL THE AMI METERS HAVE THE ABILITY TO COMMUNICATE WITH CUSTOMERS' DEVICES?

A. Yes. This latest generation meter can allow customers to connect the meter to their Wi-Fi network like other connected devices at their home or office. An interested customer can use the Wi-Fi connection to communicate with intelligent devices (*i.e.*, smart thermostats and building automation) or communicate with DER, including advanced inverters and electric vehicles. This Wi-Fi connectivity is new, and the specifics for how interested customers will connect the AMI meter to their Wi-Fi router and which customer devices will utilize the meter data are evolving. However, this capability is a significant step forward from the HAN solution included with previous generations of AMI meters.

[1] The data historian is described below.

Q. WILL PNM NEED TIME TO SET UP THE PROCESSES NEEDED TO ALLOW CUSTOMERS TO CONNECT THEIR WI-FI DEVICES TO THE AMI METERS?

A. Yes, in part because the HAN Wi-Fi capability is a new function in the latest generation of AMI meters that have just become commercially available. As such, connecting the advanced meter to the customer's Wi-Fi router and network has not yet been widely deployed in the industry. There are several technical and service support considerations to address before making this capability available to ensure reliable and secure connectivity between the meter and a customer's home or business Wi-Fi network. Also, PNM will need to develop a customer program to effectively enable this functionality for a seamless customer experience that includes information on how to initiate the connection, an online self-help guide, and call center support. This will also involve training PNM personnel to assist customers in accessing this capability, as well as trouble shooting issues that may arise, as is standard practice for any consumer service.

Q. DOES THE AMI METER HAVE REMOTE DISCONNECT/RECONNECT SWITCHING CAPABILITY?

A. Yes. The internal service switch has the ability to remotely connect and disconnect customers' electric service by PNM's customer service representatives via the integration of customer care applications with the AMI system. This capability will improve the move-in and move-out process for customers and will significantly decrease the amount of time to perform the tasks of disconnecting and reconnecting meters.

Q. WHAT IS PNM'S PROPOSED USEFUL LIFE FOR THE AMI METERS?

A. PNM proposes a 20-year useful life for the AMI meters, which translates to a depreciation rate of 5%, as explained in the testimony of PNM witness Kyle Sanders. The 20-year useful life is consistent with an informal Edison Electric Institute ("EEI") utility survey and the meter vendor recommendation. The EEI survey polled nine utilities and found an AMI meter average useful life of approximately 17 years, with some utilities using a 20-year useful life for depreciation purposes. The useful life as tested by the meter vendor is also expected to be 20 years. With that information, PNM proposes to use a 20-year useful life for the AMI meters.

III. INTEGRATION AND IMPLEMENTATION OF INFORMATION SYSTEMS

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR DIRECT TESTIMONY?

A. The grid modernization technologies PNM proposes to implement in this application will require information and communications systems upgrades for full integration. In this section of my testimony, I describe the grid modernization information and communications systems and the required integration. This section also details the information, security, and communications integrations necessary to implement the AMI software systems, including the MDMS and head end system, the customer energy management platform, the operational service bus, and data historian.

Q. WHY DOES AMI REQUIRE INTEGRATION WITH OTHER SOFTWARE SYSTEMS?

A. AMI is a system of meters and networks that provides two-way communication between the meter and the utility's control center, allowing collection of data to benefit both the utility and customers. Once that data is communicated to the control center, it must be integrated into other software applications to realize benefits. For example, outage notifications from the advanced meters need to be routed to the existing outage management system ("OMS") to alert the utility of outages more quickly or provide information on power quality issues at various points in the network. The AMI meter data will also be presented in the customer energy management platform to provide intra-month data customers can securely access to better understand and manage their energy usage.

Q. PLEASE DESCRIBE THE AMI SYSTEM SOFTWARE AND DATA MANAGEMENT COMPONENTS OF PNM'S GRID MODERNIZATION PLAN.

A. The AMI system software and data management components of PNM's grid modification application consists of the following:

- AMI head-end system tracks meter connectivity, and operational performance of the AMI meter and the AMI communications network. The head-end system functionality schedules automatic meter data collection, monitors event notification (*e.g.*, power outage, tampering), and tracks meter and network operational performance. The AMI head-end system also gives PNM secure access to meters and network access points for configuration, software updates and ad-hoc requests.
- MDMS is a software system with primary functions including validation, estimation, and editing ("VEE") of meter data, data repository, and organizing the meter data to share it with other applications, including customer billing, outage management, and forecasting and planning tools. The selected MDMS includes integrated applications for analytics and interfaces with PNM's CIS billing system. PNM's MDMS will include specific provisions for both cybersecurity and data privacy as discussed below.
- Customer Energy Management Platform is a web portal accessible by customers via personal computer and/or smart tablet and smartphone application. PNM's customer energy management platform will provide customers access to their usage data and other information and enable customer data access via Green Button Connect My Data ("Green Button") for downloading large quantities of data while also safeguarding the data via strong privacy protections and cybersecurity measures.

- PNM Data Historian is an electronic repository of data collected from one or more disparate sources and integrated to support business or operational analysis. In following with utility best practice, PNM is planning to implement an electronic data historian to support the AMI and ADMS. This system will be integrated with other applications such as Synergi to utilize historic data in operating and modeling the distribution system. The AMI data historian can also provide the data needed for the customer energy management platform.

Q. PLEASE DESCRIBE THE GRID PLANNING AND OPERATIONAL SOFTWARE COMPONENTS OF PNM'S GRID MODERNIZATION PLAN.

A. The grid planning and operational software components of PNM's grid modification application consist of the following:

- AMI Integration with ADMS – An Advanced Distribution Management System ("ADMS") is a software platform that can integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. The ADMS utilizes the sensing and measurement capabilities of substation automation SCADA, distribution automation field devices, and advanced metering to enhance the monitoring, control and automation capabilities for distribution grid operations and management. PNM's existing ACS Prism distribution management system and OMS will be expanded and further integrated into an ADMS to provide the services described below. PNM witness Omni Warner presents detailed information regarding PNM's proposed ADMS expansion.

- Outage Management – AMI meters will serve as sensors throughout the grid to alert PNM's Operations Centers of anomalies on the grid such as outages and/or power quality issues. As such, PNM will need to integrate the AMI head-end system with the existing OMS to receive AMI outage notifications, dispatch field crews to restore service to affected customers, and verify outage restoration.
- Voltage Management – AMI meters can provide PNM voltage swell and sag notifications. As part of integrated Volt-Var management, PNM will integrate those voltage notifications into the ADMS to support distribution automation devices by providing feedback on voltage levels after grid adjustments.
- Distributed Energy Resource Management – AMI meter data can support operation of the grid with customer DER management and DER programs. The AMI data to support this will be integrated into a distributed energy resource management system ("DERMS"). The DERMS will also interface with larger DERs *(e.g.*, community solar and substation battery storage).

- <u>Operational Service Bus</u> – System integration software technology will connect applications and services, support service composition and workflow management, and provide asynchronous data and state transfer among data sources, applications, and processing or transaction services. The operational service bus will facilitate data exchange between the systems described herein.

Q. PLEASE DESCRIBE PNM'S PLAN FOR INSTALLING THE INFORMATION AND COMMUNICATIONS TECHNOLOGY NECESSARY FOR AMI DEPLOYMENT.

A. After an approximately six-month detailed technical planning period, PNM will begin installing and integrating the AMI head-end system and MDMS to the existing CIS billing system, PNM's Geographic Information System ("GIS"), the OMS and the data historian utilizing the operational service bus software technology. PNM will then validate that these systems can properly retrieve information from the meters through the NAN mesh network. The deployment for the head-end and MDMS is expected to be completed in approximately 11 months.

IV. TELECOMMUNICATION NETWORKS AND IMPLEMENTATION

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR DIRECT TESTIMONY?

A. In this section of my testimony, I describe the telecommunication network that will provide two-way connectivity between the PNM control center, distribution field devices and the AMI meters.

Q. PLEASE DESCRIBE THE TELECOMMUNICATION INFRASTRUCTURE NECESSARY TO SUPPORT AMI DEPLOYMENT.

A. A telecommunication network is required to support deployment of AMI meters and distribution automation field devices and facilitate the operation of future advanced grid applications. In the initial six-year implementation period, PNM plans to deploy a neighborhood area network, or NAN, to serve as the telecommunication network supporting AMI deployment and distribution automation devices. The networks being deployed are a set of hierarchical networks starting with the PNM WAN that will send data directly back to PNM software systems, and the wireless mesh NAN, which will bring those communications further into neighborhoods to devices such as the new AMI meters. The AMI wireless mesh NAN will communicate with the head-end system either through cellular access points or through direct connection to the WAN where possible. The AMI system cannot function without these enabling telecommunication devices.

PNM anticipates the NAN may not support future needs for bandwidth (speed) and latency (timeliness) as additional distribution automation devices are deployed. Therefore, PNM identified the potential need for a high-speed Field Area Network ("FAN") in the second half of its 11-year grid modernization deployment strategy.

Q. PLEASE PROVIDE AN OVERVIEW OF PNM'S NAN AND HOW THE NAN WILL COMMUNICATE TO OTHER DEVICES?

A. The NAN will be a resilient wireless mesh communications network providing two-way connectivity for AMI as well as existing and new distribution field devices. With a mesh network, each device on the network can relay data until it reaches an access point or the WAN. The advanced meter communications will utilize cellular or direct WAN connected access points to communicate with the AMI head-end system. The distribution automation communications will utilize the WAN to communicate with PNM operational systems like the ADMS.

Q. HOW WILL PNM IMPLEMENT AND INSTALL THE NAN?

A. To implement the NAN, PNM must (1) design the network systems and cybersecurity, (2) configure the software and hardware components of the NAN in the back office, (3) install the NAN devices (i.e., primarily cellular or direct WAN connected access points and repeaters), (4) install the NAN Distribution Automation ("DA") communication bridges and NAN Network Interface Cards ("NIC") on the distribution automation devices, and (5) integrate the NAN with the WAN for distribution automation telecommunications support.

The wireless mesh NAN repeaters and cellular access points will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device. In areas where PNM has underground service, arrangements will be made to mount the devices on streetlights or other structures with appropriate height. In the alternative, meters can be fitted with a collar device that provides cellular access point communication rather than a pole mounted access point.

Q. PLEASE PROVIDE AN OVERVIEW OF PNM'S PROPOSED GRID MODERNIZATION IMPROVEMENTS TO THE WAN.

A. PNM currently utilizes both microwave and fiber optic communications utilizing Synchronous Optical Network ("SONET") as part of its WAN. However, the WAN configuration needs updating to modernize and increase bandwidth (telecommunications speed) and reduce latency (telecommunications delay) to support grid modernization investments. Three investments have been identified to update the WAN:

1) Multiprotocol label switching ("MPLS") transport conversion: MPLS will enable the routing capabilities needed to support modern networking capabilities for distribution automation.
2) Dense Wavelength Division Multiplexing ("DWDM") conversion: DWDM will enable the existing and future fiber optic cable to support both SONET and networked substation and distribution automation devices.
3) WAN Microwave system modernization: The existing microwave system bandwidth supports the SONET serial communication technology currently used in PNM's system. As the systems are moved to MPLS transport, modernization of the microwave system will be required to support the

higher bandwidth requirements. In addition, an evaluation will be done on all communication in the 6 GHz spectrum for possible conversion to the 11 GHz spectrum to mitigate interference caused by new Wi-Fi version 6e consumer equipment.

V. CYBERSECURITY AND THE PROTECTION OF CUSTOMER DATA

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR DIRECT TESTIMONY?

A. In this section of my testimony, I address how grid modernization deployment complies with applicable cybersecurity regulations and PNM's cybersecurity policies. I also detail the cybersecurity measures PNM proposes to implement with its grid modernization program.

Q. DOES THE GRID MODERNIZATION STATUTE ADDRESS CYBERSECURITY AND CUSTOMER DATA PROTECTION?

A. Yes, in considering applications for approval of grid modernization projects, the statute directs the Commission to consider whether proposed projects are reasonably expected to improve reliability, resilience, and security. The statute defines "grid modernization" to include "technologies or services that are designed to modernize the electric system by enhancing … grid security against cyber and physical threats."[2]

Q. PLEASE DESCRIBE PNM'S CYBERSECURITY POLICIES.

A. PNM maintains a comprehensive cybersecurity program to address the risks associated with malicious software attacks. The cybersecurity program is designed to protect PNM computers, servers, business applications and data, and high value networks from unauthorized access and control from both external and internal threats. The cybersecurity threat landscape constantly evolves and expands, and it is critical to continuously improve PNM's defense posture through investments in technology, improvements in cybersecurity processes, and collaboration with law enforcement, regulatory and industry resources.

PNM's guiding security philosophy is to simplify, secure, and standardize where possible in order to provide a reliable, resilient, and redundant environment to mitigate risk across the enterprise and define PNM's security strategy.

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[2] NMSA 1978, Sec. 62-8-13(F); *see also* Sec. 13(F)(7), which specifically references "cybersecurity measures" as a specific technology mean to be addressed by grid modernization.

PNM uses a risk-based process aligned with the National Institute of Standards and Technology ("NIST") Cybersecurity Framework ("CSF") Core Functions to manage security threats. The CSF defines the five core functions as follows:

- Identify – Identify threats and inform the enterprise as a key part of the end-to-end intelligence program.
- Protect – Stop would-be intruders from infiltrating and entering protected systems.
- Detect – Effectively detect and deter cyber threats via monitoring tools and other analytics.
- Respond – Assess, contain, and mitigate damages from compromising events by utilizing tools, a trained workforce, and other resources.
- Recover – Return systems to normal and understand how to protect and assess vulnerabilities in the system. All-hazards based recovery capabilities apply to all threats.[3]

By applying this organizing foundation, PNM positions itself to protect its networks and assets based upon the risk to the business and customers.

[3] https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf

PNM has defined and implemented the CSF using industry standards and best practices.[4] These objectives support PNM's goal to provide reliable electric service to customers. Computer security will remain a major concern for PNM for both the short and long term, as malicious software and intrusions continue to become more sophisticated. The actors are changing and increasingly have the skills to employ stealth techniques over time that attempt to evade and disable current detection mechanisms. As such, PNM continuously assesses its cybersecurity program to help evaluate, prioritize and improve security capabilities to protect against cybersecurity threats.

Q. WHAT CYBERSECURITY MEASURES DOES PNM PROPOSE TO IMPLEMENT IN ITS GRID MODERNIZATION PLAN?

A. PNM has comprehensive policies and processes that will be followed during procurement, design, and operation of any cyber asset associated with grid modernization. Applicable processes include the following:

- Identifying, prioritizing, and assessing supplier's and other third-party providers'[5] systems, components, and services using a supply chain security risk assessment process;

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[4] *See* International Standardization Organization ("ISO") Standard 27002, COBIT 5, and the NIST 800 Series as reference models and industry best practices.
[5] Other third parties include the parties that work with PNM's existing suppliers.

- Protecting network integrity (*e.g.*, network segregation, network segmentation);
- Authenticating users, devices, and other assets commensurate with the risk of the transaction (*e.g.*, individuals' security and privacy risks and other organizational risks) or applying mitigating controls;
- Protecting data-at-rest commensurate with its classification;
- Protecting data-in-transit commensurate with its classification;
- Verifying software, drivers, firmware, and information integrity with integrity checking mechanisms;
- Implementing configuration change control processes;
- Protecting, monitoring, and restricting access to communications and control networks;
- Ensuring no device will be connected to the network without authority to operate and an appropriate set of protective software;
- Establishing and monitoring a baseline of network and system operations and configuration;[6] and;
- Assessing suppliers and third-party partners to evaluate the security of their programs prior to contractual obligation.

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[6] A baseline of normal user activity is established and monitored. Personnel and account activity are monitored to detect potential security events

These processes will help PNM implement a risk-based approach to protecting its grid modernization-related cyber assets.

Q. PLEASE DESCRIBE THE CYBERSECURITY INVESTMENTS PNM PROPOSES TO ALIGN ITS GRID MODERNIZATION PLAN WITH THE PROCESSES OUTLINED ABOVE.

A. To address the expanded networks needed to communicate with the AMI and distribution automation devices, as well as the types of devices used within the distribution system, PNM will require additional cybersecurity controls. PNM will invest in:

1) A cybersecurity monitoring system specifically addressing industrial control systems devices that are used within the distribution system. This system will help identify, detect and respond to cybersecurity issues with these devices.

2) Additional firewalls to be used between networks to provide network access rules between various new networks. The firewalls will help protect and detect appropriate or inappropriate data traffic to allow or block, as appropriate, between networks.

3.) Network security monitoring and a Security Information and Events Management ("SIEM") system for the new operational networks. This system will monitor and serve as an alert system to identify, detect, and respond to cybersecurity issues on the new networks.

4.) Software defined networking and network segmentation for the new networks.

These applications will allow PNM to separate networks virtually within a single physical network to control where data can traverse within the network and between networks.

Q. PLEASE DESCRIBE PNM'S PROPOSAL TO PROTECT THE CONFIDENTIALITY AND PRIVACY OF CUSTOMER INFORMATION WITH AMI?

A. To protect customer confidentiality, PNM is adopting the U.S. Department of Energy's DataGuard Energy Data Privacy Program ("DataGuard")[7] code of conduct to implement customer-facing technologies. The key tenets of the DataGuard code include:

- Consumer Notice and Awareness: Customers should be given prior notice about privacy-related policies and practices.
- Customer Choice and Consent: Customers should have a degree of control over access to their own customer data.
- Customer Data Access and Participation: Customers should have access to their own customer data and should have the ability to participate in its maintenance.

[7] https://www.smartgrid.gov/data_guard.html

- Integrity and Security: Customer data should be as accurate as reasonably possible and secured against unauthorized access.
- Self-Enforcement Management and Redress: Enforcement mechanisms should be in place to ensure compliance with the foregoing principles.

Since its launch in 2012, DataGuard has become an established industry best practice. PNM will use the DataGuard voluntary code of conduct within the policies, processes, and procedures that will need to be developed to govern and operate the new data systems associated with the AMI system.

In addition, PNM's customer-facing systems will conform to the U.S. National Institute of Standards and Technology's "Guide to Protecting the Confidentiality of Personally Identifiable Information" (Publication NIST SP 800-122).[8]

VI. VENDOR SELECTION FOR AMI METERS

Q. HAS PNM SELECTED AN AMI VENDOR AND AN AMI METER?

A. Yes, PNM selected Itron as the AMI system vendor to supply its newest Riva AMI meter.

[8] http://nvlpubs.nist.gov/nistpubs/Legacy/SP/nistspecialpublication800-122.pdf

Q. PLEASE PROVIDE AN OVERVIEW OF PNM'S VENDOR SELECTION AND IDENTIFICATION PROCESS.

A. The AMI RFP was issued to six potential vendors. I attach the AMI RFP to my testimony as PNM Exhibit JCH-2. PNM received three proposals and three vendors declined to submit proposals, citing a variety of reasons including technical differences between their products and the described approach and the quick turnaround time for the proposals. Although PNM described a preference for a standards-based mesh network to support AMI, the technical questionnaire did request descriptions of alternative technical approaches. One of the proposals received proposed a cellular LTE based solution and PNM conducted an interview to obtain a technical overview, but the proposal did not meet all criteria for providing an AMI solution. The remaining two proposals were both viable and were evaluated and scored based on commercial and technical evaluation criteria, as described below.

Q. HOW DID PNM GO ABOUT SOLICITING TECHNICAL DETAILS FROM VENDORS?

A. The RFP contained a technical questionnaire to solicit technical details and pricing for each vendor's AMI solution. The standard PNM Equipment Purchase Agreement ("Purchase Agreement") was provided to the vendors so they could propose redline edits and comments as a potential starting point for negotiations assuming a vendor was selected. One vendor relied on its existing and recently re-negotiated Master Sales Agreement ("MSA") with PNM, while the other vendor deferred from providing feedback on the Purchase Agreement and instead provided a copy of its standard master purchase, license and services agreement as an example of the product terms and conditions it typically provided.

Q. PLEASE EXPLAIN THE TECHNICAL EVALUATION PROCESS PNM EMPLOYED TO EVALUATE RFP REPONSES.

A. A team of 35 subject matter experts from across PNM were assigned different sections of the technical questionnaire to evaluate based on their area of expertise. The technical sections included:

1. Communications;
2. Metering Specifications;
3. Collector and Field Area Router, Gateway, and Repeater Specifications;
4. Home Area Network (HAN), Demand Response (DR) and Distributed Energy Resource (DER);
5. Network Management System (head-end) Requirements;
6. Meter Data Management System;
7. Training;
8. Project Management;
9. Quality Program; and
10. Industry Experience and other questions on topics, including legacy MV-90 metering support and transition, load research, meter data disaggregation, and customer energy portal.

Each team of internal subject matter experts evaluated the vendor responses and scored them. PNM aggregated the scores for the entire vendor response to identify the highest scoring response and validate the proposed vendor selection amongst the entire scoring team.

Q. PLEASE EXPLAIN HOW PNM SCORED THE COMMERCIAL AND TECHNICAL EVALUATIONS.

A. The commercial evaluation and the technical questionnaire for the AMI (except for the customer energy management platform) were scored on a scale from 1-5 where 5 = Exceeds PNM Expectations, 4 = Slightly Exceeds PNM Expectations, 3 = Meets PNM Expectations, 2 = Mostly Meets PNM Expectations, 1 = Barely Meets PNM Expectations, and 0 = Does not Meet PNM Expectations.

The customer energy management platform is proceeding down a separate procurement path as described in the Direct Testimony of PNM witness Cervantes, but the answers to the customer energy management platform questions provided additional insight for that procurement. Additionally, the meter data disaggregation section was added as a direct result of stakeholder input.

Q. HOW DID PNM FACTOR THE DIFFERENT EVALUATION CONSIDERATIONS?

A. There were three scoring factors for the RFP evaluation:

1. RFP and commercial terms and conditions ("T&Cs") compliance,

2. Technical solution, and
3. Solution cost and pricing.

10% evaluation weighting factor was assigned to RFP and commercial T&Cs compliance, a 60% valuation weighting factor was assigned to the technical solution evaluation, and a 30% weighting factor was assigned to the solution cost and pricing. In this instance, the chosen vendor had higher scoring for all three evaluation criteria, although the technical solution evaluation scoring was relatively close between the two competitive bidders.

Q. WHY DID PNM ASSIGN A GREATER WEIGHT TO THE TECHNICAL EVALUATION SCORES?

A. Though all scoring criteria is important, PNM assigned the greatest weight to the technical solution because PNM sought a robust technical solution that would yield the highest performance for customers while meeting the needs of today's and tomorrow's grid.

Q. WAS THE SELECTED VENDOR THE LOWEST COST RESPONSE?

A. Yes. Itron, the selected vendor, had the lowest overall cost for implementation and recurring costs over the next 10 years, thereby providing the best value for PNM's customers.

Q. WHAT IS THE STATUS OF VENDOR CONTRACT NEGOTIATIONS FOR THE AMI COMPONENT?

A. PNM has a signed Master Service Agreement and pricing with the vendor. Attached as PNM Exhibit JCH-3 is a pricing summary provided by Itron in response to PNM's RFP. Absent a change in circumstances, the pricing summary from Itron is indicative of the cost PNM will incur for the AMI system. PNM continues to negotiate contract terms and conditions specific to the PNM AMI project. PNM will make the contract available for review once it is finalized.

Q. PLEASE DESCRIBE THE CONTRACTS WITH THE SELECTED VENDORS.

A. The contract with Itron consists of an existing Master Sales Agreement with several attached Statements of Work covering individual components of the overall AMI project such as the MDMS, AMI meters/network/head-end system, maintenance and support, and managed services provided by Itron.

Q. HOW WILL THE CONTRACT BE MANAGED?

A. The contract will be managed by PNM's internal project management office during project initiation and deployment. During closure of the project, ongoing management and continued operation of the various systems will be assigned to the appropriate internal PNM groups. For example, ongoing contracts associated with metering components will likely be managed by PNM's Meter Department, while software applications will likely be managed by PNM's Business Technology Solutions department, which supports the company's IT assets.

Q. ARE YOU AWARE THAT SOME CUSTOMERS HAVE CONCERNS REGARDING THE HEALTH AND SAFETY ASPECTS OF AMI?

A. Yes, PNM is aware that some customers have concerns related to the electromagnetic field aspects of the AMI solution radio frequency ("RF") communications. However, the meters have an extremely low-level of RF exposure—well below the compliance requirements established by the Federal Communications Commission ("FCC") for safe operations. For example, household items like mobile phones, microwaves, and baby monitors emit more radio frequency energy than AMI meters. Also, the average AMI communication transmission time is only 60 seconds per day.

Q. DO THE AMI COMPONENTS SELECTED MEET FEDERAL AND INDUSTRY HEALTH AND SAFETY STANDARDS?

A. Yes. All of the AMI devices are third-party tested and certified to Underwriter Laboratory ("UL") standards and approved under FCC Part 15 Sub-part B and C requirements to operate in the industrial, scientific and medical ("ISM") radio band, which is unlicensed spectrum internationally reserved for ISM uses, such as AMI.

Q. WILL PNM BE ENGAGED IN ADDITIONAL RFP PROCESSES AS IT MOVES FORWARD WITH THE PLANNING AND IMPLEMENTATION OF ITS GRID MODERNIZATION?

A Yes. PNM expects to issue an RFP for systems integration between AMI and the existing PNM systems (*e.g.*, CIS billing system, distribution management system, OMS) in the fourth quarter of 2022. PNM witness Morgan discusses the proposed RFP for meter installation.

VII. GRID MODERNIZATION SOFTWARE, DATA MANAGEMENT AND SYSTEM INTEGRATION COSTS

Q. PLEASE PROVIDE THE PROPOSED GRID MODERNIZATION INFORMATION AND COMMUNICATION SYSTEM COSTS

A. The estimated capital costs for the proposed grid modernization projects discussed in my testimony are provided below. PNM Table JCH-1 represents capital investments for AMI, cybersecurity, data management, distribution automation and telecommunications during the initial six-year implementation plan period.

PNM Table JCH-1
Grid Modernizataion AMI, Information and Communications Capital Costs

Row Labels	Sum of Total Year 1	Sum of Total Year 2	Sum of Total Year 3	Sum of Total Year 4	Sum of Total Year 5	Sum of Total Year 6
Advanced Metering	$1,684,766	$39,583,299	$45,399,897	$39,469,093	$1,722,539	$0
Cybersecurity	$69,295	$4,062,099	$210,662	$210,473	$217,141	$0
Data Management & Architecture	$2,864,800	$1,578,605	$1,090,725	$1,089,748	$0	$0
Distribution Automation FAN	$4,152,671	$4,216,597	$0	$0	$0	$0
Telecommunications	$182,938	$7,881,382	$8,034,705	$8,070,838	$8,326,547	$8,198,063
Grand Total	**$8,954,470**	**$57,321,982**	**$54,735,989**	**$48,840,152**	**$10,266,227**	**$8,198,063**

The O&M costs for the proposed grid modernization projects discussed in my testimony are provided in PNM Table JCH-2 below.

PNM Table JCH-2
Grid Modernization AMI, Information, and Communications Recurring Costs

Row Labels	Sum of Year 1	Sum of Year 2	Sum of Year 3	Sum of Year 4	Sum of Year 5	Sum of Year 6
Advanced Metering	3,739,131	3,831,170	4,067,867	4,356,926	4,324,513	4,379,889
Cybersecurity	0	217,350	228,217	239,628	251,609	264,190
Data Management & Architecture	1,105,228	1,852,562	1,987,705	2,249,500	2,340,364	2,435,061
Telecommunications	383,371	400,268	765,378	799,173	834,490	871,395
Grand Total	**5,227,730**	**6,301,350**	**7,049,167**	**7,645,227**	**7,750,976**	**7,950,535**

The first-year recurring costs are expected to be spent in the areas shown in PNM Table JCH-3 below:

PNM Table JCH-3
Grid Modernization AMI, Information, and Communications Recurring Costs Year 1

Row Labels	Sum of 1
Labor AMI Database Administrator/Analyst	$165,107
Labor AMI Radio Frequency (RF) Technician	$165,107
AMI System Administrator	$165,107
AMI System Software Mainteance and Software as a Service Costs	$3,243,811
Labor 5 Positions in Operations Technology/IT/Data/Cybersecurity Architecture & Engineering	$1,105,229
Telecom Operations & Management Employees	$382,007
NAN Network O&M Annual Software Maintenance Fees	$1,364
Grand Total	$5,227,731

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION:

UNIVERSITY of NEW MEXICO, Albuquerque, New Mexico
Bachelor of Science in Electrical Engineering – December, 1994

New Mexico Engineering Intern Certification (Certificate Number 6210)

EXPERIENCE:

Mar. 2010 – present

PNM Resources (PNMR). Albuquerque, NM. *Associate Director, Innovation and Communication*

Manage a team that monitors technology trends and provides cross functional technical support for emerging technologies in energy generation and delivery, including areas such as integration of renewable energy systems, energy storage, and smart grid technologies

Demonstrated history of employee development with employees earning advanced degrees, three Innovation Awards as presented by PNMR Board of Directors, and promotions internal and external to PNMR

Managed multi million dollar operational and capital budgets associated with multiple departments

Led technical development and delivery of foundational and transformational technology projects at PNMR.   Examples of projects include energy storage technology, microgird integration, electric vehicle infrastructure development, advanced metering, secure substation remote access, physical security, and various projects to facilitate NERC Critical Infrastructure Protection (CIP) compliance

Led and participated in technical aspects of energy storage and microgrid projects earning national or international recognition including finalist for Platts Global Energy Award in Sustainable Innovation, runner up for POWERGRID International Renewable/Grid Integration Project of the Year, runner up for International Energy Agency (IEA) Implementing Agreement for a Co-operative Programme on Smart Grids (ISGAN) award, personally named 50 Smart Grid Pioneers by Smart Grid Today, and earned a Robert Price Innovation Award awarded by the PNMR Board of Directors

Participation as a technical expert for PNM in the PRC led revision of the New Mexico Interconnection Manual, the State of New Mexico's Grid Modernization Roadmapping effort and Energy Storage working group

Developed or participated in development of multiple applications for government grants with many securing funding, including a $2.3M grant for a renewables with energy storage project

Co-developer of the cyber security plan to comply with DOE requirements for an energy storage project

Authored or or co-authored twelve peer-reviewed technical publications in magazines or scientific journals on energy storage and electic vehicle integration (publication list available on request)

Earned U.S Patent (U.S. Patent Number 9,692,234) “Systems and Methods for Distributing Power Using Photovoltaic Resources and a Shifting Battery System”

Invited reviewer for Department of Energy for the DOE Sunshot Program, National Science Foundation (NSF), and Small Business Innovation Research (SBIR)/Small Business Technology Transfer Research (STTR) for funding opportunities reviewing renewable energy and storage grant applications

Developed or participated in development of multiple applications for funding by the U.S Department of Energy and National Science Foundation. Multiple applications were chosen for funding where I led the projects both in terms of technical project activities as well as governmental compliance and reporting requirements

Collaboration with Japanese Government organization (NEDO) and Japanese vendors on smart grid projects in New Mexico

Led and facilitated use case workshops with multiple Japanese organizations to document and specify desired capabilities of the New Mexico smart grid projects done by NEDO. The use cases were published internationally, were promoted by NEDO as a key project success of the local micro grid project, and served as foundational use cases for both the IEEE P2030.7 working group efforts for micro grids as well as in the Smart Grid Interoperability Panel (SGIP) Micro grid Domain Expert Working Group

Member of external advisory board for a Sandia National Laboratories Grand Challenge project which won an R&D100 award as a innovative solar technology

Frequent public speaker at industry conferences and local requests on topics such as energy storage, renewable energy, utility industry technology trends, IT/OT convergence, energy storage control architecture, and electric network model management

Participation in and collaboration with multiple industry standards organizations, working groups, and research organizaitons such as IEEE, Smart Grid Interoperability Panel, Western Energy Institute, Edison Electric Institute, Rocky Mountain Institute, Santa Fe Instiitute, the Electric Power Reserarch Institute (EPRI), the State of New Mexico, multiple universities across the United States and national laboratories such as National Renewable Energy Laboratory (NREL), Idaho National Laboratory, Los Alamos National Laboratory and established a formal Cooperative Research and Development Agreement (CRADA) with Sandia National Laboratories

Manage the PNMR research and development contract with the Electric Power Research Institute (EPRI). Advisor to EPRI for programs on integration of distributed renewables, Enterprise Architecture, Cyber Security, Smart Grid Demonstration Project, Electrification Initiative, Energy Storage Integration Council (ESIC), Sector Council member for EPRI Information and Communication Technology, and former member of Research Advisory Committee (RAC)

Manage a team responsible for telecoommunications, fiber optic facilities, networking and cyber security activies including NERC Critcal Infrastructure Protection (CIP) compliance

Part of PNMR technology road mapping efforts serving various internal business needs including benchmarking other utility approaches

Involved in PNMR's Enterprise Risk Management program specifically addressing and providing strategic industry information on new technologies and effects to business transformation

Support Public Policy Organization for regulatory and policy needs and communication with respect to technology initiatives including support for internal and external Economic Development organizations.

Formerly PNMR's voting member to the Smart Grid Interoperability Panel (SGIP) and participant in multiple Domain Expert Working Groups (DEWGs) and Priority Action Plans (PAPs)

2002 – 2010

Public Service Company of New Mexico (PNM). Albuquerque, NM. *Manager, Electric Distribution Standards (Sept. 2002 to Mar. 2010), Manager Electric and Gas Standards and Technical Training (Sept. 2002 to Mar. 2004), Project Manager (Mar. 2002 – Sept. 2002)*

Managed a department that drove policies and was responsible for technical approval of all new materials, material changes and design standards used in building and maintaining electric distribution, gas distribution and gas transmission infrastructure. The department was also responsible for management of the Joint Use department responsible co-location of electric and communication infrastructure

Managed relationships with vendors and participated in contract negotiations on multi-million dollar, enterprise wide contracts for electric utility equipment

Led teams to analyze business processes using Root Cause Analysis, Lean, and Six Sigma techniques

Led teams to analyze best practices and potential synergies with regard to the acquisition and integration of a utility acquired by PNMR

Responsible for managing all technical training for gas field personnel (54 classes in the syllabus), material training for electric personnel, and the Distribution Engineering Mentorship Program

Responsible for implementation and administration of Natural Gas Operator Qualification program to meet auditable Department of Transportation (DOT) regulations

Project management related to construction and maintenance on electric distribution substations throughout the state including obtaining permits, materials, and scheduling crews

1997 - 2002

Sumitomo Sitix Silicon. Albuquerque, NM. *Senior Quality Engineer (2000-2002), Quality Engineer II (1998-2000), Quality Engineer I (1997-1998), Production Supervisor (1994-1997)*

Quality Engineer responsible for expansion, operation, and analysis of results obtained in the plant's semiconductor material characterization laboratory. Also, process owner for multiple sets of semiconductor metrology equipment and fabrication processes throughout the plant

Process designer for aspects of ISO 9002, QS 9000, and ISO 14001 processes and active participant in initial certification and follow up surveillance audits

Continuing education courses in advanced statistical process control and Design of Experiments

Managed a 6:00 PM to 6:00 AM production shift. Responsible for interviewing and hiring a staff of 16 Material Processors during facility start-up. Implemented employee development matrices and provided periodic performance appraisals. Responsible for coordinating resources to meet productivity and on-time delivery requirements. Also, served as Emergency Response Team Incident Commander

ORGANIZATIONS:

President of the Board of Directors for New Mexico Math, Engineering , Science Achievement (MESA) 2017, Board member since 2015.

Board of Directors for the New Mexico Engineering Foundation (2007-2013) – served as Vice President (two terms), President, and Past President (two terms).

Quality New Mexico Award Examiner auditing New Mexico companies against the Malcolm Baldrige National Quality Award criteria for 14 years. Seven of those years served as a team lead

Member of DNP3 Users Group and IEEE.

Current member of Advisory Board for the College of Electrical and Computer Engineering at the University of New Mexico

Current member of New Mexico's State Committee for DOE's Experimental Program to Stimulate competitive Research (EPSCoR)

Certified C Licensed Coach by U.S. Soccer and coach of youth club soccer teams

REQUEST FOR PROPOSAL

RFP #176-PNM2-2022

Advanced Metering Infrastructure (AMI) for Public Service Company of New Mexico’s (PNM’s) New Mexico service territory

Abstract:

PNM is issuing this Request For Proposal (RFP) in order to solicit proposals for Advanced Metering Infrastructure (AMI) for electric meters in its New Mexico service territory. This RFP seeks the greatest total value for AMI meters and associated equipment. Only bidders who return a completed response by July 8, 2022 – 1:00 PM Mountain Time will be considered.

Attachment Index

*Denotes forms or documents intended for return as a part of a complete bid response.

Public Service Company New Mexico / PNM (Hereinafter "Company")

<table>
<tr><td colspan="2">Project Information:
Advanced Metering Infrastructure (AMI) for electric meters in PNM's New Mexico service territory</td><td>Issued to Bidders:

May 20, 2022</td></tr>
<tr><td colspan="2">Responses MUST be Submitted Via Jaggaer</td><td>Complete Responses Must be Received On or Before:
July 8, 2022 – 1:00 PM Mountain Time</td></tr>
<tr><td>Sole Point-of-Contact (the "POC") or POC Designee:
Sean L'Ecluse</td><td>Phone Number:
505-241-3417</td><td>Email:
Sean.LEcluse@pnmresources.com</td></tr>
</table>

I. CORPORATE BACKGROUND & VALUES

Company (NYSE: PNM) is an energy holding Company based in Albuquerque, N.M., under management of PNM Resources. Through its utility and energy service subsidiaries, the PNM Resources family of companies supply electricity in New Mexico and Texas. Current information is available through its website http://www.pnmresources.com

Company believes safety and environmental sustainability are vital aspects of maintaining a thriving responsible business and holds such as cornerstones of our corporate culture. Accordingly, and to the greatest extent practical, decisions regarding Solicitations are in consideration of Bidders demonstrating reverence for green initiatives, responsible business practices, and safe work habits. Company may disqualify Bidders not demonstrating similar commitments. Solicitation lists specific criterion; but Bidders are typically expected to document a history of safe work and environmental stewardship and to secure the appropriate insurance policies and licenses to perform the work. Additionally, Company values business diversity and encourages the development of its local and small business community. If noted, some Solicitations may require a small business utilization plan.

II. GENERAL SOLICITATION CONDITIONS

This solicitation is neither a contract, nor an offer. No verbal statement may be construed as a contract or offer nor relied upon in anyway whatsoever during the course of this Solicitation. Bidders receive no rights by responding. Company will not reimburse any costs of participating in this Solicitation. Company may accept other than the lowest proposal. Company may accept or reject any proposal completely or in part. Company may reject all proposals with or without notice or explanation. At any point in this Solicitation, Company may abandon, decide to self-perform, or hire the work in some other manner or from bidders other than those originally included in the Solicitation. Company reserves the right to discontinue Solicitation at any time prior to signing a contract for any or no reason. Company reserves the right to award any portion, all, or none of the work on a local, regional, national, or international basis. Company has no obligation to buy exclusively from the Bidder awarded the contract for this Solicitation.

In submittal of a complete response, Bidders not already Party to an active Master with Company must review and provide comment to the terms and conditions of the enclosed form of Agreement. **Submitted proposals represent a firm offer in FULL AGREEMENT with the terms and conditions, unless the returned Agreement notes the Bidder's objection or exception to such.** Unless otherwise noted, each representation or promise of performance therein will be incorporated into the Agreement as a warranty or covenant.

This Solicitation is and remains property of Company. Forwarding or copying is prohibited. Use of PNM's logo or images or any public announcement or release of information regarding this Solicitation is prohibited. If received in error, please, immediately destroy, or return all printed or electronic copies to the Point of Contact. All Responses delivered to Company become property of Company.

III. COMMUNICATIONS DURING SOLICITATION

During this Solicitation, all communication between Company and Bidders must be limited to **the single point of contact (the "POC") listed above or his or her designee**. Any contact regarding this Solicitation with Company associates other than the POC may be grounds to disqualify proposals and terminate further communications regarding this effort.

Submit any questions regarding this Solicitation via email or otherwise in writing. Every effort will be made to respond to questions within two business days of receipt. **No questions or proposals received after the dates indicated herein will be entertained.**

If responses to inquiries constitute a material modification or addition to the original Solicitation, replies to questions will be made in the form of a Supplement to the Solicitation. Copies of Supplements are forwarded to all Bidders.

IV. SOLICITATION SCHEDULE / TIMELINE

Solicitation issued to Bidders	**May 20, 2022**
Questions from Bidders due no later than	**June 3, 2022**
Company's response to questions due no later than	**June 13, 2022**
Proposals due back from Bidders	**July 8, 2022**
Vendor Presentations	**Week of July 18, 2022**

V. PROJECT SCOPE, WORK REQUIREMENTS, & INFORMATION

Bidders shall prepare a response to perform the work, (the "Work"):

A. As set forth in the scope of Work document(s), included as "**ATTACHMENT 1 – SCOPE OF WORK**"; and
B. In consideration of the Bidders' exceptions and clarifications as submitted on the form included as "**ATTACHMENT 3 – SELLER'S EXCEPTIONS AND CLARIFICATIONS**"; and
C. In accordance with the terms and conditions of the Agreement included as "**ATTACHMENT 2 – EQUIPMENT PURCHASE AGREEMENT**"; and
D. At the price provided by Bidder in the format detailed in "**ATTACHMENT 6 – PROPOSAL FORMAT**".

VI. INSTRUCTIONS TO BIDDERS

Bidders shall prepare complete proposals in consideration of the following requirements and guidance:

A. **RFP Website Registration:**
   1. A bidder registration link will be sent by PNM from Jaggaer.
   2. All communications from Company to Bidders shall be sent via website.
   3. All submissions of information by Bidders shall be submitted via the website.

B. **Qualifications of Bidders:**

1. Bidders must meet minimum qualifications for performance of this Work and provide notice of certain particulars including, but not limited to:
   i. Bidders are required to provide notice and gain approval of PNM if intending to engage any person once employed by PNM or PNM Resources.
2. Bidder's agree to comply with safety, security, and compliance, postings or notices located at Company's premises or distributed to the Bidders; and reasonable requests to comply with third party registrations and training websites.

C. **Award Options:**

1. Work may be awarded to one or multiple Bidder(s) who may perform all or some portion of the Work described in **ATTACHMENT 1 – SCOPE OF WORK**.

D. **Submitting Proposals:**

1. Bidders shall submit responses via Jaggaer in a Microsoft Suite (Word, Excel, or PowerPoint) or .pdf formatted document.
2. Regardless of the form of submission, the delivery date of the Bidder's response is due on or before the due date without exception.
3. Failure to comply with proposal submission guidelines will result in disqualification from the bid process.
4. Disqualified proposals will not be returned.

E. **Terms & Conditions:**

1. Bidders' exceptions, assumptions or conditions imposed on or in the Solicitation responses, including all technical clarifications, conditions, or exceptions taken to the Work and / or any commercial term or condition must be clearly noted on the appropriate form of response.
2. Agreements returned without exceptions, assumptions, or conditions as outlined in F.1 are assumed to be submitted in acceptance of proposed terms, which are then assumed the terms of the Bidder's submitted proposal returned in good faith.

I. <u>COMPLETE PROPOSALS</u>

A. **Business Proposal**

1. Return all attachments as directed and labeled as they were originally sent.
2. Documents required for a complete proposal include:
   i. Bidder's response to PNM's form of agreement - redlined version of **ATTACHMENT 2 – EQUIPMENT PURCHASE AGREEMENT**
   ii. Pricing, completed as directed in **ATTACHMENT 6 – PROPOSAL FORMAT**
   iii. Technical Exceptions and Clarifications Form (if any) - completed as directed in **ATTACHMENT 3 – SELLER'S EXCEPTIONS AND CLARIFICATIONS**
   iv. Commercial Questionnaire completed as directed in **ATTACHMENT 4 – COMMERCIAL QUESTIONNAIRE**
   v. Technical Questionnaire **c**ompleted as directed in **ATTACHMENT 5 – TECHNICAL QUESTIONNAIRE**

B. **Price Proposal**

1. Bidder responses must contain price. Proposals with incomplete or no price will be disqualified.
2. Bidders submitted complete proposals and offering additional services not listed in this Solicitation; but for which Bidder suggests may be of value to Company, are invited to submit rate sheets or value add ideas as **"Suggested Services".**

II. Evaluation Criteria

The Bidder response to this RFP is intended to help PNM select the technology and support services that provide the best solution to meet its AMI needs. The proposal will be evaluated using a number of factors including, but not limited to:

- Compliance with the requirements of this RFP
- The proposed solution that best fits PNM's objectives for budgetary and operational needs, both current and future
- Experience of the company in providing such solutions
- Total cost to deploy proposed solution
- Total cost to maintain the system over its lifetime
- Simplicity, cost, and ease of installation
- Flexibility of the solution to facilitate system upgrades
- Cyber security of the overall solution and the individual components
- Availability and delivery schedule
- Training
- Ease of execution of an agreement by which to facilitate the business relationship

Scoring Factor	Evaluation Weighting
RFP and Commercial T&Cs Compliance	10%
Technical Solution	60%
Solution Cost and Pricing	30%

III. CONFIRMATION OF PROPOSAL SUBMISSION IS GOOD FAITH

By submitting a proposal, Bidder is (i) making a firm offer to purchase, manufacture or provide the equipment or materials described above, or to provide the Services described above; (ii) agreeing that Company may, in its sole discretion, accept or reject, in whole or in part, any Proposal; (iii) agreeing that Company has sole discretion in selecting a buyer, manufacturer or vendor for the equipment or materials or provider of Services; (iv) agreeing that Company may, in its sole discretion, discontinue negotiations at any time prior to execution of the agreement that covers the purchase or sale of the equipment and/or materials or for the performance of Services; (v) acknowledging Bidder's understanding that Company may be required to disclose all or part of any Proposal and related information and materials in the context of a legal or administrative proceeding or as otherwise required by law; and (vi) certifying that the individual submitting the Proposal is duly authorized to legally bind the Bidder.

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1. Overview of project

1.1. Request for Proposal

PNM issues this Request for Proposal (RFP) to solicit proposals for an Advanced Metering Infrastructure (AMI Solution) including advanced meters, a IEEE 802.15.4g Radio Frequency (RF) mesh neighborhood area network (NAN) with Wi-SUN certification, and Field Area Network (FAN) supporting NAN and potentially distribution automation field device telecommunication with the head end system(s), and meter data management system (MDMS) for its New Mexico service territory. This RFP seeks a solution that provides greatest total value for our customers, including AMI meters and associated equipment, which may include hybrid (cellular and mesh) communication models as appropriate. Furthermore, we are seeking information on customer energy portal capabilities to provide customers access to information about their energy usage as a potential component of a larger customer experience effort underway at PNM. For the purposes of this RFP, consider a rollout based on the following timeline which is dependent upon regulatory approval:

- Expected regulatory approval by Q4 2023. Work would commence once PNM receives regulatory approval, and this could occur earlier than Q4 2023.
- Q4 2023 Project kick off and planning for field work (meter installation and telecommunication deployment), back-office systems (Meter Data Management System (MDMS) and AMI Head End system) and system integration with PNM Customer Billing system;
- Q2 2024 thru Q4 2024 – Begin installation of communication system, head end system, MDMS and installation of initial 8000 meter field test sample;
- Q2 2025 - MDMS and head end system Go-Live with Banner interfaces;
- Q2 2025 – Begin installation of the remaining meters and telecommunication system with final completion to be done within 33 months ending in Q1 of 2028.

PNM is issuing this RFP to identify the AMI solution that best addresses the following requirements and objectives. While the vendor contract may be negotiated prior to the estimated deployment timeframe, the contract will be contingent on favorable regulatory approval.

Project initiation for the purposes of this analysis is expected to begin in the fourth quarter of 2023; however, PNM would want to initiate the project immediately upon receiving regulatory approval.

Vendors should include only the equipment and system capabilities that will be available by the first quarter of 2023. Other items should be clearly and specifically identified as roadmap items and an availability date must also be provided. In the event that the PNM reviews proposals with forthcoming capabilities, a prototype demonstration or successful field pilot may be required at a site negotiated based upon the extent of testing required.

The numbers of endpoints to consider for this RFP are as follows:

- Single Phase Electric Meters: 555,549
- Three Phase Electric Meters: 24,538

Table 1 contains a breakdown of the endpoints by form factor currently in PNMR's New Mexico service territory at the time of this RFP.

FORM	1 PH	3 PH	Total
01S	2000	0	2000
02S	522368	166	522534
03A	63	0	63
03S	271	19	290
04A	23	0	23
04S	1747	160	1907
05A	0	11	11
05S	0	59	59
06S	0	1	1
08A	0	2	2
08S	0	43	43
09A	0	2	2
09S	0	9258	9258
12S	28862	551	29413
13A	0	52	52
14	0	3	3
15	1	334	335
15A	0	6	6
16	14	13689	13703
16A	0	3	3
21	1	0	1
25S	199	0	199
35S	0	147	147
36S	0	18	18
45S	0	14	14
Grand Total	555549	24538	580087

Table 1 - Endpoints by form factor currently in PNMR's New Mexico service territory

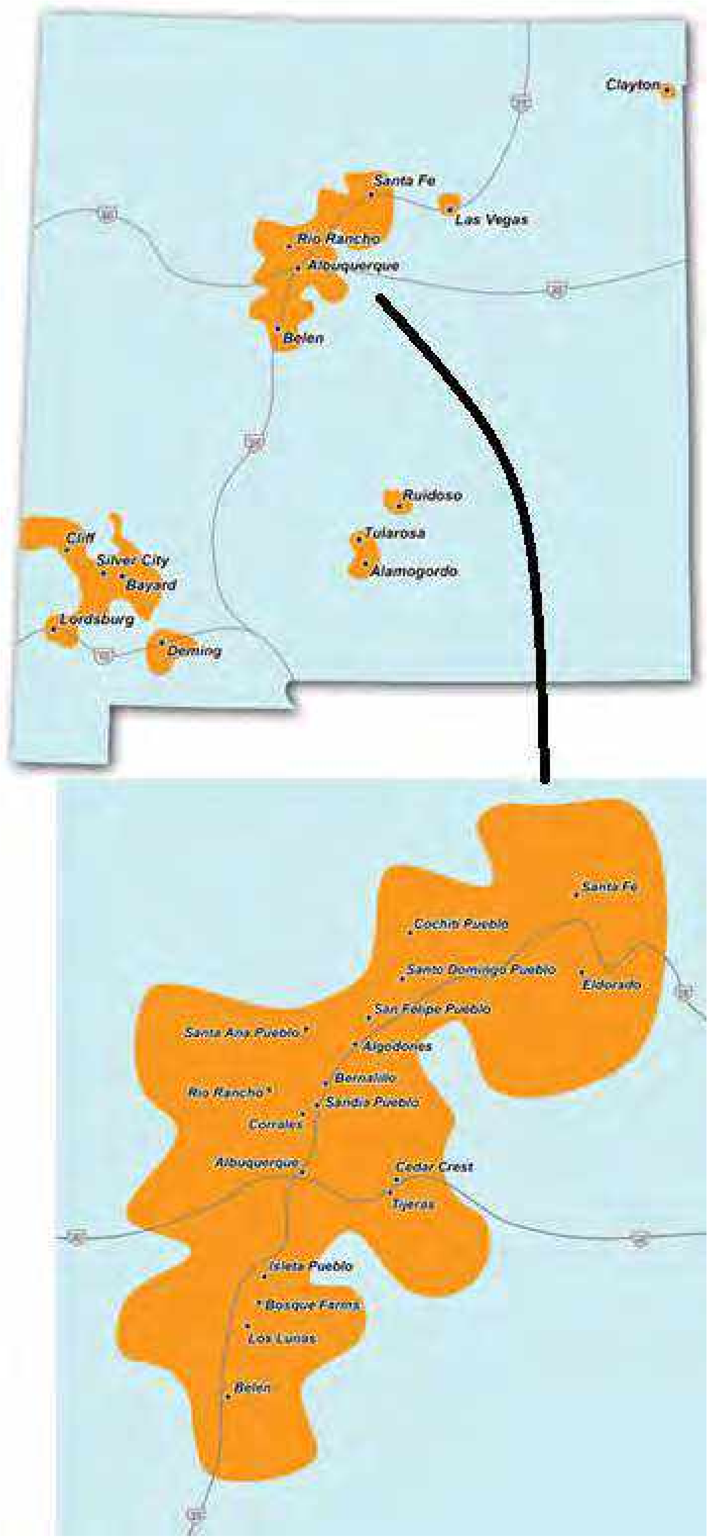
Table 2 contains a breakdown of the endpoints by form factor currently in PNMR's New Mexico service territory at the time of this RFP for which MV-90 is used for interrogation.

Form	Count of Meters in MV-90
02S	645
03S	6
04S	53
05S	3
08S	7
09S	2218
12S	33
15S	1
16S	211
35S	20
36S	3
Grand Total	**3200**

Table 2 - Endpoints by form factor for which MV-90 is used for interrogation

2. Background

PNM is the largest electricity provider in the state of New Mexico, and is a fully integrated electric utility headquartered in Albuquerque. PNM serves approximately 531,339 electric customers. PNM does not serve natural gas or water in the New Mexico service territory. The service territory is diverse in that it PNM serves metro and rural areas of the state, in both metropolitan and mountainous terrains. PNM serves the following cities and some of their surrounding areas: Albuquerque, Bernalillo, Rio Rancho, Santa Fe, Las Vegas, Clayton, Belen, Los Lunas, Ruidoso, Alamogordo, Tularosa, Deming, Lordsburg, Silver City, Bayard, and Cliff (see images below).



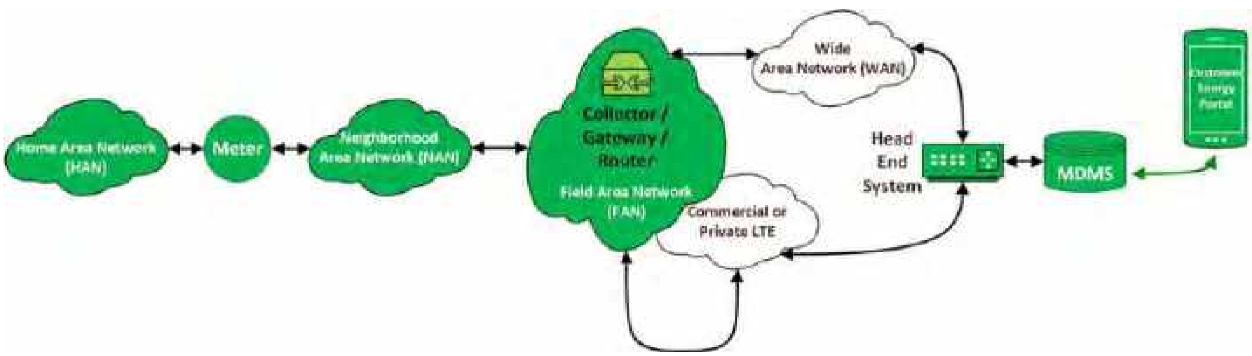
3. Scope of Work

2.1. Solicitation

PNM is seeking proposals that provide the greatest total value to customers for deployment of AMI throughout its New Mexico Service territory for its identified residential, commercial, and industrial customers (see Section 1 for meter forms considered part of this scope). While the vendor contract may be negotiated prior to the estimated deployment timeframe, the contract will be contingent on favorable regulatory approval.

For purposes of clarity, PNM has prepared this specification describing a two-way AMI System using Internet Protocol version 6 (IPv6) telecommunications. The advanced meter metrology, telecommunications and remote connect/disconnect switch shall be contained under the meter cover.

PNM envisions a multiple tier telecommunications approach to support the AMI system as illustrated below with green shading indicating the components in scope for this procurement. [1]



The NAN will preferably utilize an unlicensed frequency preferably operating in the 902 to 928 MHz frequency bands using IEEE 802.15.4g RF mesh networking and the Wi-SUN communication protocol and at the time of deployment. The AMI telecommunication solution shall have the capability of utilizing multiple, simultaneous technologies to communicate with the advanced meters with the numbered list aligning with the illustration below:

1) Wi-SUN mesh network advanced meter communicating to a collector/gateway/router with commercial carrier LTE communicating with the head end system
2) Wi-SUN mesh network advanced meter communicating to a repeater to increase mesh network coverage and connected to the collector/gateway/router with commercial carrier or private LTE communicating with the head end system

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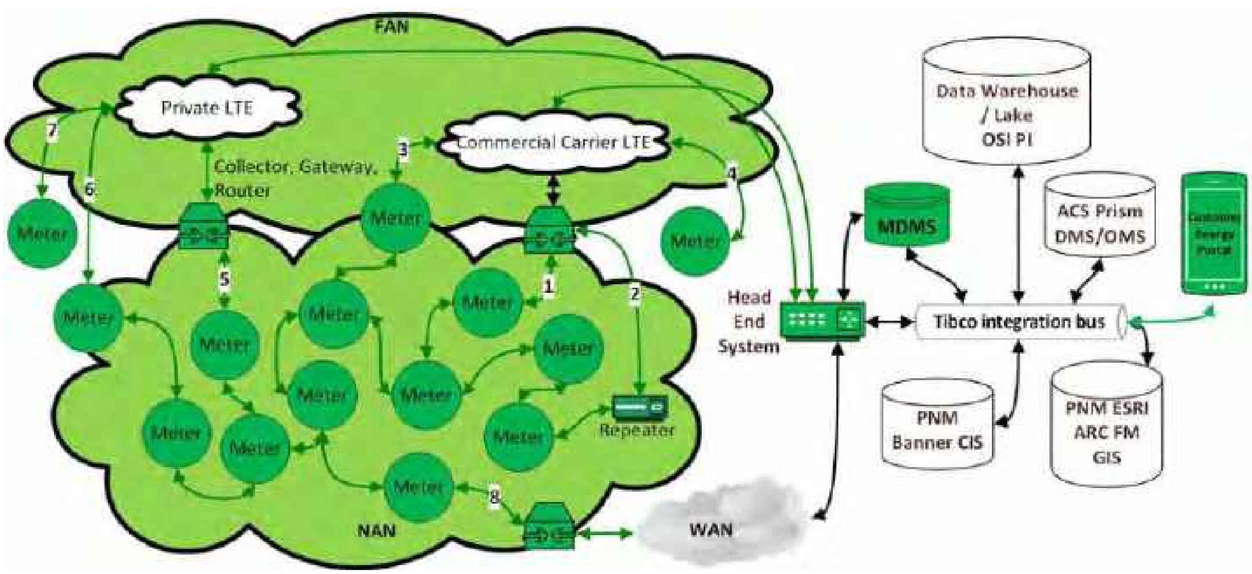
[1] The Wide Area Network primarily supports telecommunication for substation automation but can also be utilized for communicating between the FAN or NAN and the Head End System. The WAN can communicate through Fiber (MPLS with or without Dense Wavelength Division Multiplexing (DWDM), Microwave, Commercial Carrier Encrypted Cellular LTE, Private LTE, or Licensed 900 MHz RF to a head end system. WAN infrastructure is out of scope for this procurement, but the WAN to FAN interface is in scope for this procurement.

3) Wi-SUN mesh network advanced meter communicating to a meter with an embedded collector/gateway that connects to commercial carrier LTE communicating with the head end system
4) Advanced meter with embedded commercial carrier LTE communicating with the head end system
5) Wi-SUN mesh network advanced meter communicating to a collector/gateway/router with private LTE communicating with the head end system
6) Wi-SUN mesh network advanced meter communicating to a meter with an embedded collector/gateway that connects to private LTE communicating with the head end system
7) Advanced meter with embedded private LTE communicating with the head end system
8) Wi-SUN mesh network advanced meter communicating to a collector/gateway/router communicating through the WAN to the head end system

The high level conceptual architecture depiction below identifies the components that are in scope for this procurement with green shading and the numbered meter telecommunication pathways align with the numbered list above.



A hierarchical communications scheme based on Internet Protocol version 6 (IPv6) must be implemented for any RF Mesh solution so that the network can adapt to different communications scenarios. Vendors of "similar" systems choosing to submit bids shall do so for systems as close to the system specifications as possible and list any exceptions to the system specifications with the bid.

Strategically, PNM views a successful AMI implementation as a critical initial step in its grid modernization program. AMI allows the company to more effectively respond to changing customer needs, while at the same time improving operational efficiency and safety.

PNM is separately gathering information regarding a mobile application to facilitate customer self-service and interface with the existing PNM My Account. As a result, PNM is seeking information on how AMI data from the MDMS can provide information for a customer energy portal that provides customers with more granular information on their energy usage, including:

- Graphical representation of consumption and/or generation interval kWh data (usage or generation)
- Graphical representation of demand data (kW) presentment for demand-billed customers
- Providing customers with the capability to compare usage data to their historical usage (e.g. previous month, previous year).
- Support for customers billed with multiple accounts or locations.
- Ability to analyze all data in two views-chart and heat map- selectable by the customer
- Providing configurable threshold alerts

Specifically, PNM is targeting an AMI implementation to provide the following value to customers, company operations, and other stakeholders:

Customer experience

- Support improved customer engagement with improved usage and pricing information, including providing an interactive customer portal via multiple devices (computer, smart phone and tablet) with timely usage data and alerts, pricing and savings information and tips, data visualization, and bill prediction. This may include a mobile application that will initially incorporate monthly usage data and will later display AMI interval data.
- Improve customer satisfaction with service and product enhancements, including:
    - Improved meter reading accuracy
    - More efficient connect and disconnect service
    - Support future potential billing and payment options, such as pick your own bill date and pre-payment of service
    - Improved outage communications
    - Minimizing, or even eliminating the need for company personnel to access customer property
    - Supporting more accurate load research, which is then utilized to develop new pricing options and new product and service offerings
    - Customer energy management options and programs
    - Rates and pricing options that meet customer needs

Operational efficiency and effectiveness

- Improve meter reading, collections, and metering operations:
    - Collect 5-minute interval energy (kWh), demand (kW), and reactive power (kVAR) data for all customers to support anticipated DER adoption
    - Improve meter reading accuracy
    - Increase efficiency of connects and disconnects for moves and for non-payment
    - Improve safety and collections
    - Reduce tampering and diversion

- Enhance system analysis and operations
    - Improve distribution planning
    - Enhance distribution system reliability
    - Improve outage management with meter outage and restoration notifications and routed to the ACS Prism Outage Management System (OMS)
    - Provide data for Distributed Energy Resource (DER) hosting capacity studies
    - Support future policy- and regulatory-related requirements for energy efficiency, distributed generation and ratemaking models
    - Distribution voltage
        - Collect 5-minute interval voltage data (min/avg/max) to identify power quality issues.
        - Send voltage swell / sag notifications in near-real-time when voltage excursion goes outside definable max/min parameters
- Enable distributed energy resources including demand response, distributed generation, energy storage and electric vehicle tariffs and programs

Technical risk management

- Scalable, flexible, and upgradable system to protect against obsolescence and support future customer and operational needs
- Cyber secure system in all network domains
- AMI system that can be integrated with existing and future utility operations and customer systems
    - Tibco Integration Bus
    - PNM Banner Customer Information System (CIS)
    - ACS Prism Outage Management System (OMS)
    - ACS Prism Distribution Management System (DMS) and Distribution SCADA.
    - PNM ESRI Arc FM Geographic Information System (GIS)
    - OSIsoft PI data warehouse
- System that utilizes open industry recognized standards appropriate to the domain in which it is used consistent with the NIST Smart Grid Interoperability Panel's (SGIP's) Catalog of Standards. Specific standards are listed in the Technical Questionnaire document.
- Implemented with a reputable and continually advancing vendor within a potentially long-term vendor-company relationship

Industry Experience

- PNM is seeking a proposal which meets its requirements from a vendor experienced in similar or larger projects. Please provide your total installed base of AMI meters that matches the proposed solution for this procurement, as well as the total installed base of AMI meters with connect/disconnect switches.

3. Glossary

AMI System - Shall mean the collection of advanced meters, IEEE 802.15.4g Wi-SUN radio frequency mesh neighborhood area network (NAN), NAN collectors, gateways, and field area routers for the mesh network to communicate through the field area network (FAN) to the head end system, the head end system, and a meter data management system (MDMS) along with the systems and interfaces to integrate, manage and control these systems and technologies.

Advanced Meter - Advanced meters are the next generation of smart meters and represent a significant advancement in terms of supporting grid operations. Advanced customer metering has significantly greater computing and analytics capability embedded to augment the greater power.[2]

CIS - Shall mean the PNM Banner Customer Information System.

Collector - Shall mean a network device will collect data from the Radio Frequency (RF) mesh Neighborhood Area Network (NAN) for backhaul to the AMI Head End System.

Customer Portal – Shall mean an interactive website that is accessible via the internet that interfaces with the existing PNM My Account and enables the exchange and display of information for the customer.

Demand Response - Shall mean the use of either a Price Response and/or Direct Load Control System to manage demand from the customer.

Direct Load Control - Shall mean a process whereby an End Point Device is attached to a customer device such as a pool pump or air conditioner to turn electricity on and off according to the customer demand response program parameters.

Gateway – See Collector

Systems Integration – Shall be a term for the plans, methods and tools aimed at modernizing, consolidating, and coordinating with enterprise applications.

End Point Device - Shall mean the last device that is deployed in the field and that supports an application within the AMI System. Examples of End Point Devices include AMI Meters for electricity, or Direct Load Control switches.

FAN- Shall mean the field area network. The FAN includes the routers and repeaters needed to communicate between the Collector and the Neighborhood Area Network (NAN) Radio Frequency (RF) mesh connecting to individual AMI Meters.

Field Area Router – See Collector

HAN - Shall mean home area network. The HAN enables secure communication between the advanced meter and local devices at the customer premise that have registered or paired with the HAN network. Devices at the customer premise can include demand response (e.g., communicating thermostat, pool pump, etc.), advanced inverters supporting distributed energy resources (distributed generation, energy storage, and/or electric vehicles), building energy management control system(s), and energy portals.

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[2] Reference Department of Energy (DOE) Modern Distribution Grid Project Volume 2 - Advanced Technology Maturity Assessment http://www.doe-dspx.org/

Head End System – Shall mean the back-office system that manages the telecommunications with the advanced meters and routes meter data between the MDMS and advanced meters. The Head End System may also interface with the Outage Management System (OMS) to exchange outage data and information. The Head End System includes the network management for the AMI System telecommunications. The Head End System may include a meter head end and/or a head end router.

In-Home Display - Shall mean a device located in the customer premises and that is used to display information to the customer.

MDMS - Shall mean the meter data management system that, stores and processes (including validation, editing, and estimation (VEE)) and functions as the "system of record" for meter data. The MDMS provides billing determinate data and/or meter register read data to the Customer Information System (CIS) to support billing. The MDMS may also integrate with other utility systems (e.g., Outage Management System (OMS), Advanced Distribution Management System (ADMS), data warehouse/lake, and others).

NAN – Shall mean Neighborhood Area Network based utilizing IEEE 802.15.4g Radio Frequency (RF) mesh networking with Wi-SUN certified telecommunication components.

PCT –Shall mean a Programmable Communicating Thermostat that has a two-way communication capability using either the AMI System directly or through HAN communications, and that can be programmed by the customer as well as receive messages from the utility or other authorized service provider.

Smart Meter - Smart meters are digital, solid-state meters that are used to measure a customer's consumption during configured time intervals through a periodic polling mechanism. Smart metering can measure customer energy use or production, service voltage, outage events, and certain condition notifications, such as tampering and overheating. Additionally, smart meters have an embedded two-way communications module to allow remote meter reading as well as limited computing, software, and security elements. Smart meters may also have an optional service disconnect switch that can be remotely operated.[3]

Repeater - Shall mean a communication device which, if required in the AMI System, is installed typically on poles to extend the range of the RF Mesh network to communicate between Collectors and with the End Point Devices, Field Area Routers and End Point Devices, etc.

WAN - Shall mean the Wide Area Network which primarily supports telecommunication for substation automation but can also be utilized for communicating between the FAN or NAN and the Head End Router or Head End System. The WAN can communicate through Fiber (MPLS with or without Dense Wavelength Division Multiplexing (DWDM), Microwave, Commercial Carrier Encrypted Cellular LTE, Private LTE, or Licensed 900 MHz RF to a Head End System.

[3] Reference Department of Energy (DOE) Modern Distribution Grid Project Volume 2 - Advanced Technology Maturity Assessment http://www.doe-dspx.org/

EQUIPMENT PURCHASE AGREEMENT

This EQUIPMENT PURCHASE AGREEMENT (this "Agreement"), dated as of ______________ (the "Effective Date"), is made by and between ________________, a ______________ ("Seller"), and Public Service Company of New Mexico, a New Mexico corporation, as purchaser ("PNM"). PNM and Seller may be referred to collectively as the "Parties" or individually as a "Party."

RECITALS

WHEREAS, PNM is a public utility providing retail electric service in the State of New Mexico;

WHEREAS, Seller is a manufacturer and seller of Equipment described more fully in **Exhibit A** attached hereto; and

WHEREAS, PNM desires to purchase from Seller, and Seller desires to manufacture for and sell to PNM, pursuant to the terms and conditions of this Agreement, the Equipment set forth in **Exhibit A** attached hereto;

NOW THEREFORE, in consideration of the foregoing premises and the representations, warranties, covenants and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound thereby, the Parties agree as follows:

SECTION I
DEFINITIONS

1.1 **<u>Definitions.</u>** For purposes of this Agreement, the following terms shall have the following meaning:

a. **"Affiliate(s)"** of a Party means any other Person that, directly or indirectly, controls, is controlled by, or is under common control with such Party and any Person in which a Party has an ownership interest and to which the Party or an Affiliate of the Party provides services. For the purposes of this definition, "control" means the power to direct the management or policies directly or indirectly whether through the ownership of voting securities, by contract, or otherwise.

b. **"Applicable Law(s)"** means any law, statute, act, constitution, ordinance, rule, regulation, order, decree, injunction, license, permit, consent, approval, authorization, agreement or regulation of any federal, state, tribal or local government, department, office, agency, board or commission having jurisdiction over a Party, a subcontractor, the work site or any portion of the Work. Applicable Laws include, without limitation, Environmental Laws.

c. **"Business Day"** means a day other than a Saturday, Sunday or other day on which commercial banks in New York, New York are authorized or required by Law to close. Any event the scheduled occurrence of which would fall on a day that is not a Business Day shall be deferred until the next succeeding Business Day.

d. **"Change Order"** means a written instrument, in substantially the form attached hereto as "**Exhibit C-Change Order"**, signed by Seller and by the PNM Procurement Supervisor (or his or her designee) stating their agreement upon any change to any term or condition of **Exhibit A** or **Exhibit B** of this Agreement, including but not limited to, the nature of specifications relating to the following: the Work or the Equipment, any adjustment to the Purchase Price, the Guaranteed Delivery Date or the Destination.

e. **"Contract Documents"** means this Agreement plus all attachments (both in form and as completed), exhibits, specifications, schedules and drawings and any Change Orders or amendments thereto. The exhibits include the following and are incorporated by reference:

	Applicable	
	Yes	**No**
Exhibit A- TBD Name	☐	☐
Exhibit A-1- Equipment Specifications	☐	☐
Exhibit A-2- Sellers' Exceptions	☐	☐
Exhibit B- Pricing, Warranty, and Reporting	☐	☐
Exhibit C- Change Order	☐	☐
Exhibit D- Contractor's Obligations Regarding Supply Chain Cyber Security Risk Management	☐	☐

f. **"Destination"** means F.O.B. destination as more specifically described at Section 3.1 in this Agreement or other location determined by PNM and communicated to Seller in writing.

g. **"Environmental Law(s)"** means all federal, state, tribal and local laws, rules, regulations and ordinances governing, regulating or relating to public health, pollution, petroleum and petroleum products, wastes and discarded materials and contamination or the protection of the environment, or the protection of historic, archeological or cultural resources as may be amended from time-to-time.

h. **"Equipment"** means that equipment that is particularly described in **Exhibit A** attached hereto and incorporated by reference herein for all purposes in exchange for the Purchase Price, as modified by any Change Order.

i. **"Guaranteed Delivery Date"** means the final date of delivery of all Equipment purchased from Seller under the terms of this Agreement to the Destination, as set forth on **Exhibit A** hereto.

j. **"Material Breach"** shall mean a material misstatement or omission in any representation of a Party, or a breach or default in the performance of any agreement, covenant or obligations of a Party which, in any such case, deprives the non-breaching Party of a material right or benefits in any material respect.

k. **"Person"** means an individual, partnership, corporation, limited liability company, company, business trust, joint stock company, trust, unincorporated association, joint venture, government authority or other legally recognized entity of whatever nature.

l. **"PNM Procurement Supervisor"** means that person set forth on **Exhibit A**.

m. **"PNM Project Supervisor"** means that person set forth on **Exhibit A**.

n. **"Purchase Price"** means the price set forth in **Exhibit B**, as modified by any Change Order.

o. **"Seller's Project Manager"** means that person identified in Section 7.1, "Notices and Invoices."

p. "**Taxes**" means all federal, state, municipal, local or foreign income, profits, franchise, gross receipts, compensating, customs, duties, sales, use, goods and services, value added, personal property (tangible and intangible), stamp, transfer, conveyance, excise and other taxes, withholding, duties, levies, imposts and other similar charges and assessments imposed by or on behalf of any Governmental Authority, in each case whether such Tax arises by Applicable Law, contract or otherwise.

q. **"Uncontrollable Forces"** means any cause beyond the control of the Party affected and not due to its fault or negligence, including, but not limited to, acts of God, flood, earthquake, storm, fire, lightning, epidemic, pandemic, war, terrorist activity, riot, civil disturbance, sabotage, inability to obtain permits, licenses, and authorizations from any local, state, tribal or federal agency or person for any of the materials, supplies, equipment, or services required to be provided hereunder, fuel shortages, breakdown or damage to generation and transmission facilities belonging to PNM or any of its Affiliates, failure of facilities, strikes or other labor disturbances, or restraint by court or public authority, any of which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by the exercise of due diligence it is unable to overcome.

r. **"Work"** means the services, design and manufacture of the Equipment as more particularly described in **Exhibit A** of this Agreement and performed, furnished, or provided in accordance with the Contract Documents, which includes, but is not limited to, labor, materials, goods, supplies, tools, equipment, structures, facilities, products, items, plans, drawings, specifications, manuals, documents, work product, services, and permits provided to PNM hereunder and/or required to perform the Work, and the manufacture and fabrication of components of the Equipment.

SECTION II
PURCHASE AND SALE OF EQUIPMENT
SCHEDULE OF PAYMENTS

2.1 **Purchase.** PNM agrees to purchase from Seller, and Seller agrees to sell to PNM the Equipment. No modified or other conditions shall be recognized by the Parties unless specifically agreed to in writing as detailed in **Section 4.1 "Change Order"**.

2.2 **Purchase Price and Payment.** In consideration for the Equipment, PNM shall pay Seller the sum as specified in **Exhibit B** attached hereto and incorporated herein by reference (hereinafter called the **"Purchase Price"**), as modified by any Change Order. Such Purchase Price, except as specifically otherwise provided for in the Contract Documents, shall constitute the sole compensation payable to Seller for the Work, the Equipment or anything done in connection therewith, including any expenses incurred in complying with the terms and conditions of this Agreement. The Purchase Price shall be paid to Seller as set forth in **Exhibit B.**

2.3 **Taxes.** The Purchase Price does not include any sales Taxes or other transfer Taxes, if any, imposed in connection with the sale of the Equipment. If New Mexico gross receipts tax or applicable sales tax applies to the purchase, Seller shall itemize such tax on its invoices. In the event Seller fails to itemize and bill applicable New Mexico gross receipts tax or applicable sales tax at the time of invoice to PNM, Seller shall not thereafter seek reimbursement from PNM for any such tax or penalties or interest thereon. If Seller desires reimbursement from PNM for any other Tax or governmental charge payable by Seller because of the manufacture, sale or delivery of the goods but such Tax or charge is not incorporated into the price of the Equipment quoted by Seller, then PNM shall have no obligation to reimburse Seller for such tax or charge unless it is listed as a separate line item on Seller's quote to PNM for the Equipment under this Agreement. If the sale of goods or performance of services by Seller takes place on tribal land, Seller will comply with applicable state and tribal laws governing the reporting and payment of gross receipts taxes on those transactions. Seller shall be solely responsible for any taxes based upon Seller's net income.

2.4 **Payment of Subcontractors.** By submitting an invoice, Seller is certifying that all subcontractors and suppliers have been paid. In addition, if any payment is subject to NMSA 57-28-1, *et seq.* (2007) as amended (The Prompt Payment Act), PNM shall make payment to Seller within twenty-one (21) days after receipt of an undisputed request for payment, and Seller shall make prompt payment to its subcontractors and suppliers for amounts owed for work performed related to such invoice within seven (7) days after receipt of payment from PNM.

2.5 **Payment Within Thirty Days of Delivery.** Seller shall include an invoice for each shipment of Equipment delivered pursuant to this Agreement, and the balance due for such delivered Equipment will be paid by PNM within thirty (30) days after delivery at the Destination and acceptance of the Equipment by an appropriate PNM representative pursuant to Section 3.2. . Seller shall indemnify, defend and save PNM harmless from all laborers', materialman's and mechanic's liens arising out of the Work and from all attorney fees relating thereto incurred by PNM.

SECTION III
DELIVERY

3.1 **Shipment and Delivery.** The Equipment shall be delivered F.O.B. Destination no later than the Guaranteed Delivery Date as set forth in **Exhibit A**. For purposes of this Agreement, the Destination shall be defined as

___________________ [Please be as specific as possible when describing the location and include the physical address and name of location]. Freight shall be prepaid by Seller. Seller shall be responsible for off loading and setting the Equipment at the Destination.

3.2 **Title and Risk of Loss**. At the Destination, and upon acceptance by an appropriate PNM representative who has been afforded a reasonable opportunity to inspect the Equipment, all title to, risk of loss and responsibility for insurance or other protection of the Equipment from damages, theft, loss or destruction, shall pass from Seller to PNM.

SECTION IV
CHANGES IN THE WORK

4.1 **Change Order.** Any change to any term or condition of **Exhibit A** or **Exhibit B** of this Agreement shall only be changed by a properly executed Change Order. A Change Order shall constitute full and final settlement of all claims arising from or related to any Work or Equipment either covered or affected by the Change Order, or related to the events giving rise to the request for adjustment. Each Change Order shall be governed by the terms of this Agreement and shall reference the PNM Agreement number.

SECTION V
COMPLETION OF THE WORK

5.1 **Time is of the Essence.** The Parties acknowledge that time is of the essence for the delivery of the Equipment. Seller specifically acknowledges that PNM relies upon Seller's timely performance hereunder. Seller shall continuously monitor, report, forecast and control the progress of the Work and the timely delivery of the Equipment in accordance with the schedule set forth in **Exhibit A** of this Agreement. If there are any indications of delay or potential for delay, Seller shall take appropriate corrective measures and shall make all reasonable efforts to avoid any such delays.

5.2 **Monthly Status Reports.** Seller shall provide the PNM Procurement Supervisor with monthly progress updates due no later than the 5th day of every month (**"Monthly Status Reports"**). The update shall be transmitted in writing via email. Failure to provide reports by the 5th day of any given month shall result in a one percent (1%) reduction in the overall Purchase Price per occurrence. Such amounts, or part thereof, may be deducted by PNM from the balance due under this Agreement. The Monthly Status Reports shall be in the format set forth in **Exhibit B**.

5.3 **Notification of Delay.** If at any time during the performance of the Work or the production and manufacture of the Equipment, Seller becomes aware of any actual or anticipated event that may cause the delivery of the Equipment to occur after the Guaranteed Delivery Date, Seller shall **immediately** via email provide written notifications to the PNM Project Supervisor and PNM Procurement Supervisor. Seller shall specify the expected duration and anticipated effect of the delay, and the action being taken to correct the problem and make up for lost time. Provision of such notice does not relieve Seller of its obligations to deliver the Equipment by the Guaranteed Delivery Date. Any time extensions that PNM may agree to shall be incorporated into the Contract Documents through the execution of a Change Order.

5.4 **Final Status Report.** Seller shall provide the PNM Procurement Supervisor a written final status report no less than five (5) Business Days prior to shipment of the Equipment from Seller's production facility to Destination (the **"Final Status Report"**). The Final Status Report shall be in the format set forth in **Exhibit B**. Failure to timely provide the Final Status Report shall result in a one percent (1%) reduction in the overall Purchase Price.

5.5 **Late Delivery of Equipment; Liquidated Damages.** PNM will suffer financial losses if the Equipment is not delivered to the Destination on or before the Guaranteed Delivery Date by virtue of the loss of revenue to PNM due to the unavailability of the Equipment. It would be impracticable or extremely difficult to fix the actual damages resulting from such delay of delivery. Therefore, unless such late delivery is caused by PNM, if Seller delivers the Equipment to the Destination after the Guaranteed Delivery Date, then Seller will pay to PNM, as liquidated damages and not as a penalty, an amount equal to one and a half percent (1 ½%) of the Purchase Price per week for each calendar week of such delay until delivery occurs, not to exceed ten percent (10%) of the Purchase Price. This sum represents a reasonable endeavor by the Parties to estimate a fair compensation for the foreseeable losses resulting from late delivery of the Equipment, and shall be applicable regardless of the actual losses incurred. Such amounts, or part thereof, may be deducted by PNM from the balance due under this Agreement.

5.6 **Final Specifications.** A record set of specifications that shows every change from the original "approved" specifications shall be delivered to PNM upon delivery of the Equipment. Modified specifications resulting from any Change Order shall be forwarded to PNM periodically reflecting all modifications to the initially "approved" specifications. The final specifications shall reflect exact and actual conditions of the Work provided hereunder. Final specifications, and an electronic file of such specifications in the file format of _______, shall be delivered to PNM by Seller upon completion of the Work and delivery of the Equipment.

5.7 **Final Acceptance.** Seller shall perform all tests described in **Exhibit A** to ensure the quality of the Equipment sold hereunder. All Equipment shall conform and meet the specifications provided. Upon installation of the Equipment, Seller shall again test the Equipment to ensure it performs to the specifications provided in **Exhibit A**. When Seller believes it has achieved full and final completion of the Work and Services in accordance with the Contract Documents, Seller shall tender an executed Certificate of Final Completion, and shall submit a request for final payment. PNM shall issue its Final Acceptance substantially or reject Seller's determination of final completion in writing within ten (10) Business Days of Seller's Certificate of Final Completion.

SECTION VI
WARRANTY, INSPECTION, REJECTION

6.1 **<u>Warranty.</u>**

a. Seller represents, warrants and covenants that the Work performed and the Equipment delivered by Seller shall comply with the following warranties:

   i. The Equipment shall be manufactured according to industry standards, PNM's bid specifications, Seller's proposal, if applicable, and Seller-approved Equipment descriptions and specifications and other printed information relating to the Equipment provided to PNM by Seller and in effect as of the date of this Agreement.

   ii. The Equipment shall be new and free from defects in manufacture, materials, workmanship and design, function properly under ordinary use, and for a period of time set forth on **Exhibit B**, perform in accordance with all applicable specifications and documentation for such Equipment. If no time period is set forth on **Exhibit B**, the period of warranty shall be two (2) years.

   iii. Title to the Equipment, no matter where delivered, shall be free and clear of all liens and encumbrances, security interests or other adverse interests or claims.

b. PNM shall provide Seller with written notice of any alleged defect within forty-five (45) days after its discovery. If Seller is notified by PNM of a defect in Equipment within the warranty period plus forty-five (45) days after the expiration of such warranty period, such Equipment shall be repaired or replaced at PNM's option, with removal, re-installation, reassembly and retesting to be at Seller's expense. Seller shall be obligated to repair or replace the Equipment, F.O.B. Destination. Seller's obligations under this warranty are not exclusive, and do not limit PNM's ability to seek other contractual or statutory remedies, whether in law or in equity.

c. This warranty shall not apply to Equipment that has been subjected to negligence, abuse, accident, improper installation (if not installed by Seller or one of its subcontractors or agents), or improper operation, maintenance or storage, or modification not made by Seller. To the extent that under the terms of this Agreement the Equipment is to be installed by PNM, then in order to be covered by this warranty, the Equipment must be properly installed in accordance with Seller's instructions.

THIS WARRANTY IS IN LIEU OF ALL OTHER WARRANTIES OF ANY SORT, EXPRESS OR IMPLIED (EXCEPT TITLE), INCLUDING WITHOUT LIMITATION WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

6.2 **<u>Inspection.</u>** All material and components furnished must be as specified, and will be subject to inspection, testing and approval by PNM during manufacture and after delivery. Any inspection and testing by PNM shall not relieve the Seller of its obligations regarding defects or other failure of the Equipment to comply with specifications.

If any inspection or test is made by PNM on Seller's premises, the Seller, within reason and at no additional charge, shall make available to PNM facilities and assistance, including drawings, specifications, certifications, and other related data. If any such data is proprietary, PNM agrees to comply with reasonable procedures for safeguarding such data. PNM agrees to inspect the Equipment within three (3) Business Days of arrival at Destination and advise Seller and carrier of any observable damage or irregularity pursuant to Seller's receiving instructions.

6.3 **Right to Cure and Rejection.** PNM reserves the right to reject the entire shipment or such portion of any shipment which may be defective or fail to comply with specifications within thirty (30) days of delivery, notwithstanding any previous inspection by PNM, provided that Seller, at its sole expense, shall have a reasonable opportunity to cure defects or variations from specifications. If rejected, material or Equipment will be held for disposition at the expense and risk of Seller.

6.4 **Subcontractors' and Manufacturers' Warranties.** All subcontractors' and manufacturers' warranties and guarantees, express or implied, respecting any part of the Work and any materials used therein shall be deemed obtained by Seller for the benefit of PNM without the necessity of separate transfer or assignment thereof. However, Seller shall use its best efforts to cause all written warranties and guarantees to name PNM as the recipient and beneficiary. Seller shall execute such transfer and assignment documents as requested by PNM to assign all warranties and guaranties to PNM. If directed by PNM, Seller shall require subcontractors and manufacturers to execute such warranties and guarantees in writing to PNM.

SECTION VII
REPRESENTATIVES AND NOTICES

7.1 **Notices and Invoices.** All notices related to this Agreement which a Party is required or desires to give to the other shall be sent by personal delivery, or overnight courier and electronic mail, all charges prepaid, and addressed to the appropriate Parties identified below, or sent by PNM through DocuSign. Notices are effective upon receipt and shall be deemed received, if personally delivered, or delivered by courier, upon delivery, and if by DocuSign, upon receipt in recipient's email inbox as evidenced by DocuSign's history report.

PNM Procurement Supervisor

Phone:	505-241-____________
Fax:	505-241-____________
Email:	____________________
Address:	____________________
	____________________
	____________________

Seller Project Manager: ____________________
Phone: ____________________
Fax: ____________________
Email: ____________________
Address: ____________________
____
____

Invoices: Submit invoices to the PNM Project Supervisor at:

PNM Project Supervisor: ____________________
Address: ____________________
____
____

SECTION VIII
REPRESENTATIONS

8.1 **Authority.** The signatories executing this Agreement on behalf of PNM and Seller represent and warrant that they have the corporate and other authority to enter into this Agreement and to bind their respective companies to all the terms and conditions of this Agreement.

8.2 **Financial Standing.** Seller represents and warrants that it is financially solvent, able to pay its debts as they mature, and possesses sufficient working capital to complete the Work and deliver the Equipment and perform all of Seller's obligations required by this Agreement.

8.3 **Title.** Seller warrants marketable title to the Equipment free and clear of all liens. All materials and any inventions (whether or not patentable), trade secrets, ideas, concepts, software, source codes, copyrights, trade names and trade or service marks created or prepared for PNM, shall belong exclusively to PNM.

8.4 **Executive Order 13224.** Neither Seller, nor any of its employees has been, is not presently, nor shall be a party or person with whom a "U.S. Person" (as defined in Executive Order 13224) is prohibited from transacting business with under Applicable Laws. All evidence of identity provided by Seller to PNM is true and accurate.

SECTION IX
TERMINATION

9.1 **Termination by PNM.**

a. **Termination by PNM for Cause.**

i. PNM may terminate this Agreement if Seller becomes insolvent or seeks protection, voluntarily or involuntarily, under applicable bankruptcy laws.

ii. PNM may terminate this Agreement at any time prior to Final Acceptance upon thirty (30) days prior written notice to the Seller if there is a Material Breach by Seller of any term or condition of this Agreement and Seller fails to cure such breach within the thirty (30) day time period.

iii. Notwithstanding the above, PNM may immediately, and with no prior notice required, terminate the Agreement if Seller fails to deliver the Equipment by the Guaranteed Delivery Date.

iv. If PNM terminates this Agreement under this Section 9.1(a) and it is later determined that Seller was not in default, then such termination shall be deemed a termination for convenience pursuant to Section 9.1(b) herein.

v. In the event of such termination for cause, Seller shall be liable to PNM for any and all damages, losses, costs and expenses incurred by PNM arising out of or resulting from such default. In the event of failure to cause delivery of the Equipment by the Guaranteed Delivery Date, PNM, in addition to all other remedies available to it, shall immediately be relieved of all obligations and Seller shall immediately refund all payments made to it by PNM under this Agreement.

b. **Termination by PNM for Convenience.** PNM may, upon advance written notice to Seller, suspend, abandon, cancel or terminate this Agreement or any portion of the Work for any reason whatsoever including the convenience of PNM without regard to whether or not Seller has defaulted or failed to comply with the provisions of the Contract Documents. PNM shall be liable to Seller for an amount equal to the actual expenses incurred by Seller up to the time of Seller's termination for Work performed and materials provided in conformity with this Agreement, plus without duplication, an amount equal to Seller's substantiated, reasonable direct costs necessarily incurred (1) in procuring materials and equipment as authorized by PNM (but less all amounts refunded, whether through cancellation of purchase orders or otherwise) and in cancelling purchase orders as instructed by PNM, and (ii) in preparation for the parts of the Work not yet performed prior to termination, plus an amount for a reasonable part of the profit Seller would otherwise have earned for the parts of the Work performed prior to such termination, provided that the total sum payable shall be an amount not to exceed the Purchase Price. Seller shall not be entitled to any other costs or damages whatsoever arising out of the termination of this Agreement. The termination by Seller of this Agreement, and payment of the costs specified, shall be the sole and exclusive remedy and measure of damages for the events and circumstances described and termination of this Agreement and Seller hereby waives, releases and discharges any and all other remedies, claims, damages and losses, at law or in equity.

Contractor shall deliver to PNM all reports, drawings or other documents prepared or received in connection with the Services, and all other Work Product completed for PNM under this Agreement.

9.2 **Termination by Seller for Cause.**

a. Seller may terminate this Agreement for cause if PNM fails to pay Seller any undisputed amount due as set forth in the payment schedule in **Exhibit B**, and such failure continues for thirty (30) days following receipt of written notice thereof from Seller.
b. Seller may terminate this Agreement at any time prior to Final Acceptance upon thirty (30) days prior written notice to PNM if there is a Material Breach by PNM of any term or condition of this Agreement and PNM fails to cure such breach within the thirty (30) day time period.
c. In the event of such termination for cause, PNM shall be liable to Seller in the same manner as described in **Section 9.1(b)**.

SECTION X
LIABILITY

10.1. **Compliance with Laws.** Seller shall comply with all Applicable Laws. Seller shall indemnify, defend and hold harmless PNM, including its Affiliates, and their respective directors, officers, employees, representatives, agents, advisors, consultants and counsel from and against any claims, damage and expense (including reasonable attorney fees) asserted or awarded against or incurred by such indemnitees arising out of, resulting from or related to, the violation by Seller of any Applicable Laws.

10.2. **Safety Materials.** Seller agrees and warrants that all materials, supplies, equipment and/or services provided in connection with Seller's obligations and deliveries under this Agreement meet the safety standards established and promulgated under the Federal Occupational Safety and Health Act of 1970, 29 U.S.C.A. § 651, *et seq.*, and, if applicable, the Federal Motor Carrier Safety Acts, or under any Applicable Law of a state in lieu thereof, for the protection of employees who will be affected by the use or performance of said materials, supplies, equipment and/or services. Seller agrees and warrants that to the extent any material safety data sheets are required; they will be properly prepared and provided to PNM. Seller shall comply with all Applicable Laws governing safety and the safe operation of commercial motor.

10.3. **Indemnification.**

a. To the fullest extent permitted by law, Seller shall indemnify, defend and hold harmless PNM, including its Affiliates, and their respective directors, officers, employees, representatives, agents, advisors, consultants and counsel (collectively, "Indemnified Persons") against liability, claims, damages, losses or expenses, including attorney fees (together, the "Claims") arising out of or resulting from (1) performance or non-performance of the Work; (2) this Agreement; (3) injuries to or death of any and all individuals including members of general public or any employee, agent or independent contractor of PNM or its Affiliates arising out of or connected in any manner with performance or non-performance of any of the Work or any defect in the Equipment or Seller's failure to warn PNM, its Affiliates or its customers about risks relating to the Equipment or use of the Equipment, whether or not the conduct of Seller or any subcontractor was tortious and whether any other party contributed to the injuries or death; (4) damage to, loss and/or destruction of property, including loss of use of any property, arising out of or connected in any manner with performance of the Work or any defect in the Equipment or Seller's failure to warn PNM, its Affiliates or its customers about risks relating to the Equipment or the use of the Equipment whether or not the conduct of Seller or any subcontractor was tortious and whether any other party contributed to the property damage; or (5) third party claims of any kind, whether based upon negligence, strict liability, products liability or otherwise, arising out of or connected in any manner to Seller's or any of its contractor's acts or omissions in breach of this Agreement or resulting from failure to comply with this Agreement. Seller shall only be liable to the extent the Claims are caused by, arise out of or result from the acts or omissions of Seller or any of its subcontractors or suppliers or supplier of its subcontractors or anyone directly or indirectly employed or retained by them or anyone for whose acts they may be liable. In any claim against PNM for which Seller owes a duty to provide indemnity, PNM shall have the right to choose its own counsel.

b. **Intellectual Property Rights Infringement Indemnity**. Seller warrants that none of the Work, or the results thereof, performed by Seller, or any subcontractor, or the documents, drawings, goods or equipment produced, designed, fabricated, delivered or assembled by Seller, or any subcontractor, pursuant to this Agreement, infringe upon or violate any patent, copyright, trade secret, or any other intellectual or property rights of any third party. If any third party makes a claim or commences a proceeding against PNM or any of its Affiliates alleging such an infringement or violation, Seller shall indemnify, defend and hold harmless the Indemnified Persons from and against any and all claims asserted or awarded against or incurred by such indemnitees. PNM will notify Seller if any such claim is made or proceeding is commenced. PNM may, at its option, be represented by separate legal counsel in any such claim or proceeding. Seller shall reimburse PNM the costs and expenses incurred by PNM in being so represented, including reasonable attorney fees. If the use of any of the Work, or the results of such Work, or documents, goods, or equipment, or any part thereof, furnished under this Agreement is held in any such claim or proceeding to constitute an infringement and/or is enjoined, whether temporarily or permanently, Seller shall, at its sole cost and expense, either:

   i. procure for PNM the right to use the Work and the results of such Work; or
   ii. replace the Work and the results of such Work with non-infringing results, documents, items, goods or equipment having the equivalent functionality as the infringing or allegedly infringing results, documents, goods or equipment; or
   iii. modify the results of such Work and the results of such Work so as to make them non-infringing, but equivalent in functionality.

Best Efforts. Seller shall use its best efforts to obtain for the benefit of PNM identical intellectual property rights indemnification protection in all subcontracts, purchase orders, and other agreements entered into under this Agreement. The requirements of this subsection are not intended to abridge, abrogate, amend, or otherwise affect Seller's obligations under this **Section 10.3**.

10.4 **Third Party Claims.** Seller shall keep the Indemnified Person informed as to the status and progress of third party claims, actions, suits or proceedings. The Indemnified Person shall have the right to be represented by its own counsel and such counsel may participate in such claim, action, suit or proceeding, and the fees and expenses of such counsel shall be reimbursed by Seller. Seller shall not agree to or conclude any settlement that affects the Indemnified Person without the prior written approval of the Indemnified Person.

SECTION XI
INSURANCE

11.1 **Insurance.**

a. **Seller's Insurance.** Prior to commencement of the Work, Seller shall obtain the insurance required by this Agreement and all insurance that may be required under the Applicable Laws, written by insurance companies with a rating of at least an "A- VIII" in the latest edition of A.M. Best. Unless otherwise indicated below, each insurance policy of Seller shall be written on an occurrence basis. Prior to commencing the performance of Work under this Agreement and upon renewal of any of policies required in Section 11.1.b, Seller shall furnish to PNM a completed certificate of insurance coverage which references this Agreement number and evidences the required minimum insurance and extensions as specified in Section 11.1.b. Seller shall specifically provide thirty (30) days prior written notice to PNM of cancellation, termination, non-renewal, or any material change of any insurance policies. Should such policy be cancelled, non-renewed or materially changed, Seller is obligated to reinstate all required coverages prior to expiration or amendment of the policy. Failure to maintain the required insurance coverage or failure to comply fully with any of the insurance provisions as may be necessary to carry out the terms and provisions of this Agreement shall be deemed to be a material breach of this Agreement. Insurance requirements in this Agreement are independent of, and in addition to, Seller's liability under this agreement. Nothing in this Agreement shall be deemed to limit Seller's liability under this Agreement to the limits of the insurance coverages required hereunder. Seller shall be solely responsible for payment of all deductible or retention amounts pertaining to any insurance required hereby.

b. **Minimum Coverage**. Seller shall obtain and maintain in effect, at its sole cost and expense, until all the obligations under this Agreement are satisfied, policies of insurance that contain the coverages and limits of liability set forth below. Umbrella/excess liability insurance may be used to meet the required limits of liability provided that policies are written on a following form basis or on a form that provides coverage that is at least as broad as that found on each of the underlying insurance policies.

i. **Commercial General Liability Insurance**, or the equivalent, with a minimum limit of One Million Dollars ($1,000,000) combined single limit per occurrence for bodily injury and property damage, One Million Dollars ($1,000,000) each organization or person for personal and advertising injury, Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products-completed operations aggregate. The insurance shall provide severability of interests or cross liability provisions permitting one insured to bring a claim against another insured, and shall be endorsed to include PNM and its Affiliates and their respective directors, officers, managers, representatives, agents and employees as additional insureds with respect to Work performed under this Agreement, limited only to the extent required, if applicable, by NMSA 1978 § 56-7-1, as amended. The insurance maintained by Seller shall be primary with respect to the interest of PNM, and any other insurance or self-insurance maintained by PNM or its Affiliates is in excess and shall not contribute to Seller's insurance in all instances regardless of any like insurance that PNM or any of its Affiliates may have.

ii. **Commercial Automobile Liability Insurance**, or the equivalent, with limit of not less than One Million Dollars ($1,000,000) per accident with respect to any vehicle used in the performance of any Work required to be performed by Seller pursuant to the Agreement. The insurance shall be endorsed to include PNM and its Affiliates and their respective directors, officers, managers, representatives, agents and employees as additional insureds, limited only to the extent required, if applicable, by NMSA 1978 § 56-7-1, as amended. The insurance maintained by Seller shall be primary with respect to the interest of PNM, and any other insurance or self-insurance maintained by PNM or its Affiliates is in excess and shall not contribute to Seller's insurance policies in all instances regardless of any like insurance coverage that PNM or any of its Affiliates may have.

iii. **Property Insurance.** Seller bears the entire risk of loss, theft, damage or destruction of Equipment in whole or in part from any reason whatsoever (" Loss"), until such time as title and risk of loss has transferred to PNM, including while being manufactured and in transit. If a Loss occurs to the Equipment, Seller shall immediately notify PNM of the same and Seller shall, unless otherwise directed by PNM, immediately repair the same. If Seller or PNM determine that any item of Equipment has suffered a Loss beyond repair ("Lost Equipment") prior to transfer of risk of loss, then Seller shall immediately replace the Lost Equipment with similar equipment in good repair, condition and working order. Seller at its sole expense shall provide all-risk property insurance insuring at all times the full replacement cost of the Equipment against all risks of loss or damage from every cause whatsoever (including collision in the case of vehicles) for an amount not less than the full replacement cost of the Equipment until such time as title and risk of loss has transferred to PNM, including while being manufactured and in transit. PNM shall be named as loss payee with respect to all insurance covering damage to or loss of any Equipment, and the proceeds of any such insurance shall be payable to PNM as loss payee. Any deductibles under said Property Insurance coverages shall be the responsibility of Seller and shall be remitted to PNM within sixty (60) days of the Loss, unless otherwise agreed to by PNM in writing following the Loss.

iv. **Professional Liability Insurance** covering errors and omissions committed in the performance of professional services with limits not less than Two Million Dollars ($2,000,000) per claim. Such insurance shall provide coverage for professional services performed by Seller, its subcontractors, or anyone directly or indirectly employed by any of them. Such insurance may be written on a claims-made basis rather than an occurrence basis as long as the policy (a) has a retroactive date prior to the date of project commencement, and (b) is maintained by Seller throughout the performance of the Services and for at least three (3) years thereafter either through policies in force or through an extended reporting period.

c. **Waiver of Subrogation.** Seller waives on behalf of itself and its insurers all rights of any recovery or subrogation against PNM, its Affiliates and consultants, and their respective directors, officers, managers, representatives, agents and employees. All insurance policies in any way related to the Work and secured and maintained by Seller shall include clauses stating each insurer waives all rights of recovery, by subrogation or otherwise, against PNM and its Affiliates and their respective directors, officers, managers, representatives, agents and employees.

d. **Subcontractors.** Seller shall require that each subcontractor comply with the insurance requirements set forth in **Section 11.1.a and 11.1.b "Minimum Coverage."** Before permitting any of its subcontractors to perform any Work, Seller shall obtain a certificate of insurance from each such subcontractor evidencing that such subcontractor has obtained the required minimum insurance and has added PNM and its Affiliates and their respective directors, officers, managers, representatives, agents and employees, and Contractor, as additional insureds with respect to the coverages under 11.1.b except for workers' compensation insurance, and any other insurance where additional insured is required of Seller in **Section 11.1**. All policies of subcontractors shall include a waiver of any right of subrogation of the insurers thereunder against Seller and PNM and its Affiliates and their respective directors, officers, managers, representatives, agents and employees..

SECTION XII
OTHER PROVISIONS

12.1 **Uncontrollable Forces.** Neither Party shall be considered to be in default in respect to any obligation hereunder if delays in or failure of performance shall be due to Uncontrollable Forces. Neither Party shall, however, be relieved of liability for failure of performance if such failure is due to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. The Party whose performance hereunder is so affected shall immediately notify the other Party of all pertinent facts and take all reasonable steps to promptly and diligently prevent such causes if feasible to do so, or to minimize or eliminate the effect thereof without delay. Seller shall make no claim and hereby waives, release and discharges any and all claims for additional compensation or damages by reason of any delay or additional services due to an Uncontrollable Force.

12.2 **Gratuities and Anti-Kickback Provisions.**

a. Seller shall not, under any circumstances, extend any gratuity or special favor to employees of PNM that might be reasonably constructed as an attempt to influence the recipients in the conduct of their official duties.

b. Seller agrees to abide by the Anti-Kickback Act of 1986, 41 U.S.C.A. § 51, *et seq.*, which prohibits any person from (1) providing, attempting to provide or offering to provide any kickback; (2) soliciting, accepting, or attempting to accept any kickback; or (3) including, directly or indirectly, the amount of any kickback in the cost of work charged to PNM by Seller. It is also agreed that Seller will not engage the services of any individual who has been convicted after September 29, 1988, or for a period of five (5) years after the date of conviction, of fraud or any other felony arising out of a contract with the federal government. Such person(s) is(are) prohibited from working in a management or supervisory capacity, serving as a consultant, or serving on the board of directors.

12.3 **INTENTIONALLY OMITTED**

12.4 **NERC Compliance.** In the event that Seller's performance of its obligations under the Agreement requires unescorted physical or cyber access to any PNM facilities or assets considered to be within the scope of the North American Electric Reliability Corporation's (**"NERC"**) reliability standards for Critical Infrastructure Protection, PNM may determine in its reasonable opinion that pursuant to NERC standards, heightened requirements are applicable for granting access to such facilities. In such cases, prior to Seller being granted such access, PNM's Project Supervisor shall notify Seller's Project Manager that the following requirements shall apply: Seller shall obtain, pay for and electronically deliver to PNM at the email address specified below the following for each of Seller's employees or agents who will require unescorted physical access or cyber/electronic access to PNM NERC CIP cyber assets: (i) background checks acceptable to PNM prepared by PNM-approved vendors consisting of identity verification with all names and social security numbers used, or similar identification information, and a ten (10) year physical address and criminal record check; and (ii) certification that cyber security training, as required by PNM, has been completed by such employee or agent. Background checks must be updated at least every seven (7) years, or upon PNM's request, in its sole and absolute discretion. If Seller has not provided the necessary information, as identified in (i) and (ii) above, to PNM at the time unescorted physical access is requested, Seller shall either (i) provide an escort having the requisite training and background checks on file with PNM; or (ii) request, subject to availability, a PNM escort and reimburse PNM for the cost of such escort. In the event that Contractor terminates, for cause or otherwise, any of Seller's employees or agents that maintain approved unescorted physical access or approved cyber/electronic access to PNM, Contractor shall provide same day notice to PNM by electronic delivery to NERC.ComplianceCommittee@pnmresources.com that Seller has terminated such employee or agent. Any breach of this Section 12.4 by Seller or any of its subcontractors shall be considered to be a material breach. To the fullest extent permitted by law, Seller shall indemnify, defend and hold harmless PNM's Indemnified Persons from and against any and all Damages (including but not limited to fines or penalties assessed pursuant to federal or state law or regulation), arising out of or resulting from any breach of this Section 12.4 by Seller, its subcontractors or either of their respective Affiliates.

12.5 FERC Compliance. Pursuant to the regulations and order of the Federal Energy Regulatory Commission ("FERC") regarding the FERC Standards of Conduct ("SoC") and the FERC Code of Conduct ("CoC"), employees and agents of Seller shall not disclose restricted transmission or customer information of PNM, as defined under SoC regulations, or non-public market information of PNM, as defined under CoC regulations, that comes into possession of Seller, its employees or agents. Seller shall obtain, pay for and electronically deliver to PNM at ferc.compliance@pnmresources.com the following for each of Seller's employees or agents who will have access to such restricted information of PNM: (i) certification that SoC or CoC training, as applicable, or as may be required by PNM, has been completed by such employee or agent that will or could have access to such restricted information during the course of providing the services required hereunder; (ii) certification that each of Seller's employees or agents who will have access to such restricted information of PNM will not act as a conduit of such information for others.

12.6 **INTENTIONALLY OMITTED**

12.7 **Intellectual Property.**

a. **Intellectual Property Rights.** Seller agrees that all inventions, works of authorship and other proprietary data, and all other materials (as well as the copyrights, patents, trade secrets, and similar rights attendant thereto) conceived, reduced to practice, authored, developed or delivered by Seller or any subcontractor and their respective employees, agents, consultants, contractors, and representatives either solely or jointly with others, during and in connection with the performance of the Work under this Agreement and that relate to the business of PNM, shall be owned by PNM (**"Intellectual Property"**). Neither Seller nor any subcontractor nor their respective employees, agents, consultants, contractors or representatives shall have the right to disclose or use any of the Intellectual Property for any purpose whatsoever or to communicate to any third party the nature of or details relating to the Intellectual Property. Seller hereby grants, assigns and conveys to PNM all right, title, and interest in and to the Intellectual Property. Seller agrees that it will not seek, and that it will require each subcontractor and all of Seller's and its subcontractors' employees, agents, consultants, contractors, and representatives not to seek patent, copyright, trademark, registered design, or other protection for any rights in any Intellectual Property. Seller agrees that it shall do and that it will require its subcontractors and all of Seller's and its subcontractors' employees, agents, consultants, contractors, and representatives to do, at PNM's expense, all things and execute all documents as PNM may reasonably require to vest in PNM or its nominees the rights referred to herein and to secure for PNM or its nominees all patent, trademark, or copyright protection, including but not limited to assisting in preparing applications, signing all necessary documents, testifying in court proceedings, and retaining secret information concerning any of the Intellectual Property that is not public knowledge. Seller warrants and represents that it has or will have the right, through written agreements with its employees, to secure for PNM the rights called for in this Section. Further, in the event Seller uses any subcontractor, consultant, or other third party to perform any of the Work under this Agreement, Seller agrees to enter into and provide to PNM such written agreements with such third party, and to take such other steps as are or may be required to secure for PNM the rights called for in this Section. Seller further agrees to provide the names and addresses of all agents, contractors, consultants, representatives, or other third parties who perform work on behalf of Seller under this Agreement. The obligations contained in this Section shall survive the expiration or termination of this Agreement.

b. **License of Pre-Existing Intellectual Property.** Seller hereby grants to PNM and its Affiliates a fully paid and non-exclusive, irrevocable, perpetual license to use and copy, and to create derivative works of any pre-existing copyrighted, patented and/or proprietary work that is incorporated into the Work or the results of the Work, including the right to create sub-licenses without any duty to account to Seller or any subcontractor. If so requested by PNM, Seller and subcontractor shall cooperate with PNM in executing all such assignments, oaths, declarations and other documents as may be prepared by PNM to effect and evidence the foregoing. Seller agrees to enter into and provide to PNM such written agreements with such third party, and to take such other steps as are or may be required to secure for PNM the rights called for in this Section.

c. Seller shall insert in any subcontract or purchase order issued under this Agreement restrictions on the use of such Intellectual Property.

12.8 **Survival.** Seller's representations, warranties, indemnities and other obligations under this Agreement or any certificate, document or instrument delivered pursuant to or in connection with this Agreement shall survive consummation of the transaction contemplated herein, and shall survive expiration, termination or cancellation of the Agreement and any amendments thereto.

12.9 **Assignment.** Seller shall not assign this Agreement or any part hereof, or any of its rights or obligations under this Agreement without the prior written consent of PNM. In no event shall PNM's written consent be construed as discharging or releasing Seller from the performance of its obligations specified in this Agreement. PNM may, at its option and at any time, assign this Agreement, in whole or in part. PNM shall promptly notify Seller in writing of any such assignment, unless such assignment is to an Affiliate of PNM. In the event PNM assigns this Agreement, it shall be relieved of all financial responsibility related to the portion of this Agreement so assigned.

12.10 **Remedies.** The remedies reserved in this Agreement are cumulative and in addition to any other remedies in law or equity which may be available to PNM. The election of one or more remedies shall not bar the use of other remedies unless the circumstances make the remedies incompatible.

12.11 **No Waiver.** No delay, failure or refusal on the part of a Party to exercise or enforce any right under this Agreement shall impair such right or be construed as a waiver of such right or any obligation of the other Party, nor shall any single or partial exercise of any right hereunder preclude other or further exercise of any right. The failure of a Party to give notice to the other Party of a breach of this Agreement shall not constitute a waiver thereof. Any waiver of any obligation or right hereunder shall not constitute a waiver of any other obligation or right, then existing or arising in the future. To be effective, a waiver of any obligation or right must be in writing and signed by the Party waiving such obligation or right.

12.12 **Dispute Resolution of this Agreement.** If the Parties are unable to resolve any dispute related to this Agreement within thirty (30) days after written notice by one Party to the other Party of the occurrence of the event or circumstances giving rise to the dispute, the dispute may be submitted to mediation upon the mutual agreement of the Parties. In the event the Parties do not agree to mediate the dispute or are unable to resolve the dispute through mediation and the aggregate amount of the claim (including counterclaims) is less than One Hundred Thousand Dollars ($100,000), then the dispute shall be resolved by binding arbitration. Except as set forth herein, such arbitration shall be governed by the Commercial Rules of the American Arbitration Association, as amended from time to time. A Party demanding arbitration shall give the other Party timely notice of such election pursuant to the notice section of this Agreement, with a copy to PNMR Services Company-Legal Department, 414 Silver Ave SW, Albuquerque, New Mexico 87102, and such notice shall describe the nature of the dispute and the amount in controversy. The Parties shall then jointly select an arbitrator and failing such mutual agreement within ten (10) days after written notice demanding arbitration, the arbitrator shall be appointed by the Chief District Court Judge from Bernalillo County, New Mexico. The arbitration shall be held in Albuquerque, New Mexico. Discovery shall be by agreement of the Parties or as ordered by the arbitrator, provided that the Parties shall comply with the following minimum discovery requirements: at least ten (10) calendar days prior to the arbitration, the Parties shall exchange copies of all exhibits to be used at the arbitration and a list of witnesses and a summary of the matters as to which each witness is expected to testify.

12.12.1 **Disputes In Excess of $100,000.** In the event the Parties do not agree to mediate the dispute or are unable to resolve the dispute through mediation, and if the aggregate amount of the claim in dispute equals or exceeds One Hundred Thousand Dollars ($100,000), then the Parties may agree to submit the matter to binding arbitration under the Commercial Rules of the American Arbitration Association, as amended from time to time, and failing such agreement, either Party may bring an action, and such action shall be in the federal or state courts of New Mexico.

12.12.2 **Costs and Other Provisions.** All costs of mediation or arbitration, including the fees of the mediator or arbitrator, shall be split equally by the Parties, except that the Parties shall be responsible for payment of their own attorney fees, expert fees, preparation fees, travel, and similar costs. This agreement to arbitrate shall be specifically enforceable under the prevailing arbitration law of the State of New Mexico. Indemnity claims are not subject to mandatory arbitration. Nothing in this Section shall affect, restrict, condition, or otherwise limit a Party's right to terminate this Agreement pursuant to **Section IX "Termination"** of this Agreement.

12.12.3 **Payment of Undisputed Amounts; Other Remedies.** When any dispute occurs, Seller shall continue the Work in accordance with the terms hereof and PNM shall continue to make payments of undisputed amounts in accordance with this Agreement, and the Parties shall otherwise continue to exercise their rights, and fulfill their respective obligations, under this Agreement. While any consultations, mediation or arbitration is pending, neither Party shall exercise any other remedies hereunder arising by virtue of the matters in dispute; provided, however, PNM's right to terminate under this Agreement shall not be suspended.

12.13 **Governing Law and Venue.** The entire relationship of the Parties, this Agreement, any remedies of the Parties, and any litigation or legal proceedings (whether grounded in tort, contract, statutory, equitable, or other law) between, involving, or arising among, the Parties, shall be governed by, interpreted in accordance with, and construed consistent with, the laws of the State of New Mexico, without regard to the choice of law principles which may otherwise dictate the application of the laws of another state. Any lawsuit or other legal proceeding (whether at law or in equity) between, involving, or arising among the Parties, or relating to this Agreement, shall be commenced and pursued solely in the state or federal courts located in Bernalillo County, New Mexico, and the Parties hereby waive any challenge they may have to the jurisdiction of such courts, consent to jurisdiction and venue in such courts, and relinquish any right to seek a change of venue or forum for any reason, including the alleged inconvenience of the venue or forum.

12.14 **Regulatory Proceedings.** Seller shall testify, when requested by PNM, in any court or governmental or regulatory agency hearings or proceedings relative to the Work performed under this Agreement, subject to payment of reasonable compensation.

12.15 **Entire Agreement.** The Contract Documents represent the entire agreement and understanding between PNM and Seller with respect to the subject matter hereof and performance of the Work, and supersedes all other oral or written provisions. THE PARTIES HEREBY AGREE THAT NO TRADE USAGE, PRIOR COURSE OF DEALING OR COURSE OF PERFORMANCE UNDER THIS AGREEMENT SHALL BE PART OF THIS AGREEMENT OR SHALL BE USED IN THE INTERPRETATION OR CONSTRUCTION OF THIS AGREEMENT. If any Work was performed by Seller under oral agreement or under a limited notice to proceed prior to the execution of this Agreement, then this Agreement shall apply thereto in the same manner as if made before such Work was performed.

12.16 **Severability**. If any provision of this Agreement is determined to be invalid, void, illegal or unenforceable, the balance of this Agreement shall remain in effect. Furthermore, in lieu of such illegal, invalid or unenforceable provision, there shall be added automatically as a part of this Agreement a provision as similar in its terms to such illegal, invalid or unenforceable provision as may be possible and be legal, valid and enforceable.

12.17 **No Consequential Damages.** Unless otherwise specifically provided for in this Agreement, in no event shall PNM be liable under any provision of this Agreement for any indirect, consequential, special, punitive or incidental damages or costs of Seller or its Affiliates, whether based in contract, tort (including, without limitation, negligence or strict liability), or otherwise, and Seller hereby waives, releases and discharges any and all indirect, consequential, special, punitive and incidental damages and costs. Consequential damages shall include, without limitation, loss of revenue, loss of profits, cost of capital, loss of business reputation and opportunity. Notwithstanding the foregoing, the prohibition against indirect, consequential, special, punitive or incidental damages or costs set forth in this Section 12.17 shall not apply to Damages arising out of Contractor’s breach of Section 12.4.

12.18 **Binding Effect**. This Agreement and all provisions shall inure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

12.19 **Counterparts**. This Agreement and all other Contract Documents may be executed in any number of counterparts, each of which so executed shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument. PNM and Seller may retain a duplicate copy (e.g. electronic image, photocopy, facsimile) of this Agreement, which shall be considered an equivalent to this original.

12.20 **Amendment(s) in Writing.** This Agreement may not be amended except by a writing signed by duly authorized representatives of the Parties.

12.21 **Agreement Authors.** The Parties have agreed to this Agreement and no ambiguity shall be construed against any Party based on the identity of the author or authors of this Agreement.

12.22 **Confidentiality.** Any information or data of PNM provided to Contractor, or to which Contractor is given access during the term of this Agreement at any time, whether such information is in written, verbal, electronic or any other form ("Confidential Information"), is proprietary to PNM and shall be treated as confidential and not disclosed by Contractor to any third party without PNM's prior written consent.

Contractor may disclose such Confidential Information and data to its employees and Subcontractors, but only on a "need to know" basis. Such Confidential Information and data may only be used for the purpose of performing the Services that are required of Contractor pursuant to this Agreement, and for no other purpose.

Such Confidential Information and data may not be copied except as required to perform the Services.

Upon completion of the Services, Contractor shall destroy all copies, replicas or reproductions in any form in its possession of the Confidential Information and data. Notwithstanding the foregoing, the Contractor may retain a single copy of such Confidential Information and data as may be reasonably required for purposes of compliance with the Contractor's legal retention policies, and applicable laws and regulations. In addition, the Contractor shall not be required hereunder to destroy or remove Confidential Information and data stored in an electronic database until such time as such data would, in the regular course of business, be purged.

Further, Contractor acknowledges and agrees that all data and Confidential Information collected, produced or generated, and all reports, test results, plans, models, documents and other written materials produced pursuant to this Agreement or in connection with any services to be performed or contemplated to be performed hereunder or in connection with any goods to be provided or contemplated to be provided/purchased hereunder, shall be and remain the sole property of PNM, shall be strictly confidential, shall not be copied or reproduced in any way, except for the use by Contractor for the Services, and shall not be disclosed or communicated, verbally or in writing, by Contractor to any third party, or used in any way except as required by law or for the purposes required or intended by the Agreement.

If required by PNM, Contractor and any of its employees or agents performing Services under or in connection with this Agreement shall execute confidentiality and nondisclosure agreements in the form required by PNM.

If Contractor is served with process of law, including but not limited to subpoenas requiring Contractor to produce, release or disclose any Confidential Information received, collected, produced or generated by Contractor pursuant to this Agreement contemplated herein, Contractor shall immediately notify PNM and allow PNM, at its sole expense and cost, to challenge the process of law, including any subpoena. A disclosure under this provision means any circumstance when the security, integrity, or confidentiality of any PNM information has been compromised, including but not limited to incidents where PNM information has been damaged, lost, corrupted, destroyed, or accessed, acquired, modified, used, or disclosed by any unauthorized person, by any person in an unauthorized manner, or for an unauthorized purpose. The duties of this Section 12.22 will survive the expiration or early termination of this Agreement for a period of five (5) years following such expiration or early termination.

12.23 **Restrictions Regarding Specially Designated Nationals.** The Office of Foreign Assets Control ("OFAC") in the Department of Treasury ("Treasury") publishes and regularly updates an integrated and comprehensive list of designated parties referred to as Specially Designated Nationals ("SDNs") with whom U.S. persons are prohibited from conducting transactions or providing services, and whose assets are blocked. Contractor represents and warrants it has checked the SDN list and that neither Contractor, nor any of its employees or subcontractors who may provide services pursuant to this Agreement, is currently on that list.

12.24 **Non-Asbestos Containing Material.** All Equipment provided by Seller to PNM hereunder shall be free of asbestos unless Seller has notified PNM in advance and has obtained PNM's prior written consent to the use of the specific Equipment. Seller shall indicate in the material description of all related shipping documents (packing list, material test reports, and other shipping documents) whether the Equipment is non-asbestos or asbestos containing material. Upon request, Seller shall provide to PNM, on Seller's letterhead, confirmation of the date when Seller and manufacturer discontinued selling products known to contain asbestos. Seller shall include this Section 12.24 in any subcontracts issued hereunder.

12.25 **Notification of Data Breach.** Contractor shall immediately notify PNM of any suspected or known unauthorized access, disclosure, misuse, or misappropriation of PNM's Confidential Information ("Data Breach") that comes to Contractor's attention. Such notification shall be made to PNM no more than twenty-four (24) hours after Contractor suspects or knows of the Data Breach. Contractor shall also take the following actions in the event of a Data Breach: (a) designate a single individual employed by Contractor who must be available to PNM twenty-four (24) hours per day, seven (7) days per week as a primary contact regarding Contractor's obligations under this Section 16.35; (b) not provide any additional notification or disclosure to the public regarding the Data Breach which mentions PNM or any of its Affiliates without first obtaining prior written approval from PNM; (c) cooperate with PNM in investigating, remedying, and taking any other action PNM deems necessary regarding the Data Breach and any dispute, inquiry, or claim that concerns the Data Breach; (d) follow all reasonable instructions provided by PNM regarding the Confidential Information affected or potentially affected by the Data Breach; (e) take any actions necessary to prevent future Data Breaches; and (f) notify PNM of any third-party legal process relating to the Data Breach. Notwithstanding the foregoing, Contractor may disclose information relating to a Data Breach as required by applicable law or by proper legal or governmental authority. Contractor shall give PNM prompt notice of any such legal or governmental demand and reasonably cooperate with PNM in any effort to seek a protective order or otherwise to contest such required disclosure.

12.26 **Conflict of Interest.** Contractor shall exercise reasonable care and diligence to prevent any actions or conditions which would result in a conflict with PNM's interests.

12.27 **Supply Chain Cyber Security Risk Management.** Without limiting the effectiveness of any other terms of this Agreement, Contractor shall comply with all obligations of "Contractor" that are set forth in Exhibit D to this Agreement for all procurements that fall under the requirements of the CIP-013 standard as identified in the Individual Task Authorization (ITA), Purchase Order (PO), Statement of Work (SOW) or other contractual instrument. In the event of a conflict between the Terms and Conditions of this Exhibit and the Terms and Conditions of any Agreement between the parties, the Terms and Conditions of this Exhibit shall govern.

To all Distributors and Value Added Resellers (VARs):
Please pay particular attention to the following sections that outline your responsibility to obtain information from and/or flowing down these requirements to the OEMs whose product you are providing to Public Service Company of New Mexico.
Par. 3 f. iii (b) "Contractor's Response Plan - Unrelated Security Incidents"
Par. 5 a (i) "Disclosure and Remediation of Known Vulnerabilities"
Par. 6 "Hardware, Firmware, Software, and Patch Integrity and Authenticity
Par. 7 "Patching Governance"
Par. 8 "Viruses, Firmware and Malware
Par. 13 "Return or Destruction of Company Information"

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of the date first written above.

SELLER	**PUBLIC SERVICE COMPANY OF NEW MEXICO** **Executed by PNMR Services Company as Agent**
By: ______________________________	By______________________________
Name:____________________________	Name:___________________________
Title:_____________________________	Title:____________________________

EXHIBIT A

Equipment, Delivery, and Key Personnel

Destination

Equipment shall be delivered to____.

Equipment; Scope of Work

Seller shall perform the following task(s) and provide the following Equipment and/or deliverables:

1) Seller shall provide one (1) ______________________________ in accordance with the specifications detailed in **Exhibit A-1 - Equipment Specifications** taking into account Seller's exceptions to the specification as detailed in **Exhibit A-2 – Seller's Exceptions**.
2) No deviation from **Exhibit A-1 - Equipment Specifications** shall occur other than those detailed in **Exhibit A-2 – Seller's Exceptions** or those agreed to in writing by the Parties via a Change Order as detailed in **Exhibit C – Change Order**.

Deadlines and/or Milestones; Guaranteed Delivery Date

1) **Equipment MUST be delivered no later than ___________ (the Guaranteed Delivery Date).** Furthermore the production of the Equipment shall be completed in accordance with the following production schedule:

Supervisors and/or Key Personnel

PNM Project Supervisor: ________________________________
Phone: 505-241-______
Fax: 505-241-______
Email: ______________

PNM Procurement Supervisor: ________________________________
Phone: 505-241-______
Fax: 505-241-______
Email: ______________

Seller Project Manager: ________________________________
Phone: ______________
Fax: ______________
Email: ______________

Exhibit A-1 - Equipment Specifications

Exhibit A-2 – Seller's Exceptions

EXHIBIT B

Pricing, Warranty and Reporting

Part 1. Purchase Price.

The Purchase Price for the Equipment, including any Work, shall be $ ______________________ (the "Purchase Price") plus any Taxes provided for in Section 2.3 of the Agreement. Such Taxes must be separately shown on any invoice, and the invoice must indicate the amounts or transactional components to which the Taxes apply. Any changes to the Purchase Price shall be documented in a Change Order.

Part 2. Payment Schedule.

The Purchase Price shall be paid according to the following installment schedule, calculated as a percentage of the Purchase Price:

10% upon full execution of the Agreement by both Parties.
35% upon completion of design review, and acceptance and sign off of the same by PNM.
35% upon actual shipment of Equipment from Seller.
20% upon Final Acceptance of Equipment by PNM.

Seller shall issue invoices to PNM based on the above installment schedule.

Part 3. Term of Warranty as Set Forth in Section 6.1.

__________________ years after Final Acceptance is executed by PNM.

Part 4. Reports.

A. Monthly Status Reports

The Monthly Status Reports (referenced in Section 5.2) shall include:

a. Current status of the Equipment (stage of production).
b. Determination if the production of the Equipment is on schedule to be delivered on or before the Guaranteed Delivery Date (as set forth on **Exhibit A**).
c. Any issues Seller perceives to be potential risks to the schedule.

B. Final Status Reports

The Final Status Report shall include:

a. The actual date shipment of the unit will commence.
b. Method(s) of transportation from the Seller's facility to the Destination.
c. The names of the transportation companies for each leg of the transportation.
d. The transportation route.
e. The duration of each leg of transport.
f. The date and time of delivery to the Destination as best can be determined by Seller.
g. Proof of insurance during the delivery process.

EXHIBIT C – CHANGE ORDER

Change Order to Equipment Purchase and Sale Agreement

AGREEMENT #:	AGREEMENT EFFECTIVE DATE:	CHANGE ORDER #:	CHANGE ORDER EFFECTIVE DATE:

SUBJECT:	
SELLER:	

The Parties have determined it to be in their best interest to amend the subject Agreement as follows:

[insert changes to **Exhibit A** or **Exhibit B** of this Agreement]

All other terms and conditions of said Agreement as it heretofore may have been amended shall be and remain the same.

ACCEPTED FOR:

SELLER | **PNM**
Executed by PNMR Services Company as agent

BY: ______________________________	BY: ______________________________
NAME: ____________________________ [printed] TITLE: _____________________________ DATE: _____________________________	NAME: ____________________________ [printed] TITLE: _____________________________

EXHIBIT D

CONTRACTOR'S OBLIGATIONS REGARDING SUPPLY CHAIN CYBER SECURITY RISK MANAGEMENT

1. **Definitions**. The following definitions apply only to the terms and conditions in this Exhibit.

   a. "CEII" means Critical Energy Infrastructure Information and/or Critical Electric Infrastructure Information.

   b. "Company" means Public Service Company of New Mexico.

   c. "Company Information" means for purposes of these terms and conditions, any and all information concerning Company and its business in any form, including, without limitation, the products and services provided under this Agreement that is disclosed to or otherwise learned by Contractor during the performance of this Agreement.

   d. "Contractor" means _______________.

   e. "Contractor's Proprietary Information" means any Contractor information that is considered highly confidential where disclosure outside of the Company may result in significant loss of Contractor's intellectual property, PII, etc. and may cause damage to the operational effectiveness or otherwise substantially disrupt significant business operations, with examples including but not limited to: source code, private encryption keys, or Company Information.

   f. "Disclosed" means any circumstance when the security, integrity, or confidentiality of any Company Information has been compromised, including but not limited to incidents where Company Information has been damaged, lost, corrupted, destroyed, or accessed, acquired, modified, used, or disclosed by any unauthorized person, by any person in an unauthorized manner, or for any unauthorized purpose.

   g. "PII" means Personally Identifiable Information.

   h. "Security Incident" means any circumstance when (i) Contractor knows or reasonably believes that Company Information hosted or stored by Contractor has been Disclosed; (ii) Contractor knows or reasonably believes that an act or omission has compromised or may reasonably compromise the cybersecurity of the products and services provided to Company by Contractor or the physical, technical, administrative, or organizational safeguards protecting Contractor's systems or Company's systems storing or hosting Company Information; or (iii) Contractor receives any complaint, notice, or communication which relates directly or indirectly to a Security Incident involving (A) Contractor's handling of Company Information or Contractor's compliance with the data safeguards in this Agreement or applicable laws in connection with Company Information or (B) the cybersecurity of the products and services provided to Company by Contractor.

2. Notice by Contractor to Company of Security Incident Occurrence.

   a. Contractor agrees to notify Company immediately by calling the PNMR Service Desk at 505-241-2678 and by email at securitynotifications@pnmresources.com whenever a Security Incident occurs.

   b. The written notice shall include the date and time of the Security Incident occurrence (or the approximate date and time of the occurrence if the actual date and time of the occurrence is not precisely known) and a detailed summary of the facts and circumstances of the Security Incident, including a description of (a) why the Security Incident occurred (*e.g.*, a description of the reason for the system failure), (b) the amount of Company Information known or reasonably believed to have been Disclosed, and (c) the measures being taken to address and remedy the occurrence to prevent the same or a similar event from occurring in the future.

   c. Contractor shall provide written updates of the notice to Company addressing any new facts and circumstances learned after the initial written notice is provided and shall provide such updates within a reasonable time after learning of those new facts and circumstances.

d. Contractor shall reasonably cooperate with Company in Company's efforts to determine the risk posed by the Security Incident, including providing additional information regarding the Security Incident upon request from Company.

3. Contractor's Response Plan.

a. Development of Response Plan. Contractor shall develop and implement a "Response Plan," which shall include policies and procedures to address Security Incidents. The Response Plan shall include appropriate provisions for mitigating the harmful effects of Security Incidents and addressing and remedying such occurrences to prevent the recurrence of similar Security Incidents in the future. Contractor shall provide Company access to inspect its Response Plan. The development and implementation of the Response Plan shall follow industry standard practices, such as those practices that at a minimum are consistent with the contingency planning requirements of National Institute of Standards and Technology (NIST) Special Publication 800-61 Rev. 2 (Computer Security Incident Handling Guide), NIST Special Publication 800-53 Rev. 4 (Security and Privacy Controls for Federal Information Systems and Organizations) CP-1 through CP-13 and the incident response requirements of NIST Special Publication 800-53 Rev. 4, IR-1 through IR-10 as those standards may be amended.

b. Implementation of Response Plan. Immediately upon learning of a Security Incident related to the products and services provided to Company, Contractor shall implement its Response Plan and, within 24 hours of implementing its Response Plan, shall notify Company in writing of that implementation as described above.

c. Prevention of Recurrence. Within ten days of a Security Incident, Contractor shall develop and execute a plan that reduces the likelihood of the same or a similar Security Incident from occurring in the future consistent with the requirements of its Response Plan and industry standards (e.g., NIST Special Publication 800-61 Rev. 2 and NIST Special Publication 800-184, as may be amended) and shall communicate that plan to Company. Contractor shall provide recommendations to Company on actions that Company may take to assist in the prevention of recurrence, as applicable or appropriate.

d. Coordination of Incident Response with Company. Within five days of notifying Company of the Security Incident, Contractor shall recommend actions to be taken by Company on Company-controlled systems to reduce the risk of a recurrence of the same or a similar Security Incident, including, as appropriate, the provision of action plans and mitigating controls. Contractor shall coordinate with Company in developing those action plans and mitigating controls. Contractor will provide Company guidance, recommendations, and other necessary information for recovery efforts and long-term remediation and/or mitigation of cyber security risks posed to Company Information, equipment, systems, and networks as well as any information necessary to assist Company in relation to the Security Incident.

e. Notification to Affected Parties.

i. Contractor will, at its sole cost and expense, assist and cooperate with Company with respect to any investigation of a Security Incident, disclosures to affected parties, and other remedial measures as requested by Company in connection with a Security Incident or required under any applicable laws related to a Security Incident.

ii. In a particular Security Incident results in Company Information being Disclosed such that notification is required to be made to any person or entity, including without limitation any customer, shareholder, or current or former employee of Company under any applicable laws, including privacy and consumer protection laws, or pursuant to a request or directive from a governmental authority, such notification will be provided by Company, except as required by applicable law or approved by Company in writing. Company will have sole control over the timing and method of providing such notification.

f. Unrelated Security Incidents. In the event

i. Contractor's Proprietary Information, related to the products and/or services provided to the Company under this Agreement, has been corrupted or destroyed without authorization or has been accessed, acquired, compromised, modified, used or disclosed by any unauthorized person, or by any person in an unauthorized manner or for an unauthorized purpose;

ii. Contractor knows or reasonably believes that an act or omission has compromised the cybersecurity of the products and services provided by Contractor to an entity other than Company; or

iii. Contractor receives any complaint, notice, or communication which relates directly or indirectly to

(a) Contractor's handling of Restricted Information or Contractor's compliance with applicable law in connection with Restricted Information or

(b) the cybersecurity of the products and services provided by Contractor to an entity other than Company ("Unrelated Security Incident"),

Contractor shall provide to Company a confidential report describing, to the extent legally permissible, a detailed summary of the facts and circumstances of the Unrelated Security Incident, including a description of (1) why the Unrelated Security Incident occurred, (2) the nature of the Restricted Information disclosed, and (3) the measures being taken to address and remedy the occurrence to prevent the same or a similar event from occurring in the future.

4. Access Control Policy.

a. Development and Implementation. Contractor shall develop and implement policies and procedures to address the security of Contractor's remote and onsite access to Company Information, Company systems and networks, and Company property (an "Access Control Policy") that is consistent with the personnel management requirements of industry standard practices (e.g., NIST Special Publication 800-53 Rev. 4 AC-2, PE-2, PS-4, and PS-5 as may be amended) and also meets the following requirements. Contractor shall provide Company access to inspect its Access Control Policy.

b. Company Authority Over Access. In the course of furnishing products and services to Company under this Agreement, Contractor shall not access, and shall not permit its employees, agents, contractors, and other personnel or entities within its control ("Contractor Personnel") to access Company's property, systems, or networks or Company Information without Company's prior express written authorization. Such written authorization may subsequently be revoked by Company at any time in its sole discretion. Further, any Contractor Personnel access shall be consistent with, and in no case exceed the scope of, any such approval granted by Company. All Company authorized connectivity or attempted connectivity to Company's systems or networks shall be in conformity with Company's security policies as may be amended from time to time with notice to the Contractor.

c. Contractor Review of Access: Contractor will review and verify Contractor personnel's continued need for access and level of access to Company Information and Company systems, networks and property on a quarterly basis and will retain evidence of the reviews for two years from the date of each review.

d. Notification and Revocation: Contractor will notify Company within 72 hour(s) in writing (no later than close of business on the same day as the day of termination or change set forth below) when:

(i) any Contractor personnel no longer requires such access in order to furnish the services or products provided by Contractor under this Agreement,

(ii) any Contractor personnel is terminated or suspended or his or her employment is otherwise ended,

(iii) Contractor reasonably believes any Contractor personnel poses a threat to the safe working environment at or to any Company property, including to employees, customers, buildings, assets, systems, networks, trade secrets, confidential data, and/or employee or Company Information,

(iv) there are any material adverse changes to any Contractor personnel's background history, including, without limitation, any information not previously known or reported in his or her background report or record,

(v) any Contractor personnel loses his or her U.S. work authorization, or

(vii) Contractor's provision of products and services to Company under this Agreement is either completed or terminated, so that Company can discontinue electronic and/or physical access for such Contractor personnel.

Contractor will take all steps reasonably necessary to immediately revoke such Contractor personnel electronic and physical access to Company Information as well as Company property, systems, or networks, including, but not limited to, removing and securing individual credentials and access badges, multifactor security tokens, and laptops, as applicable. Further, for such revoked Contractor personnel, Contractor will return to Company any Company-issued property including, but not limited to, Company photo ID badge, keys, parking pass, documents, or electronic equipment in the possession of such Contractor personnel. Contractor will notify Company at NERC.ComplianceCommittee@pnmresources.com once access to Company Information as well as Company property, systems, and networks has been removed.

5. <u>Disclosure and Remediation of Known Vulnerabilities</u>.

a. Contractor shall develop and implement policies and procedures to address the disclosure and remediation by Contractor of vulnerabilities and material defects related to the products and services provided to Company under this Agreement including the following:

(i) Prior to the delivery of the procured product or service, Contractor shall provide or direct Company to an available source of summary documentation of publicly disclosed vulnerabilities and material defects in the procured product or services, the potential impact of such vulnerabilities and material defects, the status of Contractor's efforts to mitigate those publicly disclosed vulnerabilities and material defects, and Contractor's recommended corrective actions, compensating security controls, mitigations, and/or procedural workarounds.

(ii) Contractor shall provide or direct Company to an available source of summary documentation of vulnerabilities and material defects in the procured product or services within thirty (30) calendar days after such vulnerabilities and material defects become known to Contractor. The summary documentation shall include a description of each vulnerability and material defects and its potential impact, root cause, and recommended corrective actions, compensating security controls, mitigations, and/or procedural workarounds (e.g., monitoring).

(iii) Contractor shall disclose the existence of all known methods for bypassing computer authentication in the procured product or services, often referred to as backdoors, and provide written attestation that all such backdoors created by Contractor have been permanently remediated.

(iv) Contractor shall implement a vulnerability detection and remediation program consistent with industry standards (e.g., ISO-27417 Vulnerability Disclosure, NIST Cybersecurity Framework v1.1 Reference RS.AN-5, NIST Special Publication 800-53 Rev. 4 RA-5, SA-11, and SI-2, as may be amended.)

b. Disclosure of Vulnerabilities by Company: Whether or not publicly disclosed by Contractor and notwithstanding any other limitation in this Agreement, Company may disclose any Vulnerabilities, material defects, and/or other findings related to the products and services provided by Contractor to (a) the Electricity Information Sharing and Analysis Center ("E-ISAC"), the United States Cyber Emergency Response Team ("CERT"), or any equivalent U.S. governmental entity or program, (b) to any U.S. governmental entity when necessary to preserve the reliability of the BES as determined by Company in its sole discretion, or (c) any entity required by applicable law.

6. Hardware, Firmware, Software, and Patch Integrity and Authenticity.

a. Contractor shall establish, document, and implement risk management practices for supply chain delivery of hardware, software (including patches), and firmware provided under this Agreement. Contractor shall provide documentation on its: chain-of-custody practices, inventory management program (including the location and protection of spare parts), information protection practices, integrity management program for components provided by sub-suppliers, instructions on how to request replacement parts, and commitment to ensure that for one year, spare parts shall be made available by Contractor. Contractor shall provide Company access to inspect all of the Policies and Procedures described in this section.

b. Contractor shall specify how digital delivery for procured products (*e.g.*, software and data) including patches will be validated and monitored to ensure the digital delivery remains as specified. If Company deems that it is warranted, Contractor shall apply encryption to protect procured products throughout the delivery process.

c. If Contractor provides software or patches to Company, Contractor shall publish or provide a hash conforming to the Federal Information Processing Standard (FIPS) Security Requirements for Cryptographic Modules (FIPS 140-2) or similar standard information on the software and patches to enable Company to use the hash value as a checksum to independently verify the integrity of the software and patches.

d. Contractor shall identify or provide Company with a method to identify the country (or countries) of origin of the procured Contractor product and its components (including hardware, software, and firmware). Contractor will identify the countries where the development, manufacturing, maintenance, and service for the Contractor product are provided. Contractor will notify Company of changes in the list of countries where product maintenance or other services are provided in support of the procured Contractor product. This notification shall occur 180 days prior to initiating a change in the list of countries.

e. Contractor shall provide a software bill of materials for procured (including licensed) products consisting of a list of components and associated metadata that make up a component.

f. Contractor shall use or arrange for the use of trusted channels to ship procured products, such as U.S. registered mail and/or tamper-evident packaging for physical deliveries.

g. Contractor shall demonstrate a capability for detecting unauthorized access throughout the delivery process.

h. Contractor shall demonstrate chain-of-custody documentation for procured products as determined by Company in its sole discretion and require tamper-evident packaging for the delivery of this hardware.

7. Patching Governance.

a. Prior to the delivery of any products and/or services to Company or any connection of electronic devices, assets or equipment to Company's electronic equipment, Contractor shall provide documentation regarding its patch management and vulnerability management/mitigation programs and update process (including third-party hardware, software, and firmware) for products, services, and any electronic device, asset, or equipment required by Contractor to be connected to the assets of Company during the provision of products and services under this Agreement. This documentation shall include information regarding:

i. the resources and technical capabilities to sustain this program and process such as Contractor's method or recommendation for how the integrity of a patch is validated by Company; and

ii. Contractor's approach and capability to remediate newly reported zero-day vulnerabilities for Contractor products.

b. Unless otherwise approved by the Company in writing, current or supported version of Contractor products and services supplied by Contractor shall not require the use of out-of-date, unsupported, or end-of-life version of third-party components (*e.g.*, Java, Flash, Web browser, etc.).

c. Contractor shall verify and provide documentation that procured products (including third-party hardware, software, firmware, and services) have appropriate updates and patches installed prior to delivery to Company.

d. In providing the products and services described in this Agreement, Contractor shall provide or arrange for the provision of appropriate software and firmware updates to remediate newly discovered vulnerabilities or weaknesses for Contractor products within 30 days. Updates to remediate critical vulnerabilities shall be provided within a shorter period than other updates, within seven (7) days. If updates cannot be made available by Contractor within these time periods, Contractor shall provide mitigations, methods of exploit detection, and/or workarounds within 3 days.

e. When third-party hardware, software (including open-source software), and firmware is provided by Contractor to Company, Contractor shall provide or arrange for the provision of appropriate hardware, software, and/or firmware updates to remediate newly discovered vulnerabilities or weaknesses, if applicable to the Company's use of the third-party product in its system environment, within 30 days of availability from the original supplier and/or patching source. Updates to remediate critical vulnerabilities applicable to the Contractor's use of the third-party product in its system environment shall be provided within a shorter period than other updates, within thirty (30) days of availability from the original supplier and/or patching source. If applicable third-party updates cannot be integrated, tested and made available by Contractor within these time periods, Contractor shall provide or arrange for the provision of recommended mitigations and/or workarounds to the extent possible within 30 days.

8. Viruses, Firmware and Malware.

a. Contractor will use reasonable efforts to investigate whether computer viruses or malware are present in any software or patches before providing such software or patches to Company. To the extent Contractor is supplying third-party software or patches, Contractor will use reasonable effort to ensure the third-party investigates whether computer viruses or malware are present in any software or patches providing them to Company or installing them on Company's information networks, computer systems, and information systems.

b. Contractor warrants that it has no knowledge of any computer viruses or malware coded or introduced into any software or patches, and Contractor will not insert any code which would have the effect of disabling or otherwise shutting down all or a portion of such software or damaging information or functionality. To the extent Contractor is supplying third-party software or patches, Contractor will use reasonable efforts to ensure the third-party will not insert any code which would have the effect of disabling or otherwise shutting down all or a portion of such software or damaging information or functionality.

c. When install files, scripts, firmware, or other Contractor-delivered software solutions (including third-party install files, scripts, firmware, or other software) are flagged as malicious, infected, or suspicious by an anti-virus vendor, Contractor must provide or arrange for the provision of technical justification as to why the "false positive" hit has taken place to ensure their code's supply chain has not been compromised.

d. If a virus or other malware is found to have been coded or otherwise introduced as a direct result of Contractor's breach of its obligations under this Agreement, Contractor shall upon written request by Company and at Contractor's own cost:

  (i) Take all necessary remedial action and provide assistance to Company to eliminate the virus or other malware throughout Company's information networks, computer systems, and information systems; and

  (ii) If the virus or other malware causes a loss of operational efficiency or any loss of data:

    (a) where Contractor is obligated under this Agreement to back up such data, take all steps necessary and provide all assistance required by Company and its affiliates, or

    (b) where Contractor is not obligated under this Agreement to back up such data, use commercially reasonable efforts, in each case to mitigate the loss of or damage to such data and to restore the efficiency of such data.

9. <u>End of Life Operating Systems</u>:

  a. Contractor-delivered solutions will not be required to reside on end-of-life operating systems, or any operating system that will go end-of-life six (6) months from the date of installation.

  b. Contractor solutions will support the latest versions of operating systems on which Contractor-provided software functions within twenty-four (24) months from official public release of that operating system version.

10. <u>Cryptographic Requirements</u>:

  a. Contractor shall document how the cryptographic system supporting the Contractor's products and/or services procured under this agreement protects the confidentiality, data integrity, authentication, and non-repudiation of devices and data flows in the underlying system. This documentation shall include, but not be limited to, the following:

    (i) The cryptographic methods (hash functions, symmetric key algorithms, or asymmetric key algorithms) and primitives (*e.g.*, Secure Hash Algorithm [SHA]- 256, Advanced Encryption Standard [AES]-128, RSA, and Digital Signature Algorithm [DSA]-2048) that are implemented in the system, and how these methods are to be implemented.

    (ii) The preoperational and operational phases of key establishment, deployment, ongoing validation, and revocation.

  b. Contractor will use only "approved" cryptographic methods as defined in the FIPS 140- 2 Standard when enabling encryption on its products.

  c. Contractor shall provide or arrange for the provision of an automated remote key-establishment (update) method that protects the confidentiality and integrity of the cryptographic keys.

  d. Contractor shall ensure that:

    (i) The system implementation includes the capability for configurable cryptoperiods (the life span of cryptographic key usage) in accordance with the Suggested Cryptoperiods for Key Types found in Table 1 of NIST 800-57 Part 1, as may be amended.

    (ii) The key update method supports remote re-keying of all devices every year as part of normal system operations.

(iii) Emergency re-keying of all devices can be remotely performed within 30 days.

e. Contractor shall provide or arrange for the provision of a method for updating cryptographic primitives or algorithms.

11. Remote Access. Contractor shall coordinate with Company on all remote access to Company's systems and networks, regardless of interactivity, and shall comply with any controls for interactive remote access and system-to-system remote access sessions requested by Company.

   a. Controls for Remote Access: Contractors that directly, or through any of their affiliates, subcontractors or service providers, connect to Company's systems or networks agree to the additional following protective measures:

      i. Contractor will not access, and will not permit any other person or entity to access, Company's systems or networks without Company's authorization and any such actual or attempted access will be consistent with any such authorization.

      ii. Contractor shall implement processes designed to protect credentials as they travel throughout the network and shall ensure that network devices have encryption enabled for network authentication to prevent possible exposure of credentials.

      iii. Contractor shall ensure Contractor Personnel do not use any virtual private network or other device to simultaneously connect machines on any Company system or network to any machines on any Contractor or third-party systems, without

         (a) using only a remote access method consistent with Company's remote access control policies,

         (b) providing Company with the full name of each individual who uses any such remote access method and the phone number and email address at which the individual may be reached while using the remote access method, and

         (c) ensuring that any computer used by Contractor Personnel to remotely access any Company system or network will not simultaneously access the Internet or any other third-party system or network while logged on to Company systems or networks.

      iv. Contractor shall ensure Contractor personnel accessing Company networks are uniquely identified and that accounts are not shared between Contractor personnel.

12. Contractor Cybersecurity Policy.
Contractor will provide to Company upon request the Contractor's cybersecurity policy which shall be consistent with industry standard practices (e.g., NIST Special Publication 800-53 (Rev. 4) as may be amended). Contractor will implement and comply with its established cybersecurity policy.
Any changes to Contractor's cybersecurity policy as applied to products and services provided to Company under this Agreement and Company Information shall not decrease the protections afforded to Company or Company Information and any material changes shall be communicated to Company by Contractor prior to implementation.

13. Return or Destruction of Company Information.

Upon completion of the delivery of the products and services to be provided under this Agreement, or at any time upon Company's request, Contractor will return to Company all hardware and removable media provided by Company containing Company Information. Company Information in such returned hardware and removable media shall not be removed or altered in any way. The hardware should be physically sealed and returned via a bonded courier or as otherwise directed by Company. If the hardware or removable media containing Company Information is owned by Contractor or a third-party, a notarized statement detailing the destruction method used and the data sets involved, the date of destruction, and the entity or individual who performed the destruction will be sent to a designated Company security representative within thirty (30) calendar days after completion of the delivery of the products and services to be provided under this

Agreement, or at any time upon Company's request. Contractor's destruction or erasure of Company Information pursuant to this Section shall be in compliance with best industry practices (*e.g.*, Department of Defense 5220-22-M Standard, as may be amended).

Notwithstanding the foregoing, Company agrees that Contractor shall not be required to return to Company, or destroy, copies of Company Information that (A) reside on Contractor's backup, disaster recovery or business continuity systems, or (B) that Contractor is obligated by applicable law and/or governmental regulations to retain. Contractor agrees that, following its receipt of the Request, it shall neither retrieve nor use Company Information for any purpose other than that specified in clause (B) above.

14. <u>Audit Rights.</u>
Upon request, Contractor shall provide to Company a copy of the Contractor's policies, procedures, evidence and independent audit report summaries that are part of a cyber security framework (e.g. ISO-27001, SOC2). Company or its third-party designee may, but is not obligated to, perform audits and security tests of Contractor's IT or systems environment and procedural controls to determine Contractor's compliance of identified control gap(s) with the system, network, data, and information security requirements of this Agreement . Company audits of the Contractor system shall be done with at least 30 days advance notice. These audits and tests may include coordinated security tests as mutually agreed to not unduly affect Contractor operations, interviews of relevant personnel, review of documentation, and technical inspection of systems and networks as they relate to the receipt, maintenance, use, retention, and authorized destruction of Company Information. Contractor shall provide all information reasonably requested by Company in connection with any such audits and shall provide reasonable access and assistance to Company upon request. Contractor will comply, within reasonable timeframes at its own cost and expense, with all reasonable recommendations that result from such inspections, tests, and audits. Company reserves the right to view, upon request, any original security reports that Contractor has undertaken or commissioned to assess Contractor's own network security. If requested, copies of these reports will be sent via bonded courier to Company security contact. Contractor will notify Company of any such security reports or similar assessments once they have been completed. Any regulators of Company or its affiliates shall have the same rights of audit as described herein upon request.
15. <u>Regulatory Examinations</u>.
Contractor agrees that any regulator or other governmental entity with jurisdiction over Company and its affiliates may examine Contractor's activities relating to the performance of its obligations under this Agreement to the extent such authority is granted to such entities under the law. Contractor shall promptly cooperate with and provide all information reasonably requested by the regulator or other governmental entity in connection with any such examination and provide reasonable assistance and access to all equipment, records, networks, and systems reasonably requested by the regulator or other governmental entity. Contractor agrees to comply with all reasonable recommendations that result from such regulatory examinations within reasonable timeframes.

ATTACHMENT 3 - SELLER'S EXCEPTIONS AND CLARIFICATIONS

Technical Exceptions	
ALL fields of the datasheet must be fully completed in order for Bidder to be properly evaluated and receive full consideration from the Company. Supplemental information may be provided by Bidder but may not initially be reviewed during the first phase of the	
Does Bidder take exception to any technical requirement of the subject RFP Documents?	
(If Bidder takes exception to any of the Technical Specifications of the subject RFP Documents, each exception shall be identified and detailed in the below individual sections)	
1	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
2	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
3	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
4	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
5	
RFP Section Reference	
Original RFP Language	

Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	

6	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
7	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
8	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
9	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
10	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	

11	
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Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
12	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
13	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
14	
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Describe Price Impact (if applicable)	
15	
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Reason for Exception	
Describe Price Impact (if applicable)	

16	
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Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
18	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
19	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	
20	
RFP Section Reference	
Original RFP Language	
Describe Technical Exception	
Reason for Exception	
Describe Price Impact (if applicable)	

ATTACHMENT 4 - COMMERCIAL QUESTIONNAIRE

References and Experience

Please provide a minimum of 3 utility references with relevant project experience or top clients or projects in excess of $ 1,000,000.00 per year.

Reference #1	
Client Name	
Client Contact Name	
Client Location	
Most Recent Annual Sales to Client	
Specified Year of Sales	
Vendor Engagement Lead Name	
Vendor Engagement Lead Location	
Vendor Technical Lead Name	
Vendor Technical Lead Location	
Brief Project Description	
Reference #2	
Client Name	
Client Contact Name	
Client Location	
Most Recent Annual Sales to Client	
Specified Year of Sales	
Vendor Engagement Lead Name	
Vendor Engagement Lead Location	
Vendor Technical Lead Name	
Vendor Technical Lead Location	
Brief Project Description	
Reference #3	
Client Name	
Client Contact Name	
Client Location	
Most Recent Annual Sales to Client	
Specified Year of Sales	
Vendor Engagement Lead Name	
Vendor Engagement Lead Location	

Vendor Technical Lead Name	
Vendor Technical Lead Location	
Brief Project Description	

ATTACHMENT 5 - TECHNICAL QUESTIONNAIRE

Public Service Company of New Mexico (PNM) is seeking an Advanced Metering Infrastructure (AMI) solution as a foundational component of Grid Modernization investments. PNM is beginning to implement time of use (TOU) rate structures including whole house electric vehicle (WHEV) and time of day (TOD) tariffs. Additionally, PNM anticipates continued distributed energy resource (DER) adoption by customers and needs a capable and extensible AMI solution that can evolve to meet customer program needs to support customer TOU, demand response (DR), DER, and electric vehicle (EV) tariffs and programs. Because AMI infrastructure will be in place for 15-20+ years, the system must also support forward looking advanced applications including the potential for future non-wired alternatives to meet distribution grid needs with grid services provided by DER, wholesale energy market participation by customer DER, and even a transactive energy marketplace for DER to provide distribution grid services.

With this “future proof” approach in mind, please respond to the technical questionnaire below while highlighting the proposed solution attributes that support this forward looking vision. For example, AMI deployments in other states have continued to be hampered by insufficient meter memory to support firmware upgrades, transition to the Wi-SUN standard, and evolve from 1-hour interval data for initial AMI deployments (2008-11) to 15-minute interval data in the 2010s and now to 5-minute meter data intervals to support energy market participation by DER.[1] Concurrently, there is increasing need for more interval meter data, including active energy (kWh), active power (kW), current (A), voltage (V), power factor, and reactive power (kVAR). PNM is including a white paper by EnerNex illustrating the need for firmware memory to have only 11% of the firmware memory utilized by the initial firmware installation.[2]

[1] See Federal Energy Regulatory Commission (FERC) Orders 719, 745, 841 and 2222.
[2] Excerpt from Embedded Device Firmware Memory Sizing (Rule of 9): Since the assumed maximum size for new firmware versions with additional features is 3x of the original firmware size and 3x memory is required during a firmware upgrade, 3x * 3x memory is needed = 9x. © 2020 EnerNex, LLC

System Requirements

Respondents must reply to each question/requirement. State if your proposed solution meets the requirement and if so, describe how. If not, describe why this requirement is not supported.

1. Communications

1.1. Does the AMI communications Neighborhood Area Network (NAN) use a high-speed RF mesh Frequency Hopping Spread Spectrum (FHSS) technology (IEEE 802.15.4g) using the Wi-SUN communication protocol? If not, please describe the technology used and the plans (if any) to move to a solution that utilizes Wi-SUN protocol in the future without any need for hardware upgrades (i.e., over the air software/firmware upgrade). Please provide estimated bandwidth and throughput of the communication system.

1.2. For areas where a mesh network is not viable, is there a cellular LTE meter option?

1.2.1. What cellular carriers are compatible with the LTE meter option?

1.2.2. Are private LTE options supported? If so, please describe private LTE options

1.2.3. If PNM adopts private LTE in the future, what steps would be needed to transition the AMI system from commercial carrier to private LTE

1.3. Is there an available “collector meter” option where the meter has an LTE modem and acts as a mesh gateway?

1.4. Is the NAN capable of supporting multiple logical Internet Protocol version 6 (IPv6) networks using the Wi-SUN communication protocol?

1.5. Is the system scalable to accommodate the easy addition of additional access points (Collectors, Routers, Gateways) to increase data throughput and decrease latency?

1.6. Does the NAN operate on a licensed or unlicensed frequency spectrum? The preferred solution will operate in in the unlicensed ISM frequency band of 902 - 928 MHz to help guard against unexpected future FCC band reallocations. Please describe the advantages of using the vendors proposed spectrum if it does not operate in an unlicensed spectrum.

1.7. Do the NAN radio devices (i.e., meters, routers, collectors, and repeaters) meet FCC requirements?

1.8. Has the vendor (or their supplier) obtained FCC approval certification for the NAN network radio devices?

1.9. Is the AMI network self-configuring and self-healing (in the event of degrading RF communications, failed router, or a failed collector)? Please describe the system’s ability to recover from such incidents.

1.10. Is your system considered a proactive or reactive mesh network? Describe what this means with regard to providing reliable path routing. Specifically, how is the path from Collector to end device determined?

1.11. Does the network provide data backup in the field at more than one location, and provide protection against communications failures if the loss of any network access points occurs?

1.12. What telecommunication network pathways are compatible to be utilized as the Field Area Network (FAN) backhaul for the NAN mesh network at the collector, field area router and/or gateway?

1.12.1. LTE Modem? Both carrier and private LTE?

1.12.2. Meter with an LTE modem utilized as a collector/gateway communicating with the NAN?

1.12.3. Licensed 900 MHz radio

1.12.4. Connection to the Wide Area Network at the substation?

1.12.4.1. Fiber with Internet Protocol (MPLS) with possible Dense Wave-length Division Multiplexing (DWDM)

1.12.4.2. Microwave - Please specify (1) spread spectrum or Licensed; (2) OTN, IP, or Time Division Multiplexing transport connections

1.12.5. What other NAN to FAN backhaul communications are supported?

1.13. How many network interface cards can be utilized in the collector, field area router and/or gateway? For example, can it connect to the NAN and have both a commercial carrier LTE and private LTE card?

1.14. Does the system provide a communications hierarchy to prioritize system events such as on-request meter readings, outage management, and alarms?

1.15. What percentage of the network communications is used as overhead?

1.16. What collector/gateway/router solution is proposed in areas that have underground electric infrastructure (no poles)?

1.17. What is the average number of meters per collector and per router in the proposed system?

1.18. During the normal mode of operation, is data read from the end device, such that the end device responds to a table read request (polled), or does the end device push data to the Collector?

1.18.1. For push solutions, is this a configurable schedule?

1.18.2. Can this be configured on a per end device basis?

1.19. How is network bandwidth and throughput affected by airtime congestion when performing a scheduled register read, a scheduled load profile read, a broadcast time synchronization, an on-request read and a firmware update? Please provide examples for each.

1.20. Does the system provide the ability to configure the timeframe desired for energy usage readings (e.g., read the meters between 1am and 4am)?

1.21. Describe how the system provides on-demand readings and other associated information.

1.22. Describe how the system provides broadcast messaging and endpoint grouping capabilities.

1.23. Describe the system's network performance reporting capability, including network Schedule Metrics, System LAN Metrics, LAN hop levels and paths, and WAN Metrics as well as how it identifies non-communicating meters or unknown devices on the LAN.

1.24. How often does the interval meter data get collected/transmitted to the meter head end system and meter data management system?

1.25. Describe the system's ability to provide for optional pre-paid metering plans. Describe any installed systems for your proposed solution where there is a pre-pay option.

1.26. Describe how the proposed solution includes open architecture principles that will provide flexibility in the future.

1.27. Describe the cyber security approach used by the communication system.

1.28. Describe the communication system's capability to provide distribution system monitoring and end-point information from devices such as distribution transformers and other distribution equipment as well as capabilities to support Distribution Automation (DA).

2. Metering Specifications

ANSI Specification and other Regulatory Requirements

2.1. Does your solution meet all relevant and most recent ANSI specifications and other regulatory requirements including but not limited to ANSI C12.1, ANSI C12.10, ANSI C12.18, ANSI C12.19, ANSI C12.20, ANSI C12.21, and ANSI C12.22?

Meter

2.2. What metrology elements are monitored by the meter and at what data resolution in terms of time (e.g., hours, minutes, seconds, subseconds, etc.)?

2.2.1. How is this metrology data processed to derive the interval meter data values (Active Energy, Active Power, Current, Voltage, Power Factor, Reactive Power, Frequency, Internal Temperature)

2.2.2. How is this metrology data processed to initiate alarms and notifications?

2.3. Are the meters self-registering to the AMI network?

2.3.1. Describe the process of how a meter is registered on the network.

2.3.2. How long does the meter registration process take to complete?

2.4. Do metering endpoints provide fully integrated metrology and radio communications integrated with the meter board?

2.5. Does the meter have an option for a Global Position System (GPS) chip? If so, how is that utilized (theft detection, time synchronization, etc.)?

2.6. Describe how meter registers are utilized on the meter given the transition from register read billing to interval data billing where the PNM Banner CIS billing engine requests billing determinants from the MDMS to calculate bills based on the (5-minute) interval data.

2.6.1. How many registers are available?

2.6.2. What metrology values can be recorded on the registers?

2.6.3. What calculation (formula channels) are available in the meter? How is the calculation performed?

2.7. Is there a process for field service personnel to access the meter (e.g., KYZ pulse output, optical probe, wirelessly)?

2.7.1. What toolset (devices and software) are required for field service personnel to access the meter?

2.7.2. What is the process for feeding the manually retrieved data to the MDMS?

2.8. For single-phase meters, how many channels are available to record and transmit interval data?

2.9. For polyphase meters, how many channels are available to record and transmit interval data?

2.10. To what degree is the time interval for each data type configurable? List the configurable intervals available.

2.11. Are single phase AMI meters capable of measuring and communicating the metrology interval values below?

Meter Data	Unit	Interval
Active Energy (delivered)	kWh	5-minute
Active Energy (received)	kWh	5-minute
Active Energy (net)	kWh	5-minute
Active Power (maximum)	kW	5-minute
Active Power (average)	kW	5-minute
Active Power (minimum)	kW	5-minute
Current (maximum)	A	5-minute
Current (average)	A	5-minute
Current (minimum)	A	5-minute
Voltage (maximum)	V	5-minute
Voltage (average)	V	5-minute
Voltage (minimum)	V	5-minute
Average Power Factor		5-minute
Reactive Power (received)	kVAR	5-minute
Reactive Power (delivered)	kVAR	5-minute
Frequency	Hz	5-minute
Internal Temperature	C	5-minute

2.11.1. PNM understands that there is a trade-off for the number of registers/channels of data recorded and the number of days for which that memory can be retained in the meter. PNM has not settled on a specific requirement, but it expects it to be in the range of 30-45 days. Describe your implementation experience with sizing metrology payloads with available memory.

2.11.2. What are the size options for physical memory used to store metered data for the meter models and form factors that you are proposing?

2.11.3. How many days of data storage for the available set of metrological values identified in the table above can be stored in the single phase meter memory? For the following value sets at 5 minutes:

2.11.3.1. Active Energy (delivered & received); Active Energy (net); Active Power (max); Voltage (avg);

2.11.3.2. Active Energy (delivered & received); Active Energy (net); Active Power (max & avg); Voltage (max & avg); Frequency

2.11.3.3. Active Energy (delivered & received); Active Energy (net); Active Power (max & avg); Current (avg); Reactive Power (delivered & received); Voltage (max & avg); Frequency

2.11.4. Same as 2.9.3 but at a 15-minute interval.

2.11.5. If the meter data is not retrieved successfully, describe the system process for retrieving the data and at what point a field service call would be required to diagnose the issue.

2.11.6. Given the metrology data payload from the table above, what percentage of meters will be read on a daily basis thereby forming the basis for key performance indicator (KPI)?

2.11.6.1. Please describe the automated recovery process for missed meter reads during the normal (non-outage) conditions.

2.11.6.2. What is the related KPI for gathering the missing meter reads?

2.11.7. Given the metrology data payload from the table above, what is the recommended ratio for meter to collector?

2.11.8. Can the meter be remotely programmed and configured to change which metrology values are recorded? If yes, are there any limitations to this capability?

2.11.9. Can the meter be remotely programmed and configured to change which alarms and notifications are sent?

2.12. Are poly phase AMI meters capable of measuring and communicating the metrology interval values per phase (other than temperature) below.

Meter Data	Unit	Interval
Active Energy (delivered)	kWh	5-minute
Active Energy (received)	kWh	5-minute
Active Energy (net)	kWh	5-minute
Active Power (maximum)	kW	5-minute
Active Power (average)	kW	5-minute
Active Power (minimum)	kW	5-minute
Current (maximum)	A	5-minute
Current (average)	A	5-minute
Current (minimum)	A	5-minute
Voltage (maximum)	V	5-minute
Voltage (average)	V	5-minute
Voltage (minimum)	V	5-minute

Average Power Factor		5-minute
Reactive Power (received)	kVAR	5-minute
Reactive Power (delivered)	kVAR	5-minute
Frequency	Hz	5-minute
Internal Temperature	C	5-minute

2.12.1. How many days of data storage for the available set of metrological values identified in the table above can be stored in the single phase meter memory ? For the following value sets at 5 minutes:

2.12.1.1. Active Energy (delivered & received); Active Energy (net); Active Power (max); Voltage (avg);

2.12.1.2. Active Energy (delivered & received); Active Energy (net); Active Power (max & avg); Voltage (max & avg); Frequency

2.12.1.3. Active Energy (delivered & received); Active Energy (net); Active Power (max & avg); Current (avg); Reactive Power (delivered & received); Voltage (max & avg); Frequency

2.12.2. Same as 2.10.1but at a 15-minute interval.

2.12.3. If the meter data is not retrieved successfully, describe the system process for retrieving the data and at what point a field service call would be required to diagnose the issue.

2.12.4. Given the metrology data payload from the table above, what percentage of meters will be read on a daily basis thereby forming the basis for key performance indicator (KPI)?

2.12.4.1. What is the related KPI for gathering the missing meter reads?

2.12.5. Given the metrology data payload from the table above, what is the recommended ratio for meter to collector?

2.12.6. Can the meter be remotely programmed and configured to change which metrology values are recorded? If yes, are there any limitations to this capability?

2.13. Can the meter be remotely programmed and configured to change which alarms and notifications are sent? Describe how the system provides daily peak demand (kW). Does your solution provide (and do you recommend) capturing peak demand for each interval and using the MDMS to determine the daily peak demand from those recorded? (e.g., The MDMS looks at the 96 fifteen minute intervals and then indicates which is the highest).

2.14. For the integrated radio, what is the

2.14.1. power output,

2.14.2. output power density, and

2.14.3. output power density based on 47 CFR1.1310 of?

2.15. Does the meter have high internal temperature alarm capability?

2.15.1. Please describe the capability and how the message is prioritized back to the AMI head end.

2.15.2. What other alarm capabilities does the meter have?

2.16. Describe how the meter can be remotely configurable.

2.16.1. What changes can be made (i.e., quantities metered, local display changes, load control schedule changes, demand limiting settings changes, register parameters)?

2.16.2. How long does it take for configuration changes to take affect for the meter population?

2.17. Does the meter have the capability to serve as an open application platform currently or is there a development path toward such capability? Please describe.

2.18. Does the AMI system provide meter voltage swell and sag alerts based on utility defined voltage thresholds?

2.19. Can the meter head end system or the MDMS relay the voltage swell and sag notifications to the PNM ACS Prism Distribution Management System (DMS)?

2.20. What is the expected latency in a meter detecting a voltage swell/sag event and the notification being relayed to the DMS?

2.21. Does the meter provide the capability of detecting load-side voltage?

2.21.1. Can the meter automatically open the service switch when there is load-side voltage during an outage?

2.21.2. Does the system prevent the reclosing of the service switch if load-side voltage is present?

2.21.3. If the service switch does open due to load side voltage during an outage, what is the process for closing the switch and reconnecting the customer to the grid after the power is restored?

2.22. PNM anticipates acquiring single phase meters with a remotely operated service control switch for the following use cases: a) disconnect for non-payment; b) customer move-in/move-out; c) customer pre-payment program. What other use cases is the vendor aware of?

2.22.1. Are the proposed single phase AMI meters available with an integrated connect/disconnect switch? What is the current rating?

2.23. Please describe the circumstances wherein a command issued from the CIS would bypass the MDMS and communicate directly with the head end.

2.24. PNM is aware that the latest generation of meters are capable of providing a platform that enables different applications to be installed on the meter to enable different functionality including edge computing.

2.24.1. Please describe the current capabilities for enabling meter applications and the associated edge computing functionality

2.24.2. Please describe the envisioned (roadmapped) capabilities for meter applications and the associated edge computing functionality and an associated timeline

2.24.3. What considerations should be taken into account to ensure that meters installed in the next several years will still be capable of installing and updating the meter applications during their useful life?

2.25. What additional functionality and capabilities are you developing for future meter models and/or meter upgrades?

2.26. What is the designed lifecycle and useful life timeframe for the proposed meter(s)?

2.27. What data or information can be displayed on the meter itself? Is there a limit to the number of screens that are cycled through on the display?

3. Collector and Field Area Router, Gateway, and Repeater Specifications

3.1. Is the proposed telecommunications equipment (collector, field area router, gateway, repeater) Wi-SUN certified (https://wi-sun.org/certified-products-list/)?

3.2. Describe the process used to upgrade firmware in the collector, field area router, gateway, and/or repeater. Identify if the upgrade can be done remotely and locally.

3.2.1. Are there any issues or concerns regarding the collector, field area router, gateway, or repeater being able to accommodate over the air upgrades to future releases of the Wi-SUN standard?

3.3. Describe what changes can be made remotely to the telecommunications equipment.

3.4. Provide as part of the submission, mounting specifications and physical dimensions for any collector equipment, gateways, field area routers, range extenders, etc.

3.5. What is the power output, output power density, and output power density based on 47 CFR1.1310 of the collectors, routers, and repeaters?

3.6. Is there an available meter option for the NAN mesh gateway to be under glass in the meter which utilizes LTE to communicate with the head end system?

4. Home Area Network (HAN), Demand Response (DR) & Distributed Energy Resource (DER)

PNM is aware that previous AMI installations have typically used the ZigBee Smart Energy Profile (SEP) version 1.x protocol to enable HAN communications to customer devices and that the customer adoption and utilization of for those devices has been low. PNM still believes that there are use cases for HAN device enablement including: a) traditional customer usage visibility scenarios; b) Smart inverter communication with the meter to monitor energy export, etc.; c) high resolution energy data for disaggregation (e.g., appliance identification); d) customer DR and DER program performance monitoring and assessment during a dispatch event.

4.1. What are your capabilities for supporting these use case scenarios?

4.2. What are your plans for supporting these use case scenarios?

4.3. Describe the system's ability to interface with a Home Area Network (HAN) utilizing

4.3.1. Physical telecommunication standards

4.3.1.1. Wi-Fi (IEEE 802.11) including specifying the Wi-Fi generation (a, b, g, n, ac, ax/ Wi-Fi 6)

4.3.1.2. ZigBee

4.3.1.3. IEEE 802.15.1 Bluetooth

4.3.1.4. Z-Wave

4.3.1.5. IEEE 1901 Home Plug

4.3.1.6. Ethernet

4.3.1.7. Others?

4.3.2. Messaging / Application Layer protocol standards (please identify the associated compatible physical telecommunication standard)

4.3.2.1. ZigBee Smart Energy Profile (SEP) version 1.x

4.3.2.2. SEP 2.0

4.3.2.3. IEEE 2030.5

4.3.2.4. Wi-SUN HAN protocol (https://wi-sun.org/han-certified-products/)

4.3.2.5. ANSI C12.19

4.3.2.6. OpenADR

4.3.2.7. Thread

4.3.2.8. Matter

4.3.2.9. Others?

4.4. Can the HAN communications be remotely enabled/disabled as customers opt-in to utilizing that meter interface?

4.5. Is the meter and system capable of utilizing the HAN interface with the advanced meter to:

4.5.1. Interface with customer DR, load control, or DER devices?

4.5.2. Interface with building or energy management control systems?

4.5.3. Interface with advanced inverters (IEEE 1547-2018)

If so, please detail the HAN interface in terms of technology (physical network and messaging protocol options) and security.

4.6. Do any of your utility clients utilize the HAN interface with the advanced meter to:

4.6.1. Interface with customer DR, load control, or DER devices?

4.6.2. Interface with building or energy management control systems?

4.6.3. Interface with advanced inverters (IEEE 1547-2018)

If so, please provide the utility client reference and detail the HAN interface in terms of technology (network and messaging protocol), security, and customer interface / program structure

4.7. Can the AMI system support a pre-payment option for customers?

4.7.1. If so, describe such capabilities.

4.7.2. If so, is the system capable of working with a third party pre-payment vendor? If so, please name the vendor(s).

4.8. Describe any metering capability for load limiting.

4.9. Describe any additional metering and MDMS capabilities and support for DER including capabilities for DR, load control and DER monitoring and control.

4.10. Describe any additional metering and MDMS capabilities and support for customer sited energy storage as a DER.

4.11. Describe any additional metering and MDMS capabilities and support for Electric Vehicle charging and related tariffs and programs.

5. Network Management System (head-end) Requirements

Head-End Hardware Requirements

5.1. Identify the server and other hardware requirements and specifications to ensure a robust operating platform for the AMI head-end systems given the interval meter data from the tables above and requirements for future software and firmware upgrades.

Head-End Software Requirements

5.2. Identify the software architecture and the ability to integrate with existing PNM enterprise systems.

5.2.1. Tibco Integration Bus

5.2.2. PNM Banner Customer Information System (CIS)

5.2.3. ACS Prism Outage Management System (OMS)

5.2.4. ACS Prism Distribution Management System (DMS) and Distribution SCADA.

5.2.5. PNM ESRI Arc FM Geographic Information System (GIS)

5.2.6. OSIsoft PI data warehouse

5.3. Does the head end system utilize open standards such as SOAP, XML, MultiSpeak, and/or Common Information Model (CIM) for integration to PNM the utility applications listed above? Please specify the standards utilized for the different systems interfaces.

5.4. What licenses are required for the software? Include the price of all licenses in the pricing section with pricing methodology (e.g., per server, enterprise, per user, etc.).

5.4.1. Provide annual maintenance and licensing costs for AMI head end software in the pricing section.

5.4.2. What options are there for the utility to receive software support (upgrades, service level agreements, etc.)?

5.5. What is your envisioned release schedule for patches, hot fixes, and upgrades?

5.5.1. How long is a software version typically supported?

5.6. What APIs are available for the head end system?

System Integration

5.7. PNM utilizes a Tibco integration bus to facilitate data exchange between IT/OT systems. Has your system (head end and MDMS) interfaced with other systems via Tibco?

5.8. Please describe the systems integrations between the head end system and MDMS and other systems including:

5.8.1. Proprietary Customer Information Systems (CIS) like PNM Banner

5.8.2. Interactive Voice Response (IVR)

5.8.3. Pre-Pay systems or service providers

5.8.4. Advanced Distribution Management System (ADMS) applications including Distribution Management System (DMS), Outage Management System (OMS), and Distributed Energy Resource Management System (DERMS)

Outage Management

5.9. Describe the capabilities of the proposed system to manage outage notifications.

5.10. Does the AMI system provide meter "last-gasp" outage detection and restoration management?

5.11. What open standards are utilized to facilitate the AMI to OMS integration?

5.12. Do the Meter Head End system or the MDMS have configurable "pre-processing"/filtering capabilities to help identify and validate the customers affected by an outage (fault location) before sending outage data to the ACS Prism OMS? If so, please describe the "pre-processing" capabilities.

5.13. Can the system provide power status checks (i.e., confirm power at specific meters)?

5.13.1. Does it identify per phase outages or report partial voltage?

5.14. How is the system notified of a restoration of power? Do the meters automatically provide notification?

5.15. What provisions are there for identifying and filtering a momentary outage and avoiding a service call for restoration.

5.15.1. What is the "last gasp" period for the meter?

5.15.2. What filtering (if any) is performed to identify momentary outages and what system performs that filtering?

5.15.3. What provisions are there for tracking momentary outage data?

5.16. Please describe how the AMI outage notifications would be relayed to the PNM ACS Prism Outage Management System (OMS). Does your solution prefer to have outage event messages sent from the Head End system or the MDMS?

Tools

5.17. Describe any tools available in the proposed AMI system to aid in network analysis, outage management and troubleshooting.

5.18. What tools are available to capture and validate meter location data (longitude / latitude) during meter installation?

5.19. What tools are available to capture and validate meter to service transformer mapping?

On-Request Reads

5.20. Is the head end system capable of supporting on-request reads? How is this initiated?

5.21. How would an On-Request read be initiated by a CIS or other system?

5.22. Describe how the system prioritizes scheduled and on–request reads.

Remote Disconnect

5.23. Describe how your entire system performs a remote disconnection/reconnection including interactions by the CIS, MDMS, head end, and meter.

5.23.1. How is this initiated?

5.23.2. Can the remote disconnect or reconnect be scheduled (and cancelled) per business rules? If so, where does the schedule reside.

5.24. Can the customer service supply and any customer distributed generation or energy storage be metered separately by the same meter?

5.25. Can the customer DER (e.g., energy storage, distributed generation) energy export be disconnected or curtailed independently of the customer electricity service?

5.26. How does the AMI system provide connect / disconnect verification after operation?

5.26.1. What is the connect / disconnect exception process or message?

5.27. Does the AMI System support a process to limit control of the disconnect switch to authorized employees or system application service IDs only?

Time Synchronization

5.28. Describe how the proposed solution manages time synchronization at the head-end, collector, router, and AMI meters.

5.29. How often are components throughout the AMI system time synchronized?

Firmware Upgrades

5.30. Describe the proposed system's ability to remotely upgrade firmware.

5.31. Describe the process for remotely upgrading firmware.

5.32. Is the firmware for meters, collectors, gateways, routers, and repeaters remotely and locally upgradable?

5.33. How long does it take (on average) for an over-the-air firmware upgrade to propagate to:

5.33.1. A single meter

5.33.2. The entire population of meters

5.33.3. Collectors

5.33.4. Gateways

5.33.5. Routers

5.33.6. Repeaters

5.34. Describe the process for recovering from firmware upgrade exceptions/failures.

5.35. Can the firmware upgrades be performed via configurable sets? What types of sets (percent of population, geographic, meter type/form, circuit, transformer, etc.)?

5.36. Can the firmware upgrades be performed via a schedule? What types of schedules?

5.37. What is the expected increase in firmware size during the useful life of the meter?

5.38. Are there any issues or concerns regarding the meter being able to accommodate over the air upgrades to future releases of the Wi-SUN standard?

Tamper Detection

5.39. Describe the capabilities of the system to detect tampering at the meters (e.g., alarms for report Tilt, Loss of Power, Inverted Meters, etc.).

5.40. What type of events/situations will trigger a tamper notification in the head-end system, and how does the system reduce the risk of false alarms?

5.41. How does a utility business user receive notification of possible tampering?

Data Security

5.42. How does the head system support role-based security?

5.43. Does the system support single sign on for user authentication?

5.44. Describe the data security measures built into the system to protect data during transmission.

5.45. Describe the data security measures built into the system to protect data stored at the different points of the AMI network.

5.46. Describe the certification process for testing and validation of security patches and upgrades.

5.47. Describe the solution's key management process for cyber security.

5.48. Describe system encryption capabilities and where encryption is applied within the network (e.g., meter to router, router to collector, collector to head end).

5.48.1. Does the system use shared encryption keys?

5.48.2. Describe the process for encryption key management.

5.49. Describe what personally identifiable customer information (PII) is transmitted from meters to head end.

5.50. Describe any cyber security capabilities for communication into the HAN.

5.51. Describe if and how the head end system security can limit the ability for an authorized user to send mass remote disconnect commands.

5.51.1. How is the authorized user or business notified when the limit is exceeded?

5.52. Describe any capabilities of the system to detect unauthorized systems or devices added to the AMI network.

5.53. Describe any capabilities that can limit local device reconfiguration.

5.54. Describe any capabilities of the system to detect unauthorized firmware changes.

5.55. What is a typical security patch frequency and methodology for the items below:

5.55.1. AMI meters

5.55.2. Network routers

5.55.3. Network gateways

5.55.4. Network collectors

5.55.5. Network head end systems

5.55.6. Meter data management systems

5.56. Does your firmware upgrade process follow the requirements of the NEMA Smart Grid Standards Publication SG-AMI 1-2009?

Scalability

5.57. Describe how the system can accommodate growth in the number of connected devices.

5.58. Describe how the system can accommodate change in future requirements.

5.58.1. Describe your roadmap for future functionality and the system's ability to upgrade/expand for that future functionality.

5.58.2. How is the system designed to avoid obsolescence?

6. Meter Data Management System

6.1. Provide pricing in the pricing sheet for the following scenarios with respect to the deployment of the meter data management system. Please provide system costs, licensing costs, and on-going maintenance costs for each of the following:

6.1.1. Meter data management system hardware and software owned and operated by PNM at its own data center.

6.1.2. Meter data management system hardware and software owned by PNM and hosted and operated by the vendor in the vendor's data center.

6.1.3. Meter data management system hardware and software owned by the vendor in a vendor hosted solution.

6.2. For all hosted solutions (either PNM owned hardware/software or vendor owned hardware/software):

6.2.1. Requirement: Security Controls Framework - The service provider is required (as part of the RFP response) to identify the security controls framework and describe the implementation and enforcement of security controls based on one or more of industry-recognized frameworks, such as ISO 27001/27002, COBIT, and NIST. In addition, please provide a list additional regulatory standards implemented and enforced, such as PCI, HIPAA, or NERC CIP. The security control framework(s) provide the needed structure, detail and clarity on (but not limited to) information security and will normalize security expectations, taxonomy and terminology, and security measures implemented by service provider. A description of the implemented security control framework(s) is requested and will be used by PNMR to evaluate overall security risks associated with service provider.

6.2.2. Requirement: Audit of Controls as a Service Organization - The service provider is required (as part of the RFP response) to provide their most recent independent 3rd party Audit report of Controls as a Service Organization; relevant to Security, Availability, Processing Integrity, Confidentiality and Privacy. For example, the SOC 2 standard set forth by the American Institute of Certified Public Accountants. PNMR will use the Audit report findings, opinions, and assertions to help evaluate overall risks associated with service provider.

6.3. What database is utilized for the MDMS (e.g., Oracle, SQL, etc.)

6.3.1. Describe the required database maintenance and associated timeframes

6.4. What is your recommended approach for MDMS data management and data archiving?

6.5. Describe any MDMS APIs that are supported and how they are used

6.6. How do meters get validated in the system for their configuration? Can a meter be a billing meter (registers) and a load profile meter (channels)?

6.7. What is the process for adding, moving, or changing a meter?

6.8. Describe the process for meter configuration and reconfiguration?

6.9. How does the MDMS track the configuration of the meters through their lifecycle?

6.10. Can the meters be arbitrarily aggregated/grouped (ex. by circuit, account, region neighborhood, DER customer, etc.)? How is this accomplished?

6.10.1. Is there a limit to the number of groups that a meter can be assigned to?

6.11. What is the process for loading manual meter reads (both from advanced meters and legacy non-communicating meters) into the MDMS? Note that PNM uses FCS today and may continue to do so in the future.

6.12. How does the MDMS process moving a meter from one location and installing the same meter at another location?

6.13. Describe the verification, estimation, and error correction (VEE) process.

6.13.1. How is the VEE Configured?

6.13.2. Can VEE rule configurations be different for different classes of customers?

6.13.3. How are estimated interval values identified in the MDMS for missing interval data? What approaches or algorithms are available for estimation?

6.13.3.1. Are estimated values replaced with actual read values if the meter is read after the estimated value is generated?

6.13.3.2. Is there a mechanism for suspending the estimation process during storm outage conditions? Please describe the process or configuration.

6.13.4. What is the delay before data is validated? Does the validation require a full day of interval values to execute?

6.14. How many days of meter data does the MDMS…

6.14.1. keep in active memory?

6.14.2. support keeping in online storage?

6.14.3. support keeping in archival storage?

6.15. GUI/Usability

6.15.1. How are MDMS GUI screen layouts, workflow, alerts, menus, etc., designed to mirror business processes.

6.15.2. Please provide an example or process flow for how business rules that support the creation of data are integrated and logically flow within the MDMS GUI from one screen to the next.

6.15.3. Please provide an example or process flow for how business rules that support the updating of data are integrated and logically flow within the MDMS GUI from one screen to the next.

6.15.4. MDMS GUI access will be based on user role and profile and will control view/update access to MDMS data as well as access to functions and commands (e.g., ping meter, request on-demand read, issue on/off commands, retry commands, etc.).

6.15.4.1. Please describe the associated role based access.

6.15.4.2. Are MDMS users identified via a unique ID and support single sign-on?

6.15.5. Does MDMS display engineering units and unit type (e.g., kWh) whenever interval data is displayed?

6.15.6. Does the MDMS allow authorized users to customize their screen views and save customized settings for future sessions?

6.15.7. Please describe or illustrate the MDMS GUI design and capabilities with typical analyst tools requirements such as: help, notes, hot keys, graphs, and reports.

6.15.8. How does the MDMS GUI perform user input validation and reasonableness checking based on industry standards and user-defined rules (e.g., input sanitization, filtering, canonicalization, through use of regex, character escaping schemes)?

6.15.9. Does the MDMS prompt the user when exiting if edits have not been saved?

6.15.10. Does the MDMS shall warn the user prior to deleting any information from the system?

6.15.11. Does the MDMS GUI provide a drop-down selection list for specific fields? Please provide illustrations.

6.15.12. Can the MDMS GUI able to be configured to permit the operator to navigate an electrical connectivity hierarchy (e.g., substation by name/ID, transformer by name/ID, feeder by name/ID, meter by ID, etc.).

6.16. Describe your prior integrations with customer information systems (list the systems) through which a customer service representative (CSR) can execute an on-demand meter read or meter "ping" to verify connectivity/power.

7. Training

7.1. Identify standard training procedures for all PNM applicable personnel. Include course descriptions.

7.2. Identify any "train the trainer" courses for PNM personnel.

7.3. Identify the skills required by the system users to be able to fully utilize the system.

8. Project Management

8.1. Describe bidder's project management, thought leadership and utility guidance approach, including the support process from sale through post-implementation support. Identify key personnel and describe their experience in such roles.

8.2. Identify if key personnel are current employees of your company, contractors or yet to be determined.

9. Quality Program

9.1. Describe your company's quality program. How do you assess the quality of your system components?

9.2. Are your production facilities ISO 9001 2008 certified? If affirmative, please provide a copy of the certification.

9.3. Describe your company's customer service program.

9.4. Describe the options for licensing and support contracts.

10. Industry Experience

10.1. Describe Bidder's history and experience in conceptualizing, developing, testing, manufacturing, selling, delivering, installing, upgrading, improving, and supporting the delivery of an AMI system similar to what is being proposed to PNM.

10.1.1. Identify utility customers with similar projects and provide contact information for these references.

10.1.2. Provide examples of projects deployed by your company requiring interval meter data collection on a daily basis. Please provide the typical daily success read rate of such projects (i.e., collecting more than 99% of all interval data on a daily basis).

10.2. Please provide the number of installed metering points you company has operating utilizing:

10.2.1. 2-way mesh RF communications

10.2.2. Cellular communications

10.2.3. Performing time based functions such as time synchronization and Time of Use (TOU)

10.2.4. Providing daily load profile interval data in 5, 15-, 30, or 60-minute intervals.

10.2.5. How many have remote access control capability?

11. Other

11.1. Describe your company's approach to ensuring price certainty amid inflation uncertainty.

11.2. Is your company currently experiencing supply chain constraints?

11.2.1. Describe your company's approach to minimizing supply chain challenges.

11.2.2. What is the current timing between placing a meter order and customer delivery?

11.2.3. What steps can be taken to ensure that delivery aligns with the PNM timeline?

MV-90

MV-90: PNM has identified meters that rely upon being queried by MV-90 the SCOPE OF WORK, Table 2.

11.3. Does your proposed solution include all identified meter forms?

11.3.1. List the forms not being provided.

11.4. Does your proposed solution include identified existing MV-90 meter forms, eliminating the need for MV-90?

11.4.1. List the forms not supported.

11.5. Describe a successful migration from MV-90 to your proposed solution, including potential pitfalls or any customization that was needed.

11.5.1. Please provide a reference for the MV-90 migration for PNM

11.6. Does your proposed solution include the standard MV-90 reports?

11.6.1. Translation Summary Report?

11.6.2. Interval Pulse Data Report?

11.6.3. Interval Load Data Report?

11.6.4. kVA Analysis Report?

11.6.5. Peaks Report?

11.6.5.1. Non-coincident

11.6.6. Engineering Units, Compact

11.6.7. Engineering Units, Standard

11.6.7.1. Peaks Summary

11.6.7.2. Interval-by-interval

11.7. Report validation

11.7.1. By file

11.7.2. By time

11.8. Reports by time

11.8.1. Rolling

11.8.2. Clock

11.9. Does your proposed solution support aggregation, i.e.: the ability to combine interval load data from any number of metering points into summary files? All reports and graphics can be produced on summary files as well as pulse files.

11.10. Describe how MV-90 meter data is included in the proposed MDMS solution, particularly for VEE, data storage, data retrieval.

Load Research

Some load research is dependent upon data in MV-90, identified by [MV-90].

11.11. Identify the capability for providing additional reporting for at least one defined subset of meters to support load research. Please include information on the ability to configure the solution to change the defined subsets over time. [MV-90]

11.12. Does the Solution include the capability to provide additional reporting as described in 11.11 for at least 20 defined subsets of meters?

11.13. Does the Solution shall include the capability of automating the reporting described in 11.11 to run on a daily, weekly, monthly, or annual basis?

11.14. Does the proposed solution include the additional reporting described in 11.11 exceptions reports? Exceptions reports are defined for this purpose as reports that show which meters within the subset(s) have provided full data, or any data, to the Solution for a configurable number of days. For example, a report showing which meters within the load research subset(s) have not provided any data to the Solution for 3 or more days. [MV-90]

11.15. Does the proposed solution include the capability of providing multiple exceptions reports for each subset as described in 11.11 and 11.14, the different exceptions reports being for different numbers of days? For example, reports showing which meters within the load research subset(s) have not provided full data to the Solution for 3 or more days, 7 or more days, and 14 or more days. [MV-90]

11.16. Does the proposed solution include the additional reporting described in 11.11 data quality reports? Data quality reports describe the type of data present in the system, what VEE was performed on it, etc. For example, a report for the past month on all the meters in the main load research subset, showing for each meter what percentage of 15-minute intervals were estimated, what percentage had no data, and what percentage had data provided in the typical way. [MV-90]

11.17. Does the proposed solution include the capability of exporting energy use on an ad-hoc basis? For example, a report exporting the energy use for each meter at the smallest interval recorded by the meter (e.g., 5-minute or hourly) for the period April 1, 2020, through March 31, 2021. [MV-90]

11.18. Does the proposed solution include the capability of exporting energy use at the hourly level, even for meters that record it at sub-hourly levels (e.g., 15-minute or 5-minute intervals)?

11.19. Is the proposed solution's energy use export (11.17) configurable to include fields including, but not limited to: Meter Number or Load Research ID or Premise ID (any 1 of those 3 would be sufficient), datetime stamp, kWh, data quality field? (The data quality field would show which intervals were estimated, which were actual, etc.) [MV-90]

11.20. Is the proposed solution's energy use export (11.17) configurable to include fields including, but not limited to customer ID, premise ID, address?

11.21. Does the proposed solution have the additional reporting described in 11.11, 11.14, 11.15, 11.16, 11.17, and 11.18 configurable to cover different timeframes? The timeframes shall include, but not be limited to hours, days, weeks, months, and years. [MV-90]

11.22. Is the proposed solution capable of aggregating multiple meters or channels for load research purposes? For example, if a customer has one meter that measures its load, and another that measures its distributed generation, the solution would be capable of providing a "virtual meter" that nets out the load and the distributed generation.

11.23. Does the proposed solution capable of tracking which meters and channels measure load with positive numbers and which (if any) measure generation with positive numbers? For example, a table containing this data which could be reported on and exported would fulfill this requirement.

Meter Data Disaggregation

11.24. PNM is aware of a growing capability to process granular load data to provide customers with information on their appliance usage, disaggregating load as viewed from the meter to provide customers with more information about their energy data. Please describe your system's ability to support this functionality.

11.24.1. Describe any data disaggregation capabilities that your meter or MDMS can provide.

11.24.2. Can disaggregation capabilities interface with the customer HAN directly?

11.24.3. Describe any applications on the meter that could be developed to support such capabilities in the future.

11.24.4. Describe any software capabilities and/or optional modules /applications that would be able to disaggregate the meter data retrieved through the NAN/FAN.

11.24.4.1. How is disaggregation data captured in the MDMS? Is the disaggregation displayed on the MDMS GUI?

11.24.4.2. Would this disaggregated data be integrated within the customer energy portal?

11.24.5. Describe how meter data disaggregation techniques could be used to provide insight into the performance of behind-the-meter generation without directly monitoring the generation. Could this technique be used as a substitute to reliably monitor delivered and received energy (kWh)? Could this technique be used as a substitute to reliably monitor delivered and received reactive power (kVAR)?

Customer Energy Portal (for informational purposes)

11.25. What support for integrating/supporting a customer energy portal functionality is built into the MDMS?

11.25.1. Does your company partner with a 3rd party vendor to provide energy portal functionality or is that portal part of your own service offering?

11.25.2. What customer energy portal 3rd party vendor solutions have been integrated with the MDMS?

11.25.3. What standards or protocols have been utilized for communicating between the MDMS and customer energy portal?

11.25.4. Is it recommended that the customer energy portal communicate directly with the MDMS or though anther system (integration bus, data warehouse/lake, etc.)?

11.25.5. Have you supported integration with GreenButton Connect My Data and Download My Data? If so, describe that integration.

11.26. How can the energy portal website and/or mobile application become part of a broader interface (website and/or mobile application) for customers where the energy portal is just one aspect of the information that customers can access? (e.g., billing and payment, outage information and notifications, customer service requests, move-in/move-out/transfer, etc.)

11.27. Describe or illustrate how the customer energy portal provides graphical representation of consumption and generation interval kWh data (usage and generation).

11.28. Describe or illustrate how the customer energy portal provides graphical representation of net load interval kWh data made up from delivered and received interval channels.

11.29. Describe or illustrate how the customer energy portal supports graphical representation of demand data (kW) presentment for all customers, including demand-billed customers.

11.30. Describe how the customer energy portal provides customers with the capability to compare usage data to their historical usage (e.g., previous month, previous year) and/or the usage of their peers.

11.31. Describe or illustrate how the customer energy portal supports customers billed with multiple meters.

11.32. Describe or illustrate how the customer energy portal enables customers billed with multiple meters to view the usage data from multiple meters on the same graph and screen.

11.33. Describe or illustrate the different customer energy portal views that a customer could utilize to inspect usage data.

11.34. Describe or illustrate the process for customers configuring customer energy portal alerts for different thresholds.

11.35. Describe or illustrate the customer energy portal systems integration architecture with PNM internal systems and other AMI systems.

11.36. Does the customer energy portal support GreenButton DownloadMyData and GreenButton ConnectMyData functionality?

11.37. Describe whether and how the customer energy portal functionality provides a PNM employee/agent the capability to view screens as a customer to help with customer inquiries.

11.38. Are there built in provisions for protecting customer personal identifiable information (PII) and usage information in line with the Department of Energy DataGuard?

ATTACHMENT 6 - PROPOSAL FORMAT

Proposal Format

This section describes the format bidders are to use in responding to the RFP. Bidders should provide a response to all questions, even if the answer is "Does Not Apply" or "Does Not Comply." The bidder's proposal shall be in the format described below with each of the four sections clearly labeled and in the same order as detailed below.

Section 1.0 - Executive Summary

The Executive Summary should contain a brief description of the following items.

- The scope of the Bidder's proposed solution including all options requested for hosting of Meter Data Management System
- Recommended business relationship with PNM. Provide information on any sub-contractors included in your proposal such as meter installation, etc.
- Technology Overview
- Description of corporate qualifications, including industry experience, organizational structure, and a statement regarding financial soundness.

Section 2.0 – Technical Proposal

Please describe the technical aspects of your product and/or service offering. Bidders should pay particular attention to describing clearly and concisely the functional and performance benefits of their offering. The Technical Proposal should include a response to Attachment 5 – Technical Questionnaire with a response to each question/requirement. If the question is not applicable to the solution being proposed, please indicate so in the response with an explanation as to why it is not applicable.

Section 3.0 – Price and Business Relationship Proposal

Please provide pricing information. The pricing must include at least the following information, but may also contain any other pricing for solutions not covered below:

a. Meter pricing on a per meter basis given the quantities in the SCOPE OF WORK and forms and any other factors that could be used to reduce the per meter cost for:

   i. The vendor's RF Mesh Communication Solution using the Wi-SUN (IEEE 802.15.4g) communication protocol. If the solution is not capable of compliance with Wi-SUN communications protocol at the projected time of deployment, the vendor may propose their standard RF Mesh communication protocol along with a description of how the solution can be migrated to the Wi-SUN communication protocol in the future, without any need for hardware upgrades (i.e. over the air software/firmware upgrade). The data protocol shall be based on open Internet Protocol version 6 (IPv6) utilized throughout the architecture's stack. If IPv6 is not used throughout the architecture's stack, describe where within the architecture other protocols are used and if these protocols are proprietary or open.

   ii. The vendor's cellular communication solution with equipment pricing referenced to either Verizon Wireless or AT&T Wireless carriers for any meters that, given the Geographical Information (GIS) System Information, would be most economically served in the proposal using cellular communications. The pricing shall be for cellular communication utilizing 4G LTE where possible. The use of CDMA and/or GSM is acceptable only where 4G LTE coverage is not available.

b. Estimated quantities, description, and pricing for the telecommunication equipment needed to deploy the Neighborhood Area Network (NAN) Radio Frequency (RF) mesh network AMI system in PNM service territory. This includes but is not limited to routers, gateways, repeaters, collectors, etc.

i. The vendors RF Mesh solution based on the Wi-SUN communication protocol. If the solution is not capable of compliance with Wi-SUN communications protocol at the projected time of deployment, the vendor may propose their standard RF Mesh communication protocol along with a description of how the solution can be migrated to the Wi-SUN communication protocol in the future without any need for hardware upgrades (i.e. over the air software upgrade). The data protocol shall be open Internet Protocol version 6 (IPv6) solutions. This solution must utilize open standard protocols throughout the architecture's stack. If IPv6 is not used throughout the architecture's stack describe where within the architecture other protocols are used and if these protocols are proprietary or open.

c. Any recommended changes to meter configuration/form (e.g. change out of A base meters) and the cost to provide those changes.

d. Costs for a Meter Data Management system (MDMS) for each of the following:

   i. MDMS owned and operated in PNM data center;

   ii. MDMS hardware and software owned by PNM, but operated at vendor's data center;

   iii. MDMS provided as a hosted solution by the vendor.

e. Costs of any AMI head end systems for data collection utilized at PNM Data Center including hardware and software costs. Provide any costs associated with integration to each MDMS scenario listed.

   i. Head end system cost for mesh network meters

   ii. Head end system cost for LTE meters

f. Any additional pricing information not listed above needed to accurately analyze the proposed solution in terms of a fully functional, two-way AMI electric metering system.

This pricing should include all costs of all Hardware, Software, Services, Maintenance programs, and Licensing.

Section 4.0 – Appendices
Include relevant material needed to aid in the understanding of the proposal content. This can include additional detail which will enhance your response to a specific question in Part B as well as additional information which you believe will aid PNM's evaluation of proposals but was not specifically solicited. This may also include T&Cs, warranty etc.

Solution Provider (Vendor) Cloud Requirements and Standards

The PNMR Solution Provider (Vendor) is ultimately accountable for supporting the PNMR Business Owner with compliance to these controls listed below, and PNMR BTS Cloud Governance is available to assist in any way feasible. The Requirements and Standards below, outlines the accountability and controls which shall be in operation. Compliance with the following Requirements and Standards may be reviewed during Cloud Governance annual audit, or prior to, as needed.

FIRST READ | GENERAL NOTES*:*

1) ***Who should fill this in?*** This questionnaire should be completed by a representative of the solution provider [e.g., vendor/supplier] Cybersecurity team. The answers below will be used to help finalize data protection and cybersecurity contract language.
2) ***Clarification for Question #2***: We are NOT asking for general purpose hosting company "attestations of compliance" UNLESS, the target application/solution is specifically listed or cited as being covered by that "attestation of compliance". We are looking for "attestations of compliance" which are targeted at the proposed application/solution. For example, do not send a generic AWS, Google, or Azure attestation of compliance which has no reference whatsoever to the proposed application/solution.

INSTRUCTIONS:

1. **Enter:** Vendor Name: **Enter Here**
2. **Enter:** Cloud Service Name: **Enter Here**
3. **Enter:** Vendor contact information for the area/person responsible for Information Security controls and implementation: **Enter Here**
4. **Select**: In the below tables, for each blue "Select One", enter the most appropriate answer.
5. **Send:** All evidence or proof documents should be labeled with Vendor Name and Cloud Service Name in the subject line. Follow the instructions provided by PNMR business or Sourcing Department. **If no self-evident return instructions, as a last resort, send materials to the BTS Enterprise Architecture Team via** BTSEnterpriseArchitectureGroup@pnmresources.com.

Requirement/Standard	**Enter Here / Enter Here** **Vendor** Error! Reference source not found.**Response:**	**Additional** Error! Reference source not found.**Comment(s)** **Enter Here / Enter Here** Please use this area for additional comments:
1. Shall disclose and send PNMR examples (or a bulleted summary) of the PNMR related data types/fields which will be handled, exchanged, stored, and/or processed by the Service Provider (vendor). Please use specific examples of any sensitive or confidential information types.	**Can the vendor comply?** Select One If **yes**, please **provide/attach evidence document(s).** If **no**, please provide reason on the Comments field to the right:	

Requirement/Standard	**Enter Here / Enter Here** **Vendor** Error! Reference source not found.**Response:**	**Additional** Error! Reference source not found.**Comment(s)** **Enter Here / Enter Here** Please use this area for additional comments:
2. Shall supply Attestation of Compliance Report(s) or Certificate(s) of Evidence or Proof for any and all of the following (to the right). **NOTE**: We are NOT asking for general purpose hosting company “attestations of compliance” UNLESS, the target application/solution is specifically listed or cited as being covered by that “attestation of compliance”. We are looking for “attestations of compliance” which are targeted at the proposed application/solution. For example, do not send a generic AWS, Google, or Azure attestation of compliance which has no reference whatsoever to the proposed application/solution.	**Please check all that apply and provide/attach corresponding evidence document(s).** ☐ PCI DSS <**mandatory only for credit card use**> ☐ SOC II Type 2 Audit Attestation Report ☐ ISO/IEC 27001 Assessment Report or certification ☐ NIST 800-53 Assessment Report ☐ ISO/IEC 27017 Assessment Report ☐ ISO/IEC 27018 Assessment Report ☐ FedRAMP Report	
3. Shall complete the Third Party Vendor Assessment Questionnaire (imbedded to the right)	**Can the vendor comply?** Select One PNMR Third Party Vendor Assessment.	
4. Shall comply with implementation of AES 256 Encryption of Data-at-Rest on **storage** for all PNMR related data which is hosted or stored by the Service Provider (vendor).	**Can the vendor comply?** Select One If **yes**, please **provide/attach evidence document(s).** If **no**, please provide reason on the Comments field to the right:	
5. Shall comply with implementation of AES 256 Encryption of **databases** for all PNMR related data managed by Service Provider (vendor).	**Can the vendor comply?** Select One If **yes**, please **provide/attach evidence document(s).** If **no**, please provide reason on the Comments field to the right:	

Requirement/Standard	Enter Here / Enter Here Vendor Error! Reference source not found.Response:	Additional Error! Reference source not found.Comment(s) Enter Here / Enter Here Please use this area for additional comments:
6. Shall comply with implementing encryption of PNMR-related data in flight over the network and must use current TLS encryption standard or at minimum, most current TLS encryption standard which is not deprecated.	**Can the vendor comply?** Select One If **yes**, please **provide/attach evidence document(s).** If **no**, please provide reason on the Comments field to the right:	
7. Shall comply with implementation of Single Sign-on using SAML 2.0 to engage PNMR issued credentials for login access to target third-party solution/application. • Preferred: MS Azure Active Directory identity-as-a-service using ADFS 2.0 using SAML 2.0. • Accepted: OpenID or other Auth identity provider: using OAuth 2.0.)	**Can the vendor comply?** Select One **If no Single Sign-on using SAML 2.0 is available, then the following is required -> The Service Provider (vendor) will provide authentication credentials which support MFA (Multifactor Authentication) and implement the same for PNMR** Select One	
8. Shall disclose whether PNM data is segmented from other customer data, and if so, provide details of the segmentation architecture (Dedicated Tenant, Dedicated Server, etc.)	**Select One:** Select One If **PNMR data is segmented, provide/attach evidence document(s).** If **not**, provide reason(s) on the Comments field to the right:	
9. Shall provide evidence documents in support of the Service Provider's (vendor) Information Security Program – as described to the right:	**Please check all that apply and provide/attach corresponding evidence document(s).** ☐ Information Security ☐ Data Handling and Classification ☐ Incident Management and Response ☐ Data Commissioning/Destruction ☐ Human Resources Management ☐ Access/Entitlement Management ☐ Backup and Data Retention ☐ Change Management ☐ Physical Security ☐ Hardcopy Material Management ☐ IT Security/Cybersecurity ☐ Network Diagram ☐ Privacy Policy	

Requirement/Standard	Enter Here / Enter Here **Vendor** Error! Reference source not found.**Response:**	**Additional** Error! Reference source not found.**Comment(s)** **Enter Here / Enter Here** Please use this area for additional comments:
10. Shall disclose any and all industry standard framework(s) (if any) in which the Service Provider's (vendor) Information Security Program is based upon.	**Please check all that apply and provide/attach corresponding evidence document(s).** ☐ NIST 800-53 ☐ NIST Cybersecurity Framework (CSF) ☐ ISO 27001 If **none**, please provide reason on the Comments field to the right:	
11. Shall supply reference or proposed architecture and/or data flow diagrams which include **all data integrations** and/or information interface descriptions between the Service Provider (vendor) and PNMR.	**Can the vendor comply?** Select One **Please provide/attach evidence document(s).** If this cannot be provided, please provide reason on the Comments field to the right:	
12. Shall supply Service Level Agreement (SLA) metrics (for availability and recoverability) and all SLA measurements for this particular PNMR subscription service.	**Can the vendor comply?** Select One **Please provide/attach evidence document(s).** If this cannot be provided, please provide reason on the Comments field to the right:	
13. Shall disclose results of any recent Penetration Test or Vulnerability Test results.	**Can the vendor comply?** Select One **Please provide/attach evidence document(s).** If this cannot be provided, please provide reason on the Comments field to the right:	
14. Shall disclose any type of cybersecurity breaches which occurred within the last 12 months.	**Can the vendor comply?** Select One **Please provide/attach evidence document(s).** If this cannot be provided, please provide reason on the Comments field to the right:	
15. Shall disclose if any development or processing takes place in Nation State Cyber Threat Countries (China, Russia, North Korea, Iran).	Click or tap here to enter text.	

Requirement/Standard	**Enter Here / Enter Here Vendor** Error! Reference source not found.**Response:**	**Additional** Error! Reference source not found.**Comment(s) Enter Here / Enter Here** Please use this area for additional comments:
16. Shall disclose length of time for which the vendor has been established within business.	Click or tap here to enter text.	
17. Shall disclose number of FTE employees working at the business	Click or tap here to enter text.	
18. Shall disclose number of “active” clients using the same services being offered to PNMR	Click or tap here to enter text.	
19. Shall disclose whether background checks are performed for employees and contractors.	**Select One:** Select One	

Embedded Device Firmware Memory Sizing

Assumptions:

Firmware in embedded devices, such as smart meters, is stored in non-volatile flash memory that is also used for storage of persistent data. Separate software is typically not used in embedded devices, but if present, different memory sizing rules apply. If a current version of the firmware exists, then the size of the firmware can be obtained from the vendor. If the manufacturer does not yet have a version of the firmware written, then an additional memory allowance should be used. The rule of 9 assumes that new firmware versions will be downloaded in the field and the new firmware will be loaded by the existing firmware; however, if instead new firmware versions will be burned into flash memory (in offline mode), then less memory is required. Some utilities load new firmware offline and then replace/swap the meters in the field rather than download firmware to installed meters.

Calculation of Firmware Memory Sizing for Embedded Devices

The current firmware program size is defined as a parameter, designed as **x** or 1**x** in these calculations. In order to allow for future capability enhancements, as well as the need to store persistent data, including additional new persistent data, two times the current firmware size, or 2**x** memory, is required. Thus 1**x** + 2**x** = 3**x** is the assumed maximum size for future firmware versions.

During a firmware update, additional memory is required to store the new firmware in download format, as well as memory to store executable versions of both the new and old firmware. During the firmware upgrade, the new firmware version must be completely extracted and loaded into a different block of memory than the current firmware uses. The new firmware version is verified prior to transferring control to it, and a pointer redirects execution from the start of the old firmware executable to the start of the new firmware executable.

Thus, memory for 3 firmware versions, or 3**x** memory, is required during firmware upgrades for the following 3 firmware versions:

1) The current running firmware version
2) The stored version of the new firmware (in download format as loaded over the communications system). The downloaded image could be stored in main memory until it is burned to flash, but the image will be lost if there is a power cycle.
3) The new loaded firmware version, which must be verified prior to transferring control to it.

Rule of 9 Memory Size

Since the assumed maximum size for new firmware versions with additional features is 3**x** of the original firmware size and 3**x** memory is required during a firmware upgrade, 3**x** * 3**x** memory is needed **=** 9**x.** Thus 9 times the original firmware size is the recommended size for the non-volatile memory in embedded devices.

If new firmware will be loaded in off-line mode and meters swapped in the field, then 3**x** memory is needed.

For firmware updates of installed meters, and 1) if there is sufficient main (volatile) memory to store the new firmware version, and 2) power failures are not considered (e.g. the download will have to be restarted during a power failure), then 6**x** memory is needed.

PNM Exhibit JCH-3

On File with NMPRC

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

SELF AFFIRMATION

JONATHAN HAWKINS, Associate Director of Innovation and Communications for Public Service Company of New Mexico, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing **Direct Testimony of Jonathan Hawkins** and it is true and accurate based on my own personal knowledge and belief.

DATED this 3rd day of October, 2022.

_/s/Jonathan Hawkins___________
JONATHAN HAWKINS

GCG # 529844

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

DIRECT TESTIMONY

OF

ERIC C. MORGAN

October 3, 2022

NMPRC CASE NO. 22-00058-UT
INDEX TO THE DIRECT TESTIMONY OF
ERIC C. MORGAN

WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY
OF ERIC C. MORGAN
NMPRC CASE NO. 22-00058-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Eric C. Morgan. I am the Manager for Meter Reading and Collection for Public Service Company of New Mexico ("PNM" or "Company"). My address is 414 Silver Avenue, SW, Albuquerque, New Mexico 87102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS

A. My educational background and professional experience is summarized in PNM Exhibit ECM-1.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER FOR METER READING AND COLLECTION.

A. In my role, I have oversight for PNM's meter reading, credit collections, and regional payment centers. I have managed PNM's meter reading and credit collections operations since April 2010. I am also PNM's team lead for meter deployment and workforce re-deployment regarding the advanced metering infrastructure ("AMI") project.

Q. PLEASE STATE THE PURPOSE OF YOUR DIRECT TESTIMONY

A. The purpose of my testimony is to discuss and support: 1) PNM's plan for AMI meter deployment; 2) PNM's workforce re-deployment plan for meter readers; 3) the estimated savings PNM will achieve by reducing its meter reading operations when AMI meters are deployed; and 4) the costs associated with opting out of installation of an AMI meter.

II. AMI METER DEPLOYMENT

Q. WHAT STEPS MUST BE UNDERTAKEN TO DEPLOY AMI?

A. The AMI system involves an integrated and coordinated deployment of meter and field communications, as well as software applications. This technology must be integrated with PNM's existing customer and grid operational systems. The related deployment of the AMI head end system and meter data management system ("MDMS") software, as well as the integration of these technologies, are discussed in PNM witness Jonathan Hawkins's testimony. Given this context, the details on AMI meter deployment are provided below.

Q. PLEASE DESCRIBE THE OVERALL PLAN FOR METER DEPLOYMENT.

A. PNM will deploy AMI meters to all residential and small and medium commercial customers, except those that expressly opt-out. Generally speaking, PNM intends to deploy AMI meters along meter reading routes using PNM's billing cycles.[1] Moreover, as described in the testimony of PNM witness Laura Sanchez, PNM intends to prioritize meter deployments along meter routes with higher concentrations of low-income customers based on GIS mapping data. Ms. Sanchez describes the policy reasons behind why PNM is undertaking this prioritization.

Q. HOW DOES PNM INTEND TO STAGE ITS AMI DEPLOYMENT SCHEDULE?

A. The AMI system integration and AMI meter deployment will take a total of three-and-a-half years to complete.[2] Specifically, after Commission approval, PNM will spend six months designing and planning for systems installation, network and system integration, and AMI meter deployment. After that initial 6-month period, PNM will deploy and implement the AMI system, including the advanced meters, during the following three-and-a-half-year period. PNM will deploy its telecommunications network and implement and integrate the meter head end and MDMS during the first portion of the deployment period. Once these systems and telecommunications can communicate with the advanced meters, meter deployment will begin.

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[1] Generally speaking, a billing cycle includes a large group of customers and there are several meter-reading routes within each PNM billing cycle.

[2] *See* Guide for PNM's Grid Modernization at Fig. 6, prepared by EnerNex, attached as PNM Exhibit LES-2 to the Direct Testimony of PNM witness Laura E. Sanchez ("Guide").

PNM will finalize the specific AMI meter and field communications deployment plan after selecting the meter installation contractor and accounting for warehousing considerations. PNM will issue a request for proposal ("RFP") for a meter deployment contractor in the fourth quarter of 2022. The goal is to complete AMI deployment in year 4 after Commission approval of PNM's grid modernization application.

Q. WILL ALL CUSTOMER CLASSES RECEIVE AN AMI METER?

A. Not right away. PNM will deploy AMI meters to all residential, and small and medium commercial customers that do not expressly opt-out. PNM is continuing to evaluate the deployment of AMI meters to its largest customer classes and to certain customers who are billed using a manual process apart from PNM's Customer Information System ("CIS") billing system. It is PNM's intent to eventually have all its customers on an AMI meter.

Q. WHAT FUNCTIONALITY WILL BE INCLUDED IN THE AMI METER THAT WOULD AFFECT METER-READING PERSONNEL?

A. PNM will upgrade its business processes to use the AMI meters' remote connect and disconnect functionality. The remote connect and disconnect capability should be operational once PNM finishes the AMI system integration activities, including MDMS deployment. Once this capability is available, PNM will not need to physically send meter personnel to a home or business to connect or disconnect service.

Q. PLEASE DISCUSS PNM'S ESTIMATED COSTS FOR METER DEPLOYMENT.

A. As noted above, PNM will issue a meter deployment RFP in the fourth quarter of 2022. Until the RFP results are finalized, the cost estimate for PNM's AMI system deployment is based on the cost that Texas-New Mexico Power recently incurred for an upgrade to its AMI meters. Using this data from Texas-New Mexico Power, PNM estimates the cost of meter installation to be approximately $43.1 million, not including the cost of the AMI meters. The estimated cost of the AMI meters is discussed by PNM witness Hawkins.

PNM Table ECM-1 below shows PNM's estimated capital clearings for AMI meter installation over the six-year Implementation Plan period.[3]

PNM Table ECM-1

Capital Clearings for Advanced Metering	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
AMI Meter Installation Labor (external)	-	8,399,899	17,410,914	15,755,072	-	-
AMI Meter Installation Labor (internal)	-	311,346	645,343	583,968	-	-
Total	**-**	**8,711,245**	**18,056,257**	**16,339,040**	**-**	**-**

Note: Clearings are loaded with AFUDC, Project Management PMO Labor, Stores & Purchasing Loads (if applicable) and Labor Loads (if applicable). Additionally, clearings include an 8% contingency

Grand Total **43,106,542**

[3] PNM's Implementation Plan is attached to the Direct Testimony of PNM witness Laura Sanchez as PNM Exhibit LES-3.

III. ESTIMATED SAVINGS IN METER READING OPERATIONS

Q. PLEASE PROVIDE AN OVERVIEW OF PNM'S CURRENT METER-READING OPERATIONS.

A. Currently, PNM first obtains daily meter reading schedules from PNM's CIS billing system based on the billing cycle. Certain controls for meter readers exist prior to bill generation to ensure accuracy. Specifically, readers are alerted if the meter read indicates usage is two or three times greater than the usage the prior month and/or the same month a year ago. If an alert is triggered, the meter reader must re-enter the reading after verifying the meter number they are reading.

Upon completion of the daily reads, the completed and non-completed read information is uploaded and transferred back to the CIS billing system from the meter reading field collection system. The data, if necessary, is validated and approved by the revenue operations personnel for exception checks. Exception checks include high or low consumption, zero usage, negative usage, and tampering. If an exception check is not cleared by revenue operations, a meter reading reverify order is generated requiring the meter reader to revisit the premises to reverify the reading.

If a meter reading is skipped, for example because the meter could not be accessed, PNM estimates the energy usage for the account and notes the estimated read in the

CIS billing system. The customer is notified for the reason for an estimation. Estimated reads are based on prior usage for the customer of record. By Commission rule, PNM cannot estimate a customer bill for more than two consecutive months.[4] If a customer does not agree with the estimated usage, a reverify order for meter reading can be requested. This will require the meter reader to visit the customer's premises to read the meter.

Q. PLEASE DESCRIBE HOW PNM READS EXISTING METERS.

A. PNM currently deploys a variety of meters in its service territory. Most of PNM's current meters require a meter reader to physically conduct a monthly read at the customer's premises to accurately record customer usage. PNM currently has three methods for manually reading meters. The traditional method is that a PNM employee manually reads the registers on a meter to determine the amount of usage. A majority of PNM's meters are read this way. PNM also has a walk-by method that requires the meter reader to be within a certain range for the meter to communicate with a hand-held device. This method for reading meters transmits via radio frequency ("RF"). PNM currently has 44,533 meters that collect customer consumption via a RF walk-by. Finally, a meter reader may have to plug into a meter using a probe to retrieve multiple registers of meter data. PNM has 17,151 meters requiring data to be collected via probe. The data collected from these

[4] NMAC 17.5.410.15 (C)

methods are aggregated on hand-held meter reading devices and transferred from the Meter Reading Field Collection System to the CIS billing system.

Q. ARE METER READING COSTS INCLUDED IN CURRENT CUSTOMER RATES?

A. Yes.

Q. PLEASE PROVIDE AN ESTIMATE OF THE PROJECTED SAVINGS FOR REDUCED METER READING OPERATIONS AS A RESULT OF THE DEPLOYMENT OF AMI METERS.

A. PNM expects to avoid certain costs after full AMI deployment is completed. The avoided costs after AMI system integration and deployment fall into the following categories: meter readers, meter reader coordinators, meter reader supervisors and vehicle costs. PNM has estimated approximately $18.6 million in savings associated with these costs over years 3 through 6 of PNM's Implementation Plan. This estimate is based on 91 employees and 80 vehicles.

PNM Table ECM-2 below provides PNM's estimated savings from AMI meter deployment during the implementation plan period.

PNM Table ECM-2

O&M Expenses for Advanced Metering	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Avoided Meter Reader Coordinator costs	-	-	(149,752)	(306,992)	(472,094)	(495,699)
Avoided meter reader costs	-	-	(1,139,241)	(2,335,443)	(3,591,456)	(4,910,269)
Avoided Meter Reader Supervisor costs	-	-	(74,876)	(228,372)	(448,309)	(470,724)
Avoided meter reader vehicle costs	-	-	(400,000)	(800,000)	(1,200,000)	(1,600,000)

IV. REDEPLOYMENT OF METER READERS

Q. PLEASE DESCRIBE PNM'S PROPOSAL FOR METER READER REDEPLOYMENT.

A. PNM is committed to full redeployment of its meter reading staff and does not intend to lay-off or let go any meter readers. PNM currently employs 80 full-time meter readers. PNM's current annual meter reader attrition rate is 43 percent, meaning that approximately 43 percent of its full-time meter readers leave that position of their own accord on an annual basis. As AMI meter installation is completed on meter reading routes, meter readers will no longer be reading meters manually and will start transitioning to new roles within PNM if they opt to remain with the Company. Meter readers will be redeployed until the final AMI meter is installed. If there are staffing shortages through attrition, work will be supplemented with subcontractors and/or temporary employees.

Q. ARE NEW POSITIONS GOING TO BE CREATED AS A RESULT OF THE GRID MODERNIZATION PROJECTS AND WILL METER READERS HAVE AN OPPORTUNITY TO FILL THOSE POSITIONS?

A. Yes, new positions will be created as a result of the grid modernization projects and meter reader employees will have an opportunity to fill those positions. For example, PNM meter reader employees could be redeployed for opt-out reads, AMI pick up reads, troubleshooting communications, system administrators, as well as for data analytics staffing. PNM plans to offer specific re-training opportunities for its meter readers that would ensure they can qualify for these opportunities.

PNM estimates $4 million in expense over years one through five for meter reader retraining and process change management. Additional expenses for an AMI Pick Up Read employee, an AMI troubleshooting employee, and opt-out meter reading employees and vehicles in this plan total $1.3 million over the six-year plan.

PNM Table ECM-3 below provides PNM's estimated O&M expenses for AMI-related operations and maintenance expenses over the implementation plan period.

PNM Table ECM-3

O&M Expenses for Advanced Metering	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
AMI Business Process Change Management	400,000	400,000	400,000	400,000	400,000	-
AMI Meter Reader Retraining	400,000	400,000	400,000	400,000	400,000	-
AMI Vehicle Costs	-	-	-	-	-	100,000
AMI Pick Up Reads Employee	-	-	-	-	107,358	112,189
AMI Pick Up Reads Employee Annual Employee Expenses (Flat)	-	-	-	-	-	3,250
AMI Meter Troubleshooting Employee	-	107,358	112,189	117,237	122,513	128,026
AMI Meter Troubleshooting Employee Annual Employee Expenses (Flat)	-	3,250	3,250	3,250	3,250	3,250
Opt-Out Meter Reading Employees	-	-	-	-	-	322,073
Opt-Out Meter Reading Employees Annual Employee Expenses (Flat)	-	-	-	-	-	9,750
Total	**800,000**	**910,608**	**(848,430)**	**(2,750,320)**	**(4,678,738)**	**(6,798,155)**

Q. WHAT EXISTING POSITIONS CAN METER READERS APPLY TO FILL AT PNM?

A. Employees who choose not to transition to new roles created by grid modernization will also have opportunities for apprenticeships as journeyman lineman, meter journeyman, or line locators. PNM currently offers 4-year apprenticeship programs for journeyman lineman or meter journeyman.

V. OPT-OUT FEES FOR AMI METERS

Q. PLEASE SUMMARIZE PNM'S PROPOSAL TO ALLOW CUSTOMERS TO OPT-OUT FROM HAVING AN AMI METER.

A. PNM proposes to allow customers to opt-out of AMI deployment, if they choose. However, in the event a customer chooses to opt-out of the new meters, PNM will incur costs to continue manually reading the old meters on a monthly basis. PNM also will incur one-time costs for meter exchanges if: (1) a customer does not notify PNM that they opt-out of an AMI meter until after the AMI meter is installed; or (2) a customer notifies PNM that they opt-out before an AMI meter is installed. To avoid shifting these costs to customers with AMI, PNM proposes to establish: (1) a monthly opt-out fee based on the estimated cost of service to manually read meters for opt-out customers; (2) a one-time opt-out fee for customers that did not notify PNM that they wished to opt-out prior to an AMI meter installation; and (3) a one-time opt-out fee for customers that notify PNM of the opt-out decision prior to an AMI meter installation. PNM estimated the opt-out fees for this Application but intends to update the associated fees closer to the completion of AMI meter deployment and based on the actual number of customers opting out and the documented cost components for each fee.

Q. WHAT COSTS ARE INCLUDED IN THE MONTHLY OPT-OUT FEE AND WHAT IS THE FEE?

A. PNM has included estimates of the costs of labor, vehicle mileage, and vehicle lease and maintenance costs in the monthly opt-out fee. Attached to this testimony is PNM Exhibit ECM-2, which is a workpaper that estimates the costs PNM will incur and will ultimately charge customers on a monthly basis for opting out. PNM currently estimates the monthly opt-out fee to be $28.31.

Q. PLEASE EXPLAIN THE BASIC ASSUMPTIONS USED TO CALCULATE THE ESTIMATED MONTHLY OPT-OUT FEE AS SHOWN IN PNM EXHIBIT ECM-2.

A. To estimate the monthly opt-out fee, PNM assumed that 0.3 percent of total metered customers will opt-out of AMI meters. This assumption is based on information provided by PNM's consultant, EnerNex. EnerNex analyzed the opt-out rate for 28 utilities that have AMI and determined the mean and median opt out fees to be 0.4% and 0.3%, respectively. Based on EnerNex's analysis and recommendation, PNM selected 0.3% as the assumed opt out rate for the purpose of projecting the opt-out cost.

The opt-out fee calculation assumes PNM meter readers will take 25 minutes per manual read, given how large PNM's service territory is, which equates to 2.4 meter reads per hour per meter reader. Based on this assumption, a single meter reader could conduct about 19 meter reads per day. Based on these assumptions, PNM will need to maintain three meters readers and three vehicles to conduct monthly meter reads for opt-out customers.

Q. WHEN WILL PNM BEGIN CHARGING THE MONTHLY OPT-OUT FEE?

A. PNM will not begin charging the monthly opt-out fee until full deployment of the AMI meters, the communications network, and the MDMS are all complete. Until communications are enabled for AMI and the MDMS can receive the data from the

AMI meters, PNM will still be required to manually read meters. As such, PNM does not intend to charge the monthly opt-out fee until the AMI system is deployed to defray the costs associated with manual meter reads.

Q. WHAT IS THE ONE-TIME FEE FOR CUSTOMERS THAT OPT-OUT PRIOR TO AMI METER INSTALLATION?

A. PNM proposes a one-time opt-out fee of $18.60 if the customer opts-out prior to installation of the AMI meter. This fee is based on changes to the CIS billing system necessary to track and charge the opt-out fee, the cost of manual meter reading hand-held devices, administration of the opt-out program and various communications to the customers. Please see PNM Exhibit ECM-2 for the detailed information regarding this cost-based fee.

Q. WHAT IS THE ONE-TIME FEE FOR CUSTOMERS THAT HAVE AN AMI METER INSTALLED AND THEN INFORM PNM OF THE DECISION TO OPT-OUT?

A. PNM proposes a one-time opt-out fee of $49.17 if the customer opts-out after installation of the AMI meter. This fee is based on costs identified above for the opt-out fee prior to AMI meter installation, as well as the labor and vehicle costs associated with the meter swap. Please see PNM Exhibit ECM-2 for the detailed information regarding this cost-based fee.

Q. WHEN WILL PNM CHARGE THE ONE-TIME OPT-OUT FEE TO CUSTOMERS?

A. PNM will charge the one-time opt-out fee to customers as they make the decision to opt-out of an AMI meter, with the fee based on whether the customer opts-out *prior to* or *after* AMI meter installation.

Q. ARE THE OPT-OUT FEES REFLECTED IN PNM EXHIBIT ECM-2 THE ACTUAL OPT-OUT FEES THAT WILL BE CHARGED TO CUSTOMERS?

A. No. As explained by PNM witness Stella Chan, PNM has provided an estimate of the rates for customers who opt-out. When PNM has more updated data closer to AMI implementation, it will file an advice notice with the Commission to formally propose one-time opt-out fees. Subsequently, after AMI meter installation nears completion, PNM will file an advice notice for the monthly opt-out fee. At that time, PNM will have more updated information, particularly as to the total number of customers who opt-out. With that information, PNM will have a better understanding of the total ongoing costs it will incur to continue manual meter reads. For example, if significantly more customers opt-out of AMI meters than PNM has estimated in PNM Exhibit ECM-2, PNM may require additional vehicles, equipment, and personnel to accomplish the manual meter reads.

Q. HOW WILL CUSTOMERS COMMUNICATE TO PNM THAT THEY WISH TO OPT-OUT OF AN AMI METER?

A. PNM will create an opt-out form that customers can complete and submit on PNM's website. In the alternative, customers will be able to call customer service to opt-out through a self-affirmation. I have attached a proposed format for the opt-out form as PNM Exhibit ECM-3. The information in PNM Exhibit ECM-3 will be used to create an online form on PNM's website and a script for customer calls to PNM's Customer Service department requesting to opt-out.

Q. WHAT INFORMATION WILL CUSTOMERS PROVIDE IN SUBMITTING THE OPT-OUT FORM?

A. The form will request the customer's name, account number, service address, current contact phone number, and email address. The form also asks customers if they understand and consent that they are opting out of an AMI meter and that the customer will be charged a one-time opt-out fee and an ongoing monthly charge. For customers who seek to opt-out via telephone with a customer service representative, the customer service representative will seek the same information and disclosures.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

GCG#529870

ERIC C. MORGAN

414 Silver Ave SW Albuquerque, NM 87114 · (505) 246-5818
eric.morgan@pnm.com

Experienced manager seeking next step in leadership at PNM Electric Services where my leadership experience, effective communication skills, safety focus, dedication to quality service, and customer focus will contribute toward the growth of PNM's Transmission and Distribution Operations.

EXPERIENCE

APRIL 2010 TO PRESENT

METER READING AND COLLECTIONS MANAGER

PNM ELECTRIC SERVICES, ALBUQUERQUE, NM

- Develop and implement Operational goals and objectives; assist with marketing programs and initiatives to support customers
- Maintains staff by providing guidance and direction on recruiting, selecting, orienting, and training employees
- Accomplishes staff results by communicating job expectations, planning monitoring, and appraising job results
- Responsible for development and managing multi-million dollar O&M budget
- Establishes strategic goals by gathering pertinent business, financial, service, and operations information
- Implement, support, and monitor loss control and safety policies to ensure employee awareness and a safe work environment
- Maintain credibility and provide leadership to the community through involvement in civic and social organizations and interaction with city, state, and tribal government officials
- Maintain quality service by enforcing quality and customers focus standards, analyzing and resolving quality and customer service problems, recommending system improvements.
- Manage union and non-union labor relations issues within area of responsibility
- Oversee scheduling and training for meter readers, field collectors, and regional payment centers

FEBRUARY 2010 – APRIL 2010

TEMPORARY CONTACT CENTER MANAGER

PNM ELECTRIC SERVICES, ALBUQUERQUE, NM

- Develop objectives for the Call Center's day to day activities
- Conduct effective resource planning and maximize productivity of resources
- Collect and analyze call center statistics
- Responsible for development and managing multi-million dollar O&M budget
- Hire, coach and provide training personnel to maintain high customer service standards
- Evaluate performance with key metrics
- Prepare and communicate reports for various departments within the customer service operations

ARPIL 2006 – FEBRUARY 2010

CONTACT CENTER SUPERVISOR

PNM ELECTRIC SERVICES, ALBUQUERQUE, NM

- Provide information and assistance on personnel actions including hiring, counseling, training, performance planning and appraisals
- Handle difficult customer inquiries and problems for PNM and Texas New Mexico Power customers
- Assist with complex/political customer complaints and develop resolutions that will meet the customer's needs and protect the financial position of the company
- Communicate job activities with personnel, and other team members to ensure everyone stays informed of job duties
- Assist and develop CCR's to perform in compliance with Call Center procedures, company policies, and work standards
- Working knowledge of all customer service functions, including service transactions, call center operations, cash handling, emergency calls, meter handling, billing, collections, and customer interactions

Education

1988-1990

ATHLETIC SCHOLARSHIP – UNIVERSITY OF NEW MEXICO

1987-1988

ATHLETIC SCHOLARSHIP – CAL STATE UNIVERSITY OF LONG BEACH

1984-1986

HIGH SCHOOL DIPLOMA – LONG BEACH POLYTECHNIC HIGH SCHOOL

SKILLS

- Highly self-motivated with a positive attitude
- Reliable and consistent
- Strong leadership abilities; fair, empathetic, problem solver
- PNM Negotiations committee member 2012, 2015, & 2022
- Team player, team builder, team motivator
- Excellent coaching skills
- Exceptional communication skills
- Proficient in MS Office

ACTIVITIES & INTERESTS

- Fitness
- Hiking
- Travel
- Golf
- Bike Riding

PNM Exhibit ECM-2
Opt-Out Calculation

		Total Meters	Opt-Out Rate	
1	**Total Opt-Out Meters**	581,000	0.3000%	**1,743**

		A	B	C	D	E
	Ongoing Costs					
				A x B	*C x Line 1 x 12*	*D / Line 1 / 12*
		Unit rate ($/unit)	Units	Cost per Meter ($/meter)	Annual Cost ($)	Monthly Cost per Meter ($/meter)
2	Manual read trip labor cost (hours)	$ 51.28	0.4167	$ 21.37	$ 446,975	$ 21.37
3	Manual read vehicle mileage cost (miles)	$ 0.38	8.6	$ 3.27	$ 68,395	$ 3.27
				A x B	*C x 12*	*D / Line 1 /12*
		Lease Cost ($/vehicle-month)	Vehicles	Total Monthly Lease Cost ($)	Annual Cost ($)	Monthly Lease Cost per Meter ($/Meter)
4	Manual read vehicle monthly lease costs	$ 964	3	$ 2,892	$ 34,704	$ 1.66
5	Vehicle maintenance	$ 1,167	3	$ 3,500	$ 42,000	$ 2.01
6	**Ongoing Monthly AMI meter opt out fee**				*Line 2 + Line 3 + Line 4 + Line 5*	**$ 28.31**

		A	B	C	D
	One-Time Costs				
		Unit Cost ($/unit)	Units	Total Cost ($)	One-Time Cost per Meter ($/meter)
				A x B	*C / Line 1*
6	Printing and mailing opt-out confirmation postcards	$ 6,000	1	$ 6,000	$ 3.44
7	Implement changes in CIS to track and charge opt-out fees - Total Meters	$ 137,000	1	$ 137,000	$ 0.24
8	Additional handhelds	$ 5,000	3	$ 15,000	$ 8.61
9	Opt-Out first year administration	$ 11,000	1	$ 11,000	$ 6.31
9	**One-time Fee for Opt-Out prior to meter exchange**			*Line 6 + Line 7 + Line 8 + Line 9*	**$ 18.60**
	Additional One-Time costs for opt-opt after meter exchange if meter must be exchanged				
10	Meter exchange trip labor	$ 51.28	0.5000	$ 25.64	$ 25.64
11	Vehicle monthly costs			*Line 4 E*	$ 1.66
12	Vehicle mileage costs			*Line 3 E*	$ 3.27
13	**Subtotal meter exchange**				**$ 30.57**
14	**One-time Fee for Opt-Out after meter exchange with meter exchange, or if disable comm**			*Line 9 + Line 13*	**$ 49.17**

GCG#529868

Proposed Format for

Opt-Out Consent Form

PNM will require customers who intend to opt out of Advanced Metering Infrastructure ("AMI") to affirm their decision to opt out via an Opt-Out Consent Form. PNM customers will be able to opt out electronically on PNM's website or by calling customer service to provide consent through a self-affirmation.

This document, which represents the proposed format for an Opt-Out Consent Form, lists the fields that customers will have to fill out on the online form. Similarly, this document is representative of the script that customer service representatives will read to customers who choose to opt out over the telephone.

***Note that the Opt-Out Fees listed below are preliminary. PNM will file an advice notice for the one-time Opt-Out Fee prior to advanced meter deployment. PNM will file a second advice notice for the monthly Opt-Out Fee after advanced meter deployment is complete.*

The required fields included in the Opt-Out Consent Form (available electronically or over the telephone with a customer service representative) are:

- Customer Name
- Customer Account Number
- Service Address of Customer
- Phone Number of Customer
- Email of Customer
- Closed Question Selection (yes/no)
    - Does the customer consent to and understand that they are opting out of having an advanced meter with built-in communications ability installed at their premise (house or business)?
    - Does the customer understand that by opting out, the customer will be charged a one-time Opt-Out Fee?
        - The Opt-Out Fee for a customer that notifies PNM of the decision to opt out prior to the AMI meter installation is $18.60.
        - The Opt-Out Fee for a customer that notifies PNM of the decision to opt out after the initial AMI meter installation is $49.17.
        - Public Service Company of New Mexico understands that you (have/have not) had an advanced meter with built-in communications ability installed at your premise (house or business), and therefore, your charge will be $TBD.
    - Does the customer understand that by opting out, the customer will be charged a monthly Opt-Out Fee of $28.31?
        - The monthly Opt-Out Fee is meant to cover the costs of meter reading, as well as the labor and other expenses that Public Service Company of New Mexico must incur to continue reading your meter.
- Signature (may be electronic)
    - Printed Customer Name
    - Signature Consent of Customer (electronic signature permitted)

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

SELF AFFIRMATION

ERIC MORGAN, Manager, Meter Reading and Collection Department for Public Service Company of New Mexico, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing **Direct Testimony of Eric Morgan** and it is true snd accurate based on my own personal knowledge and blief.

DATED this 3rd day of October, 2022

/s/ Eric Morgan
ERIC MORGAN

GCG#529847

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	))))))))	**Case No. 22-00058-UT**

DIRECT TESTIMONY

OF

KYLE T. SANDERS

October 3, 2022

NMPRC CASE NO. 22-00058-UT
INDEX TO THE DIRECT TESTIMONY OF
KYLE T. SANDERS

WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY
OF KYLE T. SANDERS
NMPRC CASE NO. 22-00058-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Kyle T. Sanders. I am the Director of Cost of Service and Corporate Budget for PNM Resources, Inc. ("PNMR"). My address is 414 Silver Avenue, SW, Albuquerque, New Mexico 87102.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. My educational background and professional experience are summarized in PNM Exhibit KTS-1, which includes a list of cases in which I have testified, including those before the New Mexico Public Regulation Commission ("Commission" or "NMPRC").

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF COST OF SERVICE AND CORPORATE BUDGET.

A. I am responsible for revenue requirement and cost of service-related work for the public utility subsidiaries of PNMR, including Public Service Company of New Mexico ("PNM"). This responsibility includes preparation of revenue requirement analysis and testimony for regulatory filings. I am also responsible for PNMR's corporate budget activities, which include preparation of PNM's Annual Operating Plan.

Q. PLEASE STATE THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. My Direct Testimony will focus on the following areas:

- I present PNM's annual revenue requirements associated with the implementation of certain grid modernization projects requested in this filing, which PNM proposes to recover through a Grid Modernization Rider ("GMR").
- I discuss PNM's requests for approval to create three regulatory assets or liabilities related to legacy meters, startup costs, and over- and under-collection of costs.
- I describe the proposed GMR, including the revenue requirement components that PNM intends to include in the GMR, and the timeline of the annual review and reconciliation filing associated with the GMR.
- I describe the proposed GMR annual review and reconciliation filings, and the true-up process included in the GMR annual filing.

Q. APART FROM YOUR STATEMENT OF QUALIFICATIONS, ARE YOU SPONSORING ANY ADDITIONAL EXHIBITS?

A. Yes, as follows:

- PNM Exhibit KTS-2 – Total Estimated Grid Modernization Revenue Requirement. This exhibit details the estimated revenue requirement associated with all grid modernization projects for years 1 through 6 consolidated into a summary exhibit.

- PNM Exhibit KTS-3 – Estimated Grid Modernization Revenue Requirement by Project. This exhibit details the estimated revenue requirement broken down by each grid modernization project for years 1 through 6 and serves as a workpaper to support the total revenue requirement presented in PNM Exhibit KTS-2.
- PNM Exhibit KTS-4 – Total Grid Modernization Year 1 Revenue Requirement. This exhibit details the estimated revenue requirement associated with all grid modernization projects for year 1 broken out by month.
- PNM Exhibit KTS-5 – Grid Modernization Year 1 Revenue Requirement by Project. This exhibit details the estimated year 1 revenue requirement broken down by each grid modernization project by month.

II. GMR REVENUE REQUIREMENT

Q. HAS PNM CALCULATED A GMR REVENUE REQUIREMENT FOR ITS ANTICIPATED GMR COSTS?

A. Yes. Please see PNM Exhibit KTS-2 for a detailed revenue requirement calculation of all grid modernization projects for years 1 through 6. Additionally, PNM Exhibit KTS-3 provides a revenue requirement for each grid modernization project. The revenue requirements for each of the projects by year are presented below in PNM Table KTS-1.

PNM Table KTS-1
Grid Modernization Revenue Requirements by Project
($ in thousands)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
ADMS	$ 824	$ 335	$ 838	$ 1,782	$ 3,181	$ 5,022
Advanced Metering	5,744	9,533	18,586	24,198	22,755	17,928
Customer Information & Analytics	-	1,466	1,501	1,509	1,521	1,534
Cybersecurity	9	469	969	961	977	967
Data Management & Architecture	1,216	2,571	2,870	3,275	3,372	3,412
Distribution Planning & Engineering	384	624	817	1,815	2,184	2,097
Distribution Automation	37	2,260	4,769	6,717	8,761	10,855
Telecommunications	391	497	2,779	3,882	4,962	5,990
Program Oversight	1,189	1,241	1,296	1,354	1,414	1,476
Total Revenue Requirement	**$ 9,794**	**$ 18,996**	**$ 34,424**	**$ 45,493**	**$ 49,127**	**$ 49,281**

Q. WHAT COST COMPONENTS IS PNM PROPOSING BE INCLUDED IN THE GMR ANNUAL REVENUE REQUIREMENT?

A. PNM's proposed GMR will recover capital costs, operating expense such as operations and maintenance ("O&M") net of O&M savings, and taxes associated with the grid modernization projects identified in the Grid Modernization Implementation Plan ("Plan").[1] Based on these amounts, the revenue requirement will include the following components:

- Rate Base – includes estimated gross plant in service and associated accumulated depreciation and Accumulated Deferred Income Tax ("ADIT") balances.
- Return on Rate Base – includes a debt and equity return on estimated rate base.

[1] PNM's Grid Modernization Implementation Plan (the "Plan") details all of the grid modernization projects for which PNM seeks approval of in its Application. The Plan is attached to the Direct Testimony of PNM witness Laura Sanchez as PNM Exhibit LES-3.

- Operating Expenses – includes estimated O&M expenses, depreciation expense and estimated property taxes based on the previous year net book value of the assets.
- Income and Other Taxes – federal and state income tax calculations for the return on rate base and revenue tax based on the current New Mexico Supervision and Inspection rates.

Q. WHAT CAPITAL COSTS ARE INCLUDED IN THE REVENUE REQUIREMENTS IN PNM TABLE KTS-1?

A. PNM has included the capital clearings for the following nine separate projects requested, including: Advanced Distribution Management System ("ADMS"), Advanced Metering, Customer Information & Analytics, Cybersecurity, Data Management and Architecture, Distribution Planning and Engineering, Distribution Automation, Telecommunications and Program Oversight. These projects are outlined in the Plan for this Application. Additional details of the capital investment amounts are discussed in more detail in the Direct Testimonies of PNM witnesses Warner, Hawkins, Morgan, Sanchez, Cervantes and Rowey. Please see below PNM Table KTS-2 for capital costs by project, by year, along with the PNM witness that provides support for the capital costs.

PNM Table KTS-2
Grid Modernization Capital Clearings by Project
($ in thousands)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Witness
ADMS	$ -	$ -	$ -	$ 7,572	$ -	$ 15,400	PNM Witness Omni Warner
Advanced Metering							
Meter Installation Costs	-	8,711	18,056	16,339	-	-	PNM Witness Eric Morgan
Meter and Meter Infrastructure Costs	1,685	39,583	45,400	39,469	1,723	-	PNM Witness Jon Hawkins
Total Advanced Metering	1,685	48,295	63,456	55,808	1,723	-	
Customer Information & Analytics	-	522	-	-	-	-	PNM Witness Mario Cervantes
Cybersecurity	69	4,062	211	210	217	-	PNM Witness Jon Hawkins
Data Management & Architecture	2,865	1,579	1,091	1,090	-	-	PNM Witness Jon Hawkins
Distribution Automation							
Dist. Automation Communications Equipment	4,153	4,217	-	-	-	-	PNM Witness Jon Hawkins
Switches and Devices	-	11,968	16,151	16,620	17,661	17,930	PNM Witness Omni Warner
Total Distribution Automation	4,153	16,185	16,151	16,620	17,661	17,930	
Distribution Planning & Engineering	-	-	1,386	7,459	-	-	PNM Witness Omni Warner
Telecommunications	183	7,881	8,035	8,071	8,327	8,198	PNM Witness Jon Hawkins
Total Grid Modernization Capital Clearings	**$ 8,954**	**$ 78,524**	**$ 90,329**	**$ 96,832**	**$ 27,928**	**$ 41,528**	

Q. WHAT O&M COSTS ARE INCLUDED IN THE REVENUE REQUIREMENTS IN PNM TABLE KTS-1?

A. The O&M expenses included in the GMR revenue requirement are incremental costs associated with the grid modernization projects listed above and are not already reflected in PNM's base rates. These O&M amounts are net of O&M savings that are achieved. O&M savings reflects costs that will no longer be incurred as meter reading needs diminish. Please refer to PNM witness Eric Morgan for further discussion. Please see below PNM Table KTS-3 for O&M expense by project, by year, along with the PNM witness that provides support for the expenses.

PNM Table KTS-3
Grid Modernization O&M Expense by Project
($ in thousands)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Witness
ADMS	$ 819	$ 333	$ 833	$ 858	$ 1,885	$ 1,962	PNM Witness Omni Warner
Advanced Metering							
Meter Readers Costs and Savings	800	911	(848)	(2,750)	(4,679)	(6,798)	PNM Witness Eric Morgan
Meter and Software Costs	3,739	3,831	4,068	4,357	4,325	4,380	PNM Witness Jon Hawkins
Call Center Support	-	496	518	540	563	-	PNM Witness Mario Cervantes
AMI Marketing	1,165	1,172	1,180	1,188	1,196	-	PNM Witness Julie Rowey
Total Advanced Metering	5,704	6,411	4,917	3,334	1,405	(2,418)	
Customer Information & Analytics	-	1,390	1,405	1,420	1,436	1,453	PNM Witness Mario Cervantes
Cybersecurity	-	217	228	240	252	264	PNM Witness Jon Hawkins
Data Management & Architecture	1,105	1,853	1,988	2,250	2,340	2,435	PNM Witness Jon Hawkins
Distribution Automation	10	618	742	893	1,083	1,325	PNM Witness Omni Warner
Distribution Planning & Engineering	382	621	645	671	697	724	PNM Witness Omni Warner
Program Oversight	1,183	1,235	1,290	1,347	1,407	1,469	PNM Witness Laura Sanchez
Telecommunications	383	400	765	799	834	871	PNM Witness Jon Hawkins
Total Grid Modernization O&M	**$ 9,587**	**$ 13,079**	**$ 12,813**	**$ 11,812**	**$ 11,338**	**$ 8,085**	

Q. HOW IS THE REVENUE REQUIREMENT MODEL FUNCTIONALIZED TO FACILITATE THE PROPER ALLOCATION OF GRID MODERNIZATION PROJECTS?

A. The revenue requirement model is functionalized into six separate categories to allow for proper allocation of costs to different customer classes. PNM witness Stella Chan discusses the allocation of costs through rate design in her Direct Testimony. Some categories in the revenue requirement model are not utilized in this filing but serve as placeholders in the model in the event that future GMR filings have costs that would be booked to these categories. The categories are as follows:

- Production: This category is not utilized in this filing.
- Distribution – Meters: This category includes costs for the advanced metering infrastructure ("AMI") meters.
- Distribution – Other: This category includes all other distribution plant and expenses other than the AMI meters.
- Transmission: This category is not utilized in this filing.
- General and Intangible ("G&I") – Software: This category includes costs associated with software. This includes both hosted software and cloud-based software.
- G&I – Other: This category includes all other general and intangible related costs other than software.
- Administrative and General ("A&G) expenses – this category includes the administrative level expenses such as project oversight that cannot be readily classified to the functional categories listed above.

Q. WHAT DEPRECIATION RATES ARE UTILIZED IN THE REVENUE REQUIREMENT MODEL?

A. PNM utilized composite depreciation rates for the Distribution – Other and the G&I – Other categories based on Commission approved depreciation rates from NMPRC Case No. 16-00276-UT. As actual projects are completed and classified to the proper FERC plant account, PNM would use the Commission-approved depreciation rate for the respective plant accounts to determine actual depreciation expense. The depreciation rate for the AMI meters is 5% and is based on the expected useful life of the meters of 20 years as discussed by PNM witness Jon Hawkins. The depreciation rate for G&I – Software is 10%. This is based on the 10-year contract duration of the AMI software.

Q. HOW WILL THE REVENUES FROM OPT-OUT CUSTOMERS BE HANDLED?

A. Revenues from the opt-out customers will be used to reduce the GMR revenue requirement. The revenue credit for the opt-out fees is included in PNM Exhibit KTS-3 WP Advanced Metering as a reduction to the revenue requirement for this project. The expenses associated with opt-out customers will also be included in the GMR and are discussed in more detail by PNM witness Eric Morgan.

Q. WHAT COST OF CAPITAL IS PNM PROPOSING TO UTILIZE TO CALCULATE THE RETURN COMPONENT OF THE REVENUE REQUIREMENT?

A. PNM proposes to use its actual year-end weighed average cost of capital (“WACC”) to calculate the return on rate base component. The year-end WACC is also utilized by PNM in its annual Earnings Test Filings and the RPS Rider filings with the Commission. The 2021 year-end WACC is 6.34%. The table below provides the components of the WACC. The filing for each rate year will utilize the most recent actual year-end WACC available. For example, the year 2 GMR filing on March 1, 2024 will utilize the 2023 year-end WACC for the plan year of September 1, 2024 through August 31, 2025. This is consistent with the methodology used in PNM's RPS Rider filings.

PNM Table KTS-4
Summary of Total Capitalization and the Weighted Average Cost of Capital
December 31, 2021 Year End Weighted Average Cost of Capital

Line No.	Capital Component	Total Capitalization Test Period	Percentage of Total Capitalization	Capital Component Cost	Weighted Average Cost
1	Long Term Debt	$ 1,815,845	47.95%	2.85%	1.37%
2	Preferred Stock	$ 11,529	0.30%	4.62%	0.01%
3	Common Equity	$ 1,959,858	51.75%	9.575%	4.95%
4	Total	3,787,233	100.00%		6.34%
				Tax Rate	25.40%
					Tax gross up
				Debt	1.37%
				Preferred	0.02%
				Common	6.64%
				Total	8.03%

Q. IS PNM REQUESTING APPROVAL FOR A SPECIFIC YEAR'S REVENUE REQUIREMENT?

A. Yes. PNM is requesting approval of the year 1 revenue requirement for recovery under the GMR during the period of September 1, 2023 through August 31, 2024.

Q. WHAT IS THE REVENUE REQUIREMENT OF YEAR 1 THAT PNM IS PROPOSING TO RECOVER UNDER THE GMR?

A. The first-year revenue requirement under the GMR is estimated to be $9.8M. Please see PNM Exhibit KTS-4 for a detailed revenue requirement calculation of all grid modernization projects for year 1 provided by month. Additionally, PNM Exhibit KTS-5 provides the monthly revenue requirement by each grid modernization project. The detailed components of the revenue requirement by project are summarized below in PNM Table KTS-5. Please refer to the testimony of PNM witness Stella Chan for discussion of the Grid Modernization Rider Rate.

PNM Table KTS-5
Grid Modernization First Year Revenue Requirement

	ADMS	Advanced Metering	Customer Information & Analytics	Cybersecurity	Data Management &	Distribution Planning & Engineering	Distribution Automation	Telecom.	Program Oversight	Total
Return on Rate Base	$ -	$ 8,814	$ -	$ 3,086	$ 44,288	$ -	$ 21,724	$ 2,854	$ -	$ 80,765
O&M	819,333	5,704,238	-	-	1,105,229	382,007	9,750	383,371	1,182,863	9,586,791
Depreciation Expense	-	-	-	4,620	47,747	-	-	1,790	-	54,157
Taxes Other Than Income	4,167	29,067	-	554	6,152	1,943	190	1,977	6,016	50,066
Revenue Credit for Opt-Out	-	-	-	-	-	-	-	-	-	-
Federal Income Tax	-	1,837	-	689	9,709	-	4,528	613	-	17,376
State Income Tax	-	516	-	194	2,728	-	1,272	172	-	4,882
Total Revenue Requirement	**$ 823,500**	**$ 5,744,472**	**$ -**	**$ 9,143**	**$ 1,215,852**	**$ 383,950**	**$ 37,463**	**$ 390,778**	**$ 1,188,878**	**$ 9,794,037**

III. REGULATORY ASSETS

Q. IS PNM REQUESTING ANY REGULATORY ASSETS OR LIABILITIES IN THIS CASE?

A. Yes. PNM is requesting the authority to create two regulatory assets and one regulatory asset or liability. One regulatory asset is for the undepreciated investment in the legacy meters that PNM is proposing to replace with AMI meters in this case. Second, PNM is requesting authority to create a regulatory asset for grid modernization startup costs incurred before the GMR will go into effect on September 1, 2023. And third, PNM is requesting the authority to create a regulatory asset or liability to record the any over or under collection of costs through the GMR.

Q. PLEASE EXPLAIN HOW PNM PROPOSES TO RECOVER ITS REMAINING INVESTMENT IN LEGACY METERS?

A. PNM proposes to create a regulatory asset for legacy meters that are retired and replaced with AMI meters. Recovery of the costs associated with this regulatory asset will be addressed in a future rate case. PNM would propose to recover the regulatory asset for legacy meters through base rates and not the GMR.

Q. IS PNM PROPOSING AN AMORTIZATION PERIOD FOR THE REGULATORY ASSET FOR LEGACY METERS IN THIS CASE?

A. No. PNM is proposing that the amortization period for the legacy meter regulatory asset be addressed in a subsequent rate case.

Q. WILL THE LEGACY METERS CONTINUE TO DEPRECIATE AFTER THEY HAVE BEEN MOVED INTO THE REGULATORY ASSET AT RETIREMENT?

A. For the specific purpose of this regulatory asset, PNM is proposing that until the legacy meters are addressed in PNM's next base rate case, PNM will continue to amortize this requested regulatory asset at a rate equal to the currently approved depreciation rate. Currently, legacy meters are depreciating at a rate of 4.72% consistent with the depreciation rates utilized in NMPRC Case No. 16-00276-UT. The continued amortization of legacy meter costs in a regulatory asset means that PNM will be seeking recovery in a rate case of an amount that reflects the remaining net book value of the meters as if they had remained in service and continued depreciation. While this proposal in this context is not typical for undepreciated capital costs placed in a regulatory asset, PNM supports this approach for legacy meters given the unique circumstances of early retirement of meters and the recovery of the costs of the replacement meters via a mechanism separate from base rates.

Q. PLEASE DESCRIBE THE REGULATORY ASSET BEING REQUESTED FOR GRID MODERNIZATION COSTS INCURRED AFTER THE GRID MODERNIZATION PLAN IS APPROVED BUT BEFORE THE IMPLEMENTATION OF THE GMR.

A. PNM has requested approval of the Application by July 1, 2023, with implementation of the GMR by September 1, 2023.[2] PNM is seeking approval to recover grid modernization costs incurred between the approval of the Application and implementation of the GMR. Allowing PNM to begin spending the program budget as soon as the Plan is approved allows customers to begin to benefit from the programs in this request sooner. This regulatory asset will be recovered through the GMR and included in the next annual review and reconciliation filing, currently expected to be March of 2024.[3]

Q. IS PNM PROPOSING AN AMORTIZATION PERIOD FOR THE REGULATORY ASSET FOR GMR START-UP COSTS?

A. No, not at this time. PNM will include the regulatory asset and requested amortization period in the year 2 GMR filing on March 1, 2024.

Q. WHAT COSTS WILL BE INCLUDED IN THE REGULATORY ASSET FOR STARTUP COSTS?

A. PNM expects to start work on the projects outlined in the Plan prior to the implementation of the GMR. This could include expenses associated with the

[2] As noted in the Direct Testimony of PNM witness Sanchez, should the Commission approve PNM's Application prior to July 1, 2023, PNM would prefer to implement the Rider prior to September 1, 2023, taking into consideration PNM's concerns with implementing the Rider during the summer peak season. PNM witness Stella Chan addresses implementation of the Rider during the summer months of June, July and August.

[3] The expected March 2024 filing is described in more detail below.

various projects, including expenditures needed to integrate new software to work with PNM's existing systems. Specifically, as described in the testimony of PNM witness Hawkins, timely implementation of the AMI meters requires that PNM purchase and start deploying software that will be used to test AMI meters before they are deployed in the field. A delay in purchasing and deploying this software could delay PNM's proposed AMI meter deployment schedule.

Q. PLEASE DESCRIBE THE REGULATORY ASSET OR LIABILITY BEING REQUESTED FOR ANY OVER OR UNDER COLLECTION OF COSTS COLLECTED THROUGH THE GMR.

A. PNM proposes to recover actual costs associated with the grid modernization projects, net of any savings, through the GMR. Given that the rates will be initially set based on estimates, PNM requests the authority to record any difference between the revenues collected in a given rate period and the actual costs incurred for the same period to a regulatory asset or liability. This is described in detail in section V of my testimony below.

IV. GRID MODERNIZATION RIDER

Q. PLEASE DESCRIBE THE RIDER PNM IS PROPOSING AND WHEN FUTURE FILINGS WILL BE MADE TO TRUE-UP THE GMR.

A. As discussed above, PNM proposes to implement the rider or GMR by September 1, 2023. PNM proposes to recover costs associated with the grid modernization projects through the GMR over the useful lives of the assets. The proposed GMR will use forecasted information to calculate a projected revenue requirement, which is then charged for the upcoming rate year, similar to the mechanics of PNM's Renewable Portfolio Standard ("RPS") Rider. The rate year for the GMR is expected to be September 1st through August 31st.

After this initial Application, PNM expects to file the projected revenue requirement and rates with the Commission on March 1st of each year to be effective September 1st of that same year. The annual filing will contain two components: updated forecasted costs for the following rate year based on the best available information and a true-up to actuals. Both of these components are discussed in more detail later in my testimony.

Please see below PNM Table KTS-6 for the proposed structure of the annual rate filings for plan years 1 through 6. For purposes of this testimony, "Year 1" through "Year 6" refer to the rate periods outlined in this table. PNM may revise the dates in the table below if a Commission final order comes sooner than July 1 or is extended beyond the anticipated date.

PNM Table KTS-6
Grid Modernization Rider Proposed Timeline for Filings and Updates

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Filing Date	October 3, 2022	March 1, 2024	March 1, 2025	March 1, 2026	March 1, 2027	March 1, 2028
Rate Effective Date	September 1, 2023	September 1, 2024	September 1, 2025	September 1, 2026	September 1, 2027	September 1, 2028
Rate Period	9/1/2023 - 8/31/2024	9/1/2024 - 8/31/2025	9/1/2025 - 8/31/2026	9/1/2026 - 8/31/2027	9/1/2027 - 8/31/2028	9/1/2028 - 8/31/2029
Actuals Trued-up*	N/A	N/A	9/1/2023 - 8/31/2024	9/1/2024 - 8/31/2025	9/1/2025 - 8/31/2026	9/1/2026 - 8/31/2027

*Includes true-ups to actuals through stated filing date with any over or under collections of actuals vs. estimates, and updated forecasts for projects for the upcoming rate period.

Q. DOES THIS FILING DIFFER FROM FUTURE ANNUAL GMR FILINGS?

A. Yes. Because this is the initial filing, this filing includes 6 years of forecasted revenue requirements. Future filings will include only a forecasted revenue requirement for the upcoming rate year and a true-up to actuals of the previous fully completed rate year. PNM will reconcile back to this initial filing to identify material changes in cost estimates. As the projects outlined in PNM's current Plan for years 1 through 6 are completed or are nearing completion, PNM expects to file for another comprehensive plan with additional projects or continuations of projects. It is expected that the next comprehensive filing for years 7 through 11 will occur in or around 2027, or the filing for year 5.

Q. WHY IS PNM PROPOSING A START DATE OF SEPTEMBER 1 FOR THE GMR?

A. PNM witness Chan explains why PNM proposes that the GMR take effect in September.

V. GMR ANNUAL REVIEW AND RECONCILIATION FILING, WITH A COMPONENT TRUE-UP PROCESS

Q. HOW WILL PNM ADJUST AND UPDATE THE GMR REVENUE REQUIREMENT IN ITS ANNUAL REVIEW AND RECONCILIATION FILING?

A. As noted above, the GMR will use forecasted costs, net of savings, to calculate the revenue requirement for September 1st through August 31st for the upcoming year. These forecasts will be based on the best available information for that upcoming year and may include updated bid information or new vendor estimates for planned projects. Additionally, PNM proposes to true-up the projected revenue requirement with actual costs and compare to actual revenue collected through the GMR. PNM will include the true-up in each subsequent annual March 1st filing. The comparison of projections to actuals will result in either an over collection or an under collection of the revenue requirement. The over collection or under collection will be included in the upcoming rate year estimated revenue requirement by either reducing (over collection) or increasing (under collection) the projected revenue requirement.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THIS WILL WORK?

A. Yes. I will use year 1 as an example. The year 1 rate period is expected to be September 1, 2023 through August 31, 2024. The year 1 rate period will not have concluded by the time the year 2 filing is expected to be made in March of 2024, so it will be trued-up in the year 3 rate filing on March 1, 2025. As such, there will not be a true-up included in the year 2 filing, and instead, the year 2 filing will only include an updated information for the next rate period based on the best available data for that forthcoming year. Please see below PNM Table KTS-7, which includes the filing date of the annual review and reconciliation proceeding and the rate period that will be trued-up in each annual filing.

PNM Table KTS-7
True-up to Actuals Timeline

Filing Date	Actuals Trued-Up
3/1/2024	N/A
3/1/2025	9/1/2023 - 8/31/2024
3/1/2026	9/1/2024 - 8/31/2025
3/1/2027	9/1/2025 - 8/31/2026
3/1/2028	9/1/2026 - 8/31/2027

Q. HOW WILL PNM TREAT AN OVER OR UNDER COLLECTION WHEN AMOUNTS HAVE BEEN TRUED-UP TO ACTUALS?

A. If there is an over collection of the actual revenue requirement, this amount will be used to reduce the revenue requirement for the next rate period. Similarly, if there is an under collection of the actual revenue requirement, this amount will increase the revenue requirement for the next rate period.

Q. IS PNM PROPOSING TO INCLUDE ANY INTEREST OR CARRYING CHARGES ON THE OVER OR UNDER COLLECTION AMOUNTS?

A. Yes. PNM is proposing a carrying charge of 4%. PNM will apply the carrying charge to both over and under collections in a symmetrical treatment.

Q. WHY IS IT REASONABLE TO USE 4% IN THE GMR FILINGS TO CALCULATE CARRYING CHARGES?

A. The 4% carrying charge is consistent with carrying charges that the Commission has approved for over/under collection of regulatory assets in other approved rider mechanisms. Given the short-term nature of an over/under collection of a regulatory asset, it is appropriate to use a carrying charge less that the full WACC of the utility.

VI. CONCLUSION

Q. PLEASE SUMMARIZE THE APPROVALS PNM IS REQUESTING WITH RESPECT TO REGULATORY ASSETS AND LIABILITIES IN THIS PROCEEDING?

A. PNM is requesting the following Commission approvals related to regulatory assets and liabilities: (1) to establish a regulatory asset for the undepreciated investment in the legacy meters; (2) to create a regulatory asset for grid modernization startup costs incurred after approval of the Plan but before the GMR goes into effect; (3)

to create a regulatory asset or liability to record the any over or under collection of costs through the GMR.

Q. WHAT ARE YOUR GENERAL CONCLUSIONS?

A. The Commission should approve the proposed form of the GMR to recover costs associated the grid modernization projects. The year 1 GMR revenue requirement reflects the first year of costs to implement PNM's Plan for grid modernization and should be approved.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CGG#589859

KYLE T. SANDERS
EDUCATIONAL AND PROFESSIONAL SUMMARY

Name: Kyle T. Sanders

Address: PNM Resources Inc.
MS 0915
414 Silver SW
Albuquerque, NM 87102

Position: Director of Corporate Budget and Cost of Service

Education: Bachelor of Accountancy, New Mexico State University, 2009

Employment: PNM Services Company:
Senior Revenue Requirements Analyst (2012-2013)
Financial Analyst (2013-2015)
Manager of Cost of Service (2015-2017)
Director Financial Planning and Load Forecasting (2017)
Director of Corporate Budget and Cost of Service (2019-current)
New Mexico Gas Company:
Director of Planning and Forecasting (2017-2019)

Testimony and Affidavit Filed:

Texas Public Utility Commission

- In the Matter of the Application of Texas-New Mexico Power Company for Interim Update of Wholesale Transmission Rates, PUCT Docket No. 44953, filed July 17, 2015
- In the Matter of the Application of Texas-New Mexico Power Company for Interim Update of Wholesale Transmission Rates, PUCT Docket No. 45559, filed January 29, 2016
- In the Matter of the Application of Texas-New Mexico Power Company for Interim Update of Wholesale Transmission Rates, PUCT Docket No. 46184, filed July 19, 2016
- In the Matter of the Application of Texas-New Mexico Power Company for Interim Update of Wholesale Transmission Rates, PUCT Docket No. 46786, filed January 20, 2017
- In the Matter of the Application of Texas-New Mexico Power Company for A Distribution Cost Recovery Factor, PUCT Docket No. 50731, filed April 6, 2020
- In the Matter of the Application of Texas-New Mexico Power Company for A Distribution Cost Recovery Factor, PUCT Docket No. 51959, filed April 6, 2021

New Mexico Public Regulation Commission

- 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, NMPRC Case No. 12-00007-UT, filed February 26, 2016 (PNM's Rider No. 36 Reconciliation for 2015.)
- In the Matter of PNM's Application for Approval of Its Renewable Energy Act Plan for 2017 and Proposed 2017 Rider Rate under Rate Rider No. 36, NMPRC Case No. 16-00148-UT, filed June 1, 2016
- 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, NMPRC Case No. 12-00007-UT, filed February 28, 2017 (PNM's Rider No. 36 Reconciliation for 2016.)
- In the Matter of PNM's Application for Approval of Its Renewable Energy Act Plan for 2018 and Proposed 2018 Rider Rate under Rate Rider No. 36, NMPRC Case No. 17-00129-UT, filed June 1, 2017
- In the Matter of PNM's Application for Approval of Two Purchased Power Agreements and an Energy Storage Agreement Pursuant to 17.9.551 NMAC, An Addendum to the Special Service Contract with Great Kudu LLC, and Amended Rider No. 49, NMPRC Case No. 21-00031-UT, filed February 8, 2021
- In the Matter of the Application of Public Service Company of New Mexico for Decertification and Abandonment of 114 MW of Leased Palo Verde Nuclear Generating Station Capacity and Sale and Transfer of Related Assets and for Approval to Procure New Resources under 17.9.551 NMAC, NMPRC Case No. 21-00083-UT, filed April 2, 2021
- In the Matter of Public Service Company of New Mexico's Request for Approval of New Resources under 17.9.551 NMAC to Replace 114 MW of Leased Palo Verde Nuclear Generating Station Capacity, NMPRC Case No. 21-00215-UT, filed August 27, 2021
- In the Matter of the Application of Public Service Company of New Mexico for Continued Use of Fuel and Purchased Power Cost Adjustment Clause, NMPRC Case No. 22-00166-UT, filed June 17, 2022.

Federal Energy Regulatory Commission

- Public Service Company of New Mexico Filing to Revise Depreciation Rates in PNM's Transmission Formula Rate, FERC Docket No. ER 16-2713-000, filed September 30, 2016
- Public Service Company of New Mexico Filing of Transmission Service Agreements with Leeward Renewable Energy Development, LLC, FERC Docket No. ER 21-1363-001, affidavit filed April 19, 2021

GCG#529855

PNM Exhibit KTS-2
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	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-2**									
2	**Total Estimated Grid Modernization Revenue Requirement**									
3	**All Projects**									
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	$ -	$ 33,035,902	$ 94,361,455	$ 150,169,589	$ 151,892,128	$ 151,892,128
21				Distribution Plant - Other	-	11,968,345	28,119,194	44,739,662	62,401,128	80,330,989
22			Total Distribution Plant		-	45,004,247	122,480,648	194,909,251	214,293,257	232,223,117
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	2,934,096	20,560,860	25,378,934	41,711,011	41,928,153	57,328,411
38				G&I Plant - Other	6,020,375	21,912,926	29,947,631	38,018,470	46,345,017	54,543,081
39			Total General & Intangible Plant		8,954,471	42,473,786	55,326,565	79,729,481	88,273,170	111,871,492
40										
41				**Total Gross Plant**	8,954,471	87,478,033	177,807,213	274,638,732	302,566,427	344,094,610
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	(509,927)	(3,694,861)	(9,808,137)	(17,359,680)	(24,954,286)
58				Distribution Plant - Other	-	(219,491)	(770,872)	(1,773,005)	(3,246,666)	(5,209,867)
59			Total Distribution Plant		-	(729,417)	(4,465,733)	(11,581,142)	(20,606,346)	(30,164,153)
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	(52,366)	(1,264,213)	(3,561,202)	(6,915,700)	(11,097,658)	(16,060,486)
75				G&I Plant - Other	(1,790)	(374,523)	(1,897,156)	(3,892,651)	(6,369,575)	(9,331,664)
76			Total General & Intangible Plant		(54,157)	(1,638,735)	(5,458,358)	(10,808,350)	(17,467,233)	(25,392,150)
77										
78				**Total Accumulated Depreciation**	(54,157)	(2,368,153)	(9,924,091)	(22,389,492)	(38,073,579)	(55,556,303)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	(820,844)	(3,377,395)	(7,538,637)	(11,468,251)	(14,191,384)
110				Total Distribution ADIT - Other	-	(248,025)	(559,675)	(1,045,646)	(1,696,674)	(2,496,462)
111			Total Distribution ADIT		-	(1,068,869)	(3,937,070)	(8,584,283)	(13,164,925)	(16,687,847)
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	(62,313)	(934,379)	(2,530,282)	(5,048,564)	(5,824,780)	(7,371,299)
142				Total G&I ADIT - Other	(57,593)	(428,230)	(1,237,069)	(2,108,243)	(3,012,560)	(3,920,607)
143			Total General & Intangible ADIT		(119,906)	(1,362,610)	(3,767,351)	(7,156,806)	(8,837,340)	(11,291,906)
144										
145				**Total ADIT**	(119,906)	(2,431,478)	(7,704,421)	(15,741,090)	(22,002,265)	(27,979,752)
146										
147		**Total Rate Base**			**$ 8,780,408**	**$ 82,678,402**	**$ 160,178,701**	**$ 236,508,151**	**$ 242,490,583**	**$ 260,558,554**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			80,765	2,609,587	10,151,565	14,989,058	15,368,203	16,513,288
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	2,464,580	3,129,966	1,483,291	(309,643)	(2,181,698)	(6,034,122)
158				Other	391,757	1,217,375	1,364,084	1,540,661	1,755,824	2,024,120
159			Total Distribution O&M		2,856,337	4,347,341	2,847,375	1,231,018	(425,874)	(4,010,001)
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	3,971,641	5,943,187	7,469,678	7,885,648	9,042,234	9,252,331
165				Other	1,575,950	1,553,138	1,206,106	1,348,217	1,315,303	1,373,614
166			Total General & Intagible O&M		5,547,591	7,496,324	8,675,784	9,233,865	10,357,537	10,625,946
167										
168			A&G		1,182,863	1,235,148	1,289,787	1,346,884	1,406,550	1,468,902
169										
170				**Total O&M**	9,586,791	13,078,814	12,812,945	11,811,767	11,338,213	8,084,846
171										

PNM Exhibit KTS-2
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	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-2**						
2	**Total Estimated Grid Modernization Revenue Requirement**						
3	**All Projects**						
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	509,927	3,184,934	6,113,276	7,551,543	7,594,606
187	Distribution Depreciation Expense - Other	-	219,491	551,382	1,002,133	1,473,662	1,963,200
188	Distribution Depreciation Expense Total	-	729,417	3,736,316	7,115,409	9,025,204	9,557,807
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	52,366	1,211,846	2,296,990	3,354,497	4,181,958	4,962,828
204	G&I Depreciation Expense - Other	1,790	372,732	1,522,634	1,995,495	2,476,924	2,962,089
205	Total General & Intagible Depreciation Expense	54,157	1,584,578	3,819,623	5,349,992	6,658,882	7,924,917
206							
207	**Total Depreciation Expense**	54,157	2,313,996	7,555,939	12,465,401	15,684,087	17,482,724
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	278	357,786	997,333	1,543,976	1,479,857
214	Other	-	87,768	129,237	300,832	472,633	650,699
215	Total Distribution Property Tax	-	88,046	487,023	1,298,164	2,016,609	2,130,556
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	508	42,403	212,263	239,995	382,748	339,135
221	Other	-	46,871	236,922	308,555	375,384	439,730
222	Total General & Intangible Property Tax	508	89,275	449,186	548,550	758,132	778,865
223							
224	**Total Property Taxes**	508	177,320	936,209	1,846,714	2,774,742	2,909,421
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	(17,443)	(563,586)	(2,192,409)	(3,237,151)	(3,319,034)	(3,566,335)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	2,043	87,302	285,069	470,292	591,726	659,585
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	2,043	87,302	285,069	470,292	591,726	659,585
235	Depreciation and AFUDC Debt	(472,072)	(9,100,678)	(20,759,617)	(31,640,427)	(24,650,298)	(23,533,414)
236	Deferred State Income Tax	26,300	507,026	1,156,579	1,762,781	1,373,341	1,311,116
237	Total Temporary Differences	(445,771)	(8,593,653)	(19,603,037)	(29,877,646)	(23,276,958)	(22,222,298)
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	93,612	1,804,667	4,116,638	6,274,306	4,888,161	4,666,683
240							
241	Net Taxable Equity Return	(286,793)	(4,655,683)	(7,242,175)	(11,381,142)	(5,747,902)	(3,949,078)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	(76,236)	(1,237,588)	(1,925,137)	(3,025,369)	(1,527,924)	(1,049,756)
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	93,612	1,804,667	4,116,638	6,274,306	4,888,161	4,666,683
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	17,376	567,080	2,191,501	3,248,936	3,360,237	3,616,927
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	(363,030)	(5,893,270)	(9,167,312)	(14,406,511)	(7,275,826)	(4,998,834)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	(21,419)	(347,703)	(540,871)	(849,984)	(429,274)	(294,931)
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	26,300	507,026	1,156,579	1,762,781	1,373,341	1,311,116
257	**Total State Income Tax**	4,882	159,323	615,708	912,797	944,067	1,016,184
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
261	**Total Revenue Credits**	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
262							
263	**Total Revenue Requirement Before Revenue Tax**	9,744,479	18,899,592	34,250,298	45,262,392	48,878,154	49,031,996
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	49,558	96,118	174,188	230,192	248,581	249,364
266							
267	**Total Revenue Requirement**	**$ 9,794,037**	**$ 18,995,710**	**$ 34,424,486**	**$ 45,492,585**	**$ 49,126,735**	**$ 49,281,359**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	80,765	2,609,587	10,151,565	14,989,058	15,368,203	16,513,288
271	O&M	9,586,791	13,078,814	12,812,945	11,811,767	11,338,213	8,084,846
272	Depreciation Expense	54,157	2,313,996	7,555,939	12,465,401	15,684,087	17,482,724
273	Taxes Other Than Income	50,066	273,439	1,110,397	2,076,907	3,023,323	3,158,785
274	Net Allowable Federal Income Tax	17,376	567,080	2,191,501	3,248,936	3,360,237	3,616,927
275	Net Allowable State Income Tax	4,882	159,323	615,708	912,797	944,067	1,016,184
276	Revenue Credits	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
277	**Total Revenue Requirement**	$ 9,794,037	$ 18,995,710	$ 34,424,486	$ 45,492,585	$ 49,126,735	$ 49,281,359
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-4.						

PNM Exhibit KTS-3
Estimated Grid Modernization Revenue Requirement By Project

Table of Contents

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP ADMS - Estimated Revenue Requirement ADMS Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	$ -	$ -	$ -	$ 7,572,492	$ 7,572,492	$ 22,972,750
38				G&I Plant - Other	-	-	-	-	-	-
39			Total General & Intangible Plant		-	-	-	7,572,492	7,572,492	22,972,750
40										
41				**Total Gross Plant**	-	-	-	7,572,492	7,572,492	22,972,750
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	-	-	(378,625)	(1,135,874)	(2,663,136)
75				G&I Plant - Other	-	-	-	-	-	-
76			Total General & Intangible Plant		-	-	-	(378,625)	(1,135,874)	(2,663,136)
77										
78				**Total Accumulated Depreciation**	-	-	-	(378,625)	(1,135,874)	(2,663,136)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	-	-	(579,852)	(1,031,739)	(2,662,878)
142				Total G&I ADIT - Other	-	-	-	-	-	-
143			Total General & Intangible ADIT		-	-	-	(579,852)	(1,031,739)	(2,662,878)
144										
145				**Total ADIT**	-	-	-	(579,852)	(1,031,739)	(2,662,878)
146										
147		**Total Rate Base**			**$ -**	**$ -**	**$ -**	**$ 6,614,015**	**$ 5,404,879**	**$ 17,646,736**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			-	-	-	419,173	342,542	1,118,388
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	819,333	333,333	833,333	858,333	1,884,583	1,962,146
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		819,333	333,333	833,333	858,333	1,884,583	1,962,146
167										
168			A&G							
169										
170				**Total O&M**	819,333	333,333	833,333	858,333	1,884,583	1,962,146
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP ADMS - Estimated Revenue Requirement ADMS Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	-	-	378,625	757,249	1,527,262
204	G&I Depreciation Expense - Other	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	378,625	757,249	1,527,262
206							
207	**Total Depreciation Expense**	-	-	-	378,625	757,249	1,527,262
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	-	-	-	79,133	70,803
221	Other	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	79,133	70,803
223							
224	**Total Property Taxes**	-	-	-	-	79,133	70,803
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	-	-	-	(90,528)	(73,978)	(241,536)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	-	-	-	14,285	28,569	57,620
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	14,285	28,569	57,620
235	Depreciation and AFUDC Debt	-	-	-	(2,282,882)	(1,779,083)	(6,421,805)
236	Deferred State Income Tax	-	-	-	127,186	99,118	357,778
237	Total Temporary Differences	-	-	-	(2,155,696)	(1,679,965)	(6,064,028)
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	-	-	-	452,696	352,793	1,273,446
240							
241	Net Taxable Equity Return	-	-	-	(1,360,070)	(1,030,039)	(3,856,109)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	(361,538)	(273,808)	(1,025,042)
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	452,696	352,793	1,273,446
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	-	-	-	91,158	78,985	248,403
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	-	-	-	(1,721,608)	(1,303,847)	(4,881,151)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	(101,575)	(76,927)	(287,988)
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	-	-	-	127,186	99,118	357,778
257	**Total State Income Tax**	-	-	-	25,611	22,191	69,790
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	819,333	333,333	833,333	1,772,901	3,164,683	4,996,792
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	4,167	1,695	4,238	9,017	16,095	25,412
266							
267	**Total Revenue Requirement**	**$ 823,500**	**$ 335,029**	**$ 837,571**	**$ 1,781,917**	**$ 3,180,778**	**$ 5,022,204**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	-	-	-	419,173	342,542	1,118,388
271	O&M	819,333	333,333	833,333	858,333	1,884,583	1,962,146
272	Depreciation Expense	-	-	-	378,625	757,249	1,527,262
273	Taxes Other Than Income	4,167	1,695	4,238	9,017	95,227	96,215
274	Net Allowable Federal Income Tax	-	-	-	91,158	78,985	248,403
275	Net Allowable State Income Tax	-	-	-	25,611	22,191	69,790
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 823,500	$ 335,029	$ 837,571	$ 1,781,917	$ 3,180,778	$ 5,022,204
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Advanced Metering - Estimated Revenue Requirement Advanced Metering Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	$ -	$ 33,035,902	$ 94,361,455	$ 150,169,589	$ 151,892,128	$ 151,892,128
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	33,035,902	94,361,455	150,169,589	151,892,128	151,892,128
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	-	11,785,400	13,916,002	13,916,002	13,916,002	13,916,002
38				G&I Plant - Other	1,684,766	5,158,009	5,158,009	5,158,009	5,158,009	5,158,009
39			Total General & Intangible Plant		1,684,766	16,943,409	19,074,011	19,074,011	19,074,011	19,074,011
40										
41				**Total Gross Plant**	1,684,766	49,979,310	113,435,465	169,243,599	170,966,139	170,966,139
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	(509,927)	(3,694,861)	(9,808,137)	(17,359,680)	(24,954,286)
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	(509,927)	(3,694,861)	(9,808,137)	(17,359,680)	(24,954,286)
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	(687,482)	(1,972,552)	(3,364,152)	(4,755,752)	(6,147,352)
75				G&I Plant - Other	-	(98,930)	(401,810)	(704,689)	(1,007,569)	(1,310,449)
76			Total General & Intangible Plant		-	(786,412)	(2,374,361)	(4,068,841)	(5,763,321)	(7,457,801)
77										
78				**Total Accumulated Depreciation**	-	(1,296,338)	(6,069,222)	(13,876,978)	(23,123,001)	(32,412,088)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	(820,844)	(3,377,395)	(7,538,637)	(11,468,251)	(14,191,384)
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	(820,844)	(3,377,395)	(7,538,637)	(11,468,251)	(14,191,384)
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	(514,969)	(1,381,409)	(2,211,844)	(2,050,932)	(1,710,801)
142				Total G&I ADIT - Other	(15,959)	(105,460)	(250,418)	(351,578)	(417,717)	(455,833)
143			Total General & Intangible ADIT		(15,959)	(620,430)	(1,631,827)	(2,563,422)	(2,468,649)	(2,166,633)
144										
145				**Total ADIT**	(15,959)	(1,441,273)	(5,009,222)	(10,102,059)	(13,936,901)	(16,358,018)
146										
147		**Total Rate Base**			**$ 1,668,807**	**$ 47,241,698**	**$ 102,357,021**	**$ 145,264,562**	**$ 133,906,237**	**$ 122,196,033**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			8,814	1,385,129	6,487,029	9,206,359	8,486,508	7,744,356
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	2,464,580	3,129,966	1,483,291	(309,643)	(2,181,698)	(6,034,122)
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		2,464,580	3,129,966	1,483,291	(309,643)	(2,181,698)	(6,034,122)
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	3,150,944	3,280,596	3,433,709	3,555,173	3,586,538	3,615,857
165				Other	88,714	-	-	88,714	-	-
166			Total General & Intagible O&M		3,239,658	3,280,596	3,433,709	3,643,886	3,586,538	3,615,857
167										
168			A&G							
169										
170				**Total O&M**	5,704,238	6,410,562	4,917,000	3,334,244	1,404,840	(2,418,265)
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Advanced Metering - Estimated Revenue Requirement Advanced Metering Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	509,927	3,184,934	6,113,276	7,551,543	7,594,606
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	509,927	3,184,934	6,113,276	7,551,543	7,594,606
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	687,482	1,285,070	1,391,600	1,391,600	1,391,600
204	G&I Depreciation Expense - Other	-	98,930	302,880	302,880	302,880	302,880
205	Total General & Intagible Depreciation Expense	-	786,412	1,587,950	1,694,480	1,694,480	1,694,480
206							
207	**Total Depreciation Expense**	-	1,296,338	4,772,884	7,807,756	9,246,023	9,289,086
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	278	357,786	997,333	1,543,976	1,479,857
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	278	357,786	997,333	1,543,976	1,479,857
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	-	122,077	131,378	116,070	100,763
221	Other	-	12,113	55,650	52,318	48,987	45,655
222	Total General & Intangible Property Tax	-	12,113	177,727	183,696	165,057	146,418
223							
224	**Total Property Taxes**	-	12,391	535,513	1,181,029	1,709,033	1,626,275
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	(1,903)	(299,143)	(1,400,988)	(1,988,275)	(1,832,811)	(1,672,530)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	-	48,908	180,070	294,569	348,832	350,457
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	-	48,908	180,070	294,569	348,832	350,457
235	Depreciation and AFUDC Debt	(62,831)	(5,611,473)	(14,047,041)	(20,050,542)	(15,097,800)	(9,531,958)
236	Deferred State Income Tax	3,501	312,632	782,602	1,117,075	841,143	531,053
237	Total Temporary Differences	(59,331)	(5,298,842)	(13,264,439)	(18,933,467)	(14,256,657)	(9,000,905)
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	(12,459)	1,112,757	2,785,532	3,976,028	2,993,898	1,890,190
240							
241	Net Taxable Equity Return	(64,880)	(3,051,191)	(5,212,795)	(7,444,786)	(4,260,230)	(688,432)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	(17,247)	(811,077)	(1,385,681)	(1,978,995)	(1,132,467)	(183,001)
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	(12,459)	1,112,757	2,785,532	3,976,028	2,993,898	1,890,190
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	(29,706)	301,680	1,399,851	1,997,033	1,861,431	1,707,189
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	(82,126)	(3,862,268)	(6,598,476)	(9,423,782)	(5,392,697)	(871,433)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	(2,984)	(227,874)	(389,310)	(556,003)	(318,169)	(51,415)
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	3,501	312,632	782,602	1,117,075	841,143	531,053
257	**Total State Income Tax**	516	84,758	393,292	561,071	522,974	479,639
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
261	**Total Revenue Credits**	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
262							
263	**Total Revenue Requirement Before Revenue Tax**	5,715,405	9,484,330	18,492,001	24,075,210	22,639,413	17,836,885
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	29,067	48,235	94,045	122,440	115,138	90,714
266							
267	**Total Revenue Requirement**	**$ 5,744,472**	**$ 9,532,565**	**$ 18,586,046**	**$ 24,197,650**	**$ 22,754,551**	**$ 17,927,599**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	8,814	1,385,129	6,487,029	9,206,359	8,486,508	7,744,356
271	O&M	5,704,238	6,410,562	4,917,000	3,334,244	1,404,840	(2,418,265)
272	Depreciation Expense	-	1,296,338	4,772,884	7,807,756	9,246,023	9,289,086
273	Taxes Other Than Income	29,067	60,626	629,558	1,303,469	1,824,171	1,716,988
274	Net Allowable Federal Income Tax	1,837	301,680	1,399,851	1,997,033	1,861,431	1,707,189
275	Net Allowable State Income Tax	516	84,758	393,292	561,071	522,974	479,639
276	Revenue Credits	-	(6,527)	(13,568)	(12,281)	(591,395)	(591,395)
277	**Total Revenue Requirement**	$ 5,744,472	$ 9,532,565	$ 18,586,046	$ 24,197,650	$ 22,754,551	$ 17,927,599
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Customer Information & Analytics - Estimated Revenue Requirement Customer Information & Analytics Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	$ -	$ 521,989	$ 521,989	$ 521,989	$ 521,989	$ 521,989
38				G&I Plant - Other	-	-	-	-	-	-
39			Total General & Intangible Plant		-	521,989	521,989	521,989	521,989	521,989
40										
41				**Total Gross Plant**	-	521,989	521,989	521,989	521,989	521,989
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	(34,799)	(86,998)	(139,197)	(191,396)	(243,595)
75				G&I Plant - Other	-	-	-	-	-	-
76			Total General & Intangible Plant		-	(34,799)	(86,998)	(139,197)	(191,396)	(243,595)
77										
78				**Total Accumulated Depreciation**	-	(34,799)	(86,998)	(139,197)	(191,396)	(243,595)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	(25,222)	(56,371)	(87,521)	(74,762)	(62,004)
142				Total G&I ADIT - Other	-	-	-	-	-	-
143			Total General & Intangible ADIT		-	(25,222)	(56,371)	(87,521)	(74,762)	(62,004)
144										
145				**Total ADIT**	-	(25,222)	(56,371)	(87,521)	(74,762)	(62,004)
146										
147		**Total Rate Base**			**$ -**	**$ 461,968**	**$ 378,619**	**$ 295,271**	**$ 255,830**	**$ 216,390**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			-	23,244	23,996	18,713	16,214	13,714
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	1,390,214	1,404,781	1,420,003	1,435,911	1,452,534
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		-	1,390,214	1,404,781	1,420,003	1,435,911	1,452,534
167										
168			A&G							
169										
170				**Total O&M**	-	1,390,214	1,404,781	1,420,003	1,435,911	1,452,534
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Customer Information & Analytics - Estimated Revenue Requirement Customer Information & Analytics Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	34,799	52,199	52,199	52,199	52,199
204	G&I Depreciation Expense - Other	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	34,799	52,199	52,199	52,199	52,199
206							
207	**Total Depreciation Expense**	-	34,799	52,199	52,199	52,199	52,199
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	3,828	5,359	4,785	4,211	3,637
221	Other	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	3,828	5,359	4,785	4,211	3,637
223							
224	**Total Property Taxes**	-	3,828	5,359	4,785	4,211	3,637
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	-	(5,020)	(5,182)	(4,041)	(3,502)	(2,962)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	-	1,313	1,969	1,969	1,969	1,969
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	-	1,313	1,969	1,969	1,969	1,969
235	Depreciation and AFUDC Debt	-	(99,297)	(122,636)	(122,636)	50,230	50,230
236	Deferred State Income Tax	-	5,532	6,832	6,832	(2,798)	(2,798)
237	Total Temporary Differences	-	(93,765)	(115,804)	(115,804)	47,431	47,431
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	-	19,691	24,319	24,319	(9,961)	(9,961)
240							
241	Net Taxable Equity Return	-	(54,537)	(70,702)	(74,844)	52,152	50,192
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	(14,497)	(18,794)	(19,895)	13,863	13,342
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	19,691	24,319	24,319	(9,961)	(9,961)
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	-	5,193	5,524	4,424	3,903	3,382
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	-	(69,035)	(89,497)	(94,739)	66,015	63,534
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	(4,073)	(5,280)	(5,590)	3,895	3,749
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	-	5,532	6,832	6,832	(2,798)	(2,798)
257	**Total State Income Tax**	-	1,459	1,552	1,243	1,096	950
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	-	1,458,737	1,493,411	1,501,367	1,513,533	1,526,416
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	-	7,419	7,595	7,636	7,697	7,763
266							
267	**Total Revenue Requirement**	**$ -**	**$ 1,466,156**	**$ 1,501,006**	**$ 1,509,002**	**$ 1,521,231**	**$ 1,534,179**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	-	23,244	23,996	18,713	16,214	13,714
271	O&M	-	1,390,214	1,404,781	1,420,003	1,435,911	1,452,534
272	Depreciation Expense	-	34,799	52,199	52,199	52,199	52,199
273	Taxes Other Than Income	-	11,247	12,954	12,420	11,908	11,399
274	Net Allowable Federal Income Tax	-	5,193	5,524	4,424	3,903	3,382
275	Net Allowable State Income Tax	-	1,459	1,552	1,243	1,096	950
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 1,466,156	$ 1,501,006	$ 1,509,002	$ 1,521,231	$ 1,534,179
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Cybersecurity - Estimated Revenue Requirement Cybersecurity Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	$ 69,295	$ 3,810,065	$ 4,020,727	$ 4,231,201	$ 4,448,342	$ 4,448,342
38				G&I Plant - Other	-	321,329	321,329	321,329	321,329	321,329
39			Total General & Intangible Plant		69,295	4,131,394	4,342,056	4,552,530	4,769,671	4,769,671
40										
41				**Total Gross Plant**	69,295	4,131,394	4,342,056	4,552,530	4,769,671	4,769,671
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	(4,620)	(107,521)	(499,060)	(911,657)	(1,345,634)	(1,790,468)
75				G&I Plant - Other	-	(12,579)	(31,448)	(50,316)	(69,185)	(88,053)
76			Total General & Intangible Plant		(4,620)	(120,100)	(530,508)	(961,973)	(1,414,818)	(1,878,521)
77										
78				**Total Accumulated Depreciation**	(4,620)	(120,100)	(530,508)	(961,973)	(1,414,818)	(1,878,521)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	(3,348)	(102,839)	(346,335)	(596,559)	(545,193)	(472,437)
142				Total G&I ADIT - Other	-	(15,376)	(25,360)	(32,425)	(37,154)	(40,019)
143			Total General & Intangible ADIT		(3,348)	(118,215)	(371,695)	(628,984)	(582,347)	(512,456)
144										
145				**Total ADIT**	(3,348)	(118,215)	(371,695)	(628,984)	(582,347)	(512,456)
146										
147		**Total Rate Base**			**$ 61,327**	**$ 3,893,080**	**$ 3,439,853**	**$ 2,961,573**	**$ 2,772,506**	**$ 2,378,694**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			3,086	93,848	218,006	187,694	175,712	150,753
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	217,350	228,218	239,628	251,610	264,190
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		-	217,350	228,218	239,628	251,610	264,190
167										
168			A&G							
169										
170				**Total O&M**	-	217,350	228,218	239,628	251,610	264,190
171										

	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Cybersecurity - Estimated Revenue Requirement Cybersecurity Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	4,620	102,901	391,540	412,596	433,977	444,834
204	G&I Depreciation Expense - Other	-	12,579	18,869	18,869	18,869	18,869
205	Total General & Intagible Depreciation Expense	4,620	115,480	410,408	431,465	452,846	463,703
206							
207	**Total Depreciation Expense**	4,620	115,480	410,408	431,465	452,846	463,703
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	508	10,803	40,728	38,738	36,515	34,130
221	Other	-	2,356	3,396	3,189	2,981	2,774
222	Total General & Intangible Property Tax	508	13,159	44,124	41,927	39,496	36,903
223							
224	**Total Property Taxes**	508	13,159	44,124	41,927	39,496	36,903
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	(666)	(20,268)	(47,082)	(40,536)	(37,948)	(32,558)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	174	4,357	15,484	16,278	17,085	17,494
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	174	4,357	15,484	16,278	17,085	17,494
235	Depreciation and AFUDC Debt	(13,182)	(452,232)	(997,953)	(1,012,948)	183,609	275,162
236	Deferred State Income Tax	734	25,195	55,599	56,434	(10,229)	(15,330)
237	Total Temporary Differences	(12,448)	(427,037)	(942,354)	(956,514)	173,379	259,832
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	2,614	89,678	197,894	200,868	(36,410)	(54,565)
240							
241	Net Taxable Equity Return	(7,240)	(259,422)	(558,052)	(592,209)	291,818	340,957
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	(1,925)	(68,960)	(148,343)	(157,423)	77,572	90,634
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	2,614	89,678	197,894	200,868	(36,410)	(54,565)
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	689	20,717	49,551	43,445	41,162	36,070
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	(9,165)	(328,382)	(706,395)	(749,632)	369,390	431,591
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	(541)	(19,375)	(41,677)	(44,228)	21,794	25,464
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	734	25,195	55,599	56,434	(10,229)	(15,330)
257	**Total State Income Tax**	194	5,821	13,922	12,206	11,565	10,134
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	9,097	466,375	964,229	956,365	972,390	961,753
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	46	2,372	4,904	4,864	4,945	4,891
266							
267	**Total Revenue Requirement**	**$ 9,143**	**$ 468,747**	**$ 969,132**	**$ 961,229**	**$ 977,336**	**$ 966,644**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	3,086	93,848	218,006	187,694	175,712	150,753
271	O&M	-	217,350	228,218	239,628	251,610	264,190
272	Depreciation Expense	4,620	115,480	410,408	431,465	452,846	463,703
273	Taxes Other Than Income	554	15,531	49,028	46,791	44,441	41,795
274	Net Allowable Federal Income Tax	689	20,717	49,551	43,445	41,162	36,070
275	Net Allowable State Income Tax	194	5,821	13,922	12,206	11,565	10,134
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 9,143	$ 468,747	$ 969,132	$ 961,229	$ 977,336	$ 966,644
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Data Management & Architecture - Estimated Revenue Requirement Data Management & Architecture Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	$ 2,864,801	$ 4,443,406	$ 5,534,132	$ 6,623,880	$ 6,623,880	$ 6,623,880
38				G&I Plant - Other	-	-	-	-	-	-
39			Total General & Intangible Plant		2,864,801	4,443,406	5,534,132	6,623,880	6,623,880	6,623,880
40										
41				**Total Gross Plant**	2,864,801	4,443,406	5,534,132	6,623,880	6,623,880	6,623,880
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	(47,747)	(434,411)	(933,288)	(1,541,189)	(2,203,577)	(2,865,965)
75				G&I Plant - Other	-	-	-	-	-	-
76			Total General & Intangible Plant		(47,747)	(434,411)	(933,288)	(1,541,189)	(2,203,577)	(2,865,965)
77										
78				**Total Accumulated Depreciation**	(47,747)	(434,411)	(933,288)	(1,541,189)	(2,203,577)	(2,865,965)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	(58,965)	(291,350)	(640,030)	(812,747)	(834,262)	(764,029)
142				Total G&I ADIT - Other	-	-	-	-	-	-
143			Total General & Intangible ADIT		(58,965)	(291,350)	(640,030)	(812,747)	(834,262)	(764,029)
144										
145				**Total ADIT**	(58,965)	(291,350)	(640,030)	(812,747)	(834,262)	(764,029)
146										
147		**Total Rate Base**			**$ 2,758,089**	**$ 3,717,645**	**$ 3,960,814**	**$ 4,269,945**	**$ 3,586,042**	**$ 2,993,887**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			44,288	225,589	251,023	270,614	227,271	189,742
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	698,330	1,545,614	1,787,807	1,858,188	1,931,479
165				Other	1,105,229	1,154,233	442,092	461,693	482,177	503,582
166			Total General & Intagible O&M		1,105,229	1,852,563	1,987,705	2,249,500	2,340,365	2,435,061
167										
168			A&G							
169										
170				**Total O&M**	1,105,229	1,852,563	1,987,705	2,249,500	2,340,365	2,435,061
171										

	A / B / C / D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Data Management & Architecture - Estimated Revenue Requirement Data Management & Architecture Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	47,747	386,664	498,877	607,901	662,388	662,388
204	G&I Depreciation Expense - Other	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	47,747	386,664	498,877	607,901	662,388	662,388
206							
207	**Total Depreciation Expense**	47,747	386,664	498,877	607,901	662,388	662,388
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	27,772	44,099	50,609	55,910	48,623
221	Other	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	27,772	44,099	50,609	55,910	48,623
223							
224	**Total Property Taxes**	-	27,772	44,099	50,609	55,910	48,623
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	(9,565)	(48,720)	(54,213)	(58,444)	(49,083)	(40,978)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	1,801	14,588	18,822	22,935	24,990	24,990
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	1,801	14,588	18,822	22,935	24,990	24,990
235	Depreciation and AFUDC Debt	(232,144)	(914,902)	(1,372,757)	(679,989)	(84,705)	276,508
236	Deferred State Income Tax	12,933	50,972	76,480	37,884	4,719	(15,405)
237	Total Temporary Differences	(219,211)	(863,930)	(1,296,276)	(642,104)	(79,986)	261,103
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	(46,034)	181,425	272,218	134,842	16,797	(54,832)
240							
241	Net Taxable Equity Return	(228,721)	(491,048)	(808,427)	(272,157)	139,990	380,026
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	(60,799)	(130,532)	(214,898)	(72,346)	37,212	101,020
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	(46,034)	181,425	272,218	134,842	16,797	(54,832)
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	(106,834)	50,893	57,320	62,496	54,009	46,188
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	(289,520)	(621,580)	(1,023,325)	(344,503)	177,202	481,046
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	(10,206)	(36,673)	(60,376)	(20,326)	10,455	28,382
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	12,933	50,972	76,480	37,884	4,719	(15,405)
257	**Total State Income Tax**	2,728	14,299	16,104	17,558	15,174	12,977
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	1,209,700	2,557,780	2,855,127	3,258,679	3,355,117	3,394,979
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	6,152	13,008	14,520	16,573	17,063	17,266
266							
267	**Total Revenue Requirement**	**$ 1,215,852**	**$ 2,570,789**	**$ 2,869,648**	**$ 3,275,252**	**$ 3,372,180**	**$ 3,412,245**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	44,288	225,589	251,023	270,614	227,271	189,742
271	O&M	1,105,229	1,852,563	1,987,705	2,249,500	2,340,365	2,435,061
272	Depreciation Expense	47,747	386,664	498,877	607,901	662,388	662,388
273	Taxes Other Than Income	6,152	40,781	58,619	67,182	72,973	65,889
274	Net Allowable Federal Income Tax	9,709	50,893	57,320	62,496	54,009	46,188
275	Net Allowable State Income Tax	2,728	14,299	16,104	17,558	15,174	12,977
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 1,215,852	$ 2,570,789	$ 2,869,648	$ 3,275,252	$ 3,372,180	$ 3,412,245
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Distribution Planning & Engineering - Estimated Revenue Requirement Distribution Planning & Engineering Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	$ -	$ -	$ 1,386,084	$ 8,845,448	$ 8,845,448	$ 8,845,448
38				G&I Plant - Other	-	-	-	-	-	-
39			Total General & Intangible Plant		-	-	1,386,084	8,845,448	8,845,448	8,845,448
40										
41				**Total Gross Plant**	-	-	1,386,084	8,845,448	8,845,448	8,845,448
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	-	(69,304)	(580,881)	(1,465,426)	(2,349,970)
75				G&I Plant - Other	-	-	-	-	-	-
76			Total General & Intangible Plant		-	-	(69,304)	(580,881)	(1,465,426)	(2,349,970)
77										
78				**Total Accumulated Depreciation**	-	-	(69,304)	(580,881)	(1,465,426)	(2,349,970)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	-	(106,137)	(760,041)	(1,287,892)	(1,699,150)
142				Total G&I ADIT - Other	-	-	-	-	-	-
143			Total General & Intangible ADIT		-	-	(106,137)	(760,041)	(1,287,892)	(1,699,150)
144										
145				**Total ADIT**	-	-	(106,137)	(760,041)	(1,287,892)	(1,699,150)
146										
147		**Total Rate Base**			**$ -**	**$ -**	**$ 1,210,642**	**$ 7,504,526**	**$ 6,092,131**	**$ 4,796,328**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			-	-	76,726	475,611	386,098	303,974
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	382,007	598,905	622,563	647,196	672,845	699,552
159			Total Distribution O&M		382,007	598,905	622,563	647,196	672,845	699,552
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	22,000	22,660	23,340	24,040	24,761
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		-	22,000	22,660	23,340	24,040	24,761
167										
168			A&G							
169										
170				**Total O&M**	382,007	620,905	645,223	670,536	696,885	724,313
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Distribution Planning & Engineering - Estimated Revenue Requirement Distribution Planning & Engineering Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	-	69,304	511,577	884,545	884,545
204	G&I Depreciation Expense - Other	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	69,304	511,577	884,545	884,545
206							
207	**Total Depreciation Expense**	-	-	69,304	511,577	884,545	884,545
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	-	-	14,485	90,910	81,180
221	Other	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	14,485	90,910	81,180
223							
224	**Total Property Taxes**	-	-	-	14,485	90,910	81,180
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	-	-	(16,570)	(102,716)	(83,385)	(65,649)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	-	-	2,615	19,301	33,372	33,372
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	-	-	2,615	19,301	33,372	33,372
235	Depreciation and AFUDC Debt	-	-	(417,863)	(2,574,424)	(2,078,152)	(1,619,126)
236	Deferred State Income Tax	-	-	23,280	143,429	115,780	90,206
237	Total Temporary Differences	-	-	(394,583)	(2,430,996)	(1,962,372)	(1,528,920)
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	-	-	82,862	510,509	412,098	321,073
240							
241	Net Taxable Equity Return	-	-	(248,950)	(1,528,292)	(1,214,189)	(936,149)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	(66,177)	(406,255)	(322,759)	(248,850)
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	82,862	510,509	412,098	321,073
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	-	-	16,686	104,254	89,339	72,223
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	-	-	(315,126)	(1,934,547)	(1,536,948)	(1,184,999)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	(18,592)	(114,138)	(90,680)	(69,915)
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	-	-	23,280	143,429	115,780	90,206
257	**Total State Income Tax**	-	-	4,688	29,290	25,100	20,291
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	382,007	620,905	812,627	1,805,752	2,172,876	2,086,527
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	1,943	3,158	4,133	9,184	11,051	10,612
266							
267	**Total Revenue Requirement**	**$ 383,950**	**$ 624,063**	**$ 816,760**	**$ 1,814,936**	**$ 2,183,927**	**$ 2,097,139**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	-	-	76,726	475,611	386,098	303,974
271	O&M	382,007	620,905	645,223	670,536	696,885	724,313
272	Depreciation Expense	-	-	69,304	511,577	884,545	884,545
273	Taxes Other Than Income	1,943	3,158	4,133	23,668	101,961	91,792
274	Net Allowable Federal Income Tax	-	-	16,686	104,254	89,339	72,223
275	Net Allowable State Income Tax	-	-	4,688	29,290	25,100	20,291
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 383,950	$ 624,063	$ 816,760	$ 1,814,936	$ 2,183,927	$ 2,097,139
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Distribution Automation - Estimated Revenue Requirement Distribution Automation Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	$ -	$ 11,968,345	$ 28,119,194	$ 44,739,662	$ 62,401,128	$ 80,330,989
22			Total Distribution Plant		-	11,968,345	28,119,194	44,739,662	62,401,128	80,330,989
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	-	-	-	-	-	-
38				G&I Plant - Other	4,152,671	8,369,268	8,369,268	8,369,268	8,369,268	8,369,268
39			Total General & Intangible Plant		4,152,671	8,369,268	8,369,268	8,369,268	8,369,268	8,369,268
40										
41				**Total Gross Plant**	4,152,671	20,337,613	36,488,462	53,108,930	70,770,397	88,700,257
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	(219,491)	(770,872)	(1,773,005)	(3,246,666)	(5,209,867)
59			Total Distribution Plant		-	(219,491)	(770,872)	(1,773,005)	(3,246,666)	(5,209,867)
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	-	-	-	-	-
75				G&I Plant - Other	-	(243,846)	(735,292)	(1,226,738)	(1,718,184)	(2,209,629)
76			Total General & Intangible Plant		-	(243,846)	(735,292)	(1,226,738)	(1,718,184)	(2,209,629)
77										
78				**Total Accumulated Depreciation**	-	(463,337)	(1,506,164)	(2,999,743)	(4,964,850)	(7,419,496)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	(248,025)	(559,675)	(1,045,646)	(1,696,674)	(2,496,462)
111			Total Distribution ADIT		-	(248,025)	(559,675)	(1,045,646)	(1,696,674)	(2,496,462)
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	-	-	-	-	-
142				Total G&I ADIT - Other	(39,337)	(218,790)	(441,104)	(594,931)	(694,011)	(749,232)
143			Total General & Intangible ADIT		(39,337)	(218,790)	(441,104)	(594,931)	(694,011)	(749,232)
144										
145				**Total ADIT**	(39,337)	(466,816)	(1,000,778)	(1,640,577)	(2,390,685)	(3,245,694)
146										
147		**Total Rate Base**			**$ 4,113,335**	**$ 19,407,461**	**$ 33,981,519**	**$ 48,468,610**	**$ 63,414,861**	**$ 78,035,067**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			21,724	823,051	2,153,630	3,071,771	4,019,012	4,945,589
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	9,750	618,471	741,521	893,465	1,082,979	1,324,568
159			Total Distribution O&M		9,750	618,471	741,521	893,465	1,082,979	1,324,568
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	-	-	-	-	-
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		-	-	-	-	-	-
167										
168			A&G							
169										
170				**Total O&M**	9,750	618,471	741,521	893,465	1,082,979	1,324,568
171										

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Distribution Automation - Estimated Revenue Requirement Distribution Automation Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172		**Depreciation Expense**								
176			Production Depreciation Expense		-	-	-	-	-	-
177										
178			Distribution Depreciation Expense							
182				Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187				Distribution Depreciation Expense - Other	-	219,491	551,382	1,002,133	1,473,662	1,963,200
188			Distribution Depreciation Expense Total		-	219,491	551,382	1,002,133	1,473,662	1,963,200
189										
193			Total Transmission Depreciation Expense		-	-	-	-	-	-
194										
195			General & Intangible Depreciation Expense							
199				G&I Depreciation Expense - Software	-	-	-	-	-	-
204				G&I Depreciation Expense - Other	-	243,846	491,446	491,446	491,446	491,446
205			Total General & Intagible Depreciation Expense		-	243,846	491,446	491,446	491,446	491,446
206										
207				**Total Depreciation Expense**	-	463,337	1,042,827	1,493,579	1,965,107	2,454,646
208										
209		**Property Tax**								
210			Production Property Tax		-	-	-	-	-	-
211										
212			Distribution Property Tax							
213				Meters	-	-	-	-	-	-
214				Other	-	87,768	129,237	300,832	472,633	650,699
215			Total Distribution Property Tax		-	87,768	129,237	300,832	472,633	650,699
216										
217			Transmission Property Tax		-	-	-	-	-	-
218										
219			General & Intangible Property Tax							
220				Software	-	-	-	-	-	-
221				Other	-	29,857	89,380	83,974	78,568	73,162
222			Total General & Intangible Property Tax		-	29,857	89,380	83,974	78,568	73,162
223										
224				**Total Property Taxes**	-	117,625	218,617	384,805	551,201	723,861
225										
226		**Federal Income Tax**								
227		<u>Return Adjustments</u>								
228			Interest		(4,692)	(177,752)	(465,114)	(663,403)	(867,976)	(1,068,087)
229										
230		<u>Tax/Book Adjustments</u>								
231			AFUDC Equity Flow Through		-	17,481	39,344	56,349	74,139	92,608
232			R&D Credit Flow Through							
233			ITC Flow Through		-	-	-	-	-	-
234			Total Permanent Differences		-	17,481	39,344	56,349	74,139	92,608
235			Depreciation and AFUDC Debt		(154,868)	(1,682,988)	(2,102,216)	(2,518,892)	(2,953,183)	(3,366,176)
236			Deferred State Income Tax		8,628	93,764	117,121	140,335	164,530	187,540
237			Total Temporary Differences		(146,240)	(1,589,224)	(1,985,096)	(2,378,557)	(2,788,652)	(3,178,637)
238			Amortization of EDFIT							
239		Deferred Federal Income Taxes			(30,710)	333,737	416,870	499,497	585,617	667,514
240										
241		Net Taxable Equity Return			(159,918)	(592,707)	159,633	585,657	1,022,139	1,458,988
242			Federal Tax Rate		26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243			Total Current Federal Income Tax		(42,510)	(157,555)	42,434	155,681	271,708	387,832
244				Amortization of EDFIT	-	-	-	-	-	-
245				Total Provision for Federal Income Tax	(30,710)	333,737	416,870	499,497	585,617	667,514
246		Investment Tax Credits								
247			Investment Tax Credits							
248			R&D Credits							
249				**Total Federal Income Tax**	(73,220)	176,182	459,304	655,178	857,325	1,055,346
250										
251		**State Income Tax**								
252			Net Current Taxable Equity Return		(202,428)	(750,263)	202,068	741,338	1,293,847	1,846,820
253			State Tax Rate		5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254				Total Current State Income Tax	(7,356)	(44,265)	11,922	43,739	76,337	108,962
255			Amortization of EDSIT							
256			Total Deferred State Income Tax		8,628	93,764	117,121	140,335	164,530	187,540
257				**Total State Income Tax**	1,272	49,499	129,043	184,074	240,867	296,502
258										
259		**Revenue Credits**								
260			Opt-out Fee Revenue		-	-				
261				**Total Revenue Credits**	-	-	-	-	-	-
262										
263			**Total Revenue Requirement Before Revenue Tax**		37,274	2,248,164	4,744,942	6,682,871	8,716,492	10,800,512
264				Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265				**Revenue Tax**	190	11,434	24,132	33,987	44,330	54,929
266										
267		**Total Revenue Requirement**			**$ 37,463**	**$ 2,259,597**	**$ 4,769,073**	**$ 6,716,859**	**$ 8,760,822**	**$ 10,855,441**
268										
269		**Revenue Requirement Summary**								
270			Return on Rate Base		21,724	823,051	2,153,630	3,071,771	4,019,012	4,945,589
271			O&M		9,750	618,471	741,521	893,465	1,082,979	1,324,568
272			Depreciation Expense		-	463,337	1,042,827	1,493,579	1,965,107	2,454,646
273			Taxes Other Than Income		190	129,058	242,749	418,793	595,531	778,790
274			Net Allowable Federal Income Tax		4,528	176,182	459,304	655,178	857,325	1,055,346
275			Net Allowable State Income Tax		1,272	49,499	129,043	184,074	240,867	296,502
276			Revenue Credits		-	-	-	-	-	-
277				**Total Revenue Requirement**	$ 37,463	$ 2,259,597	$ 4,769,073	$ 6,716,859	$ 8,760,822	$ 10,855,441
278										
279		*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.								

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Telecommunications - Estimated Revenue Requirement Telecommunications Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		-	-	-	-	-	-
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	-	-	-	-	-	-
38				G&I Plant - Other	$ 182,938	$ 8,064,320	$ 16,099,026	$ 24,169,864	$ 32,496,411	$ 40,694,475
39			Total General & Intangible Plant		182,938	8,064,320	16,099,026	24,169,864	32,496,411	40,694,475
40										
41				**Total Gross Plant**	182,938	8,064,320	16,099,026	24,169,864	32,496,411	40,694,475
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	-	-	-	-	-
75				G&I Plant - Other	(1,790)	(19,167)	(728,607)	(1,910,907)	(3,574,637)	(5,723,532)
76			Total General & Intangible Plant		(1,790)	(19,167)	(728,607)	(1,910,907)	(3,574,637)	(5,723,532)
77										
78				**Total Accumulated Depreciation**	(1,790)	(19,167)	(728,607)	(1,910,907)	(3,574,637)	(5,723,532)
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	-	-	-	-	-
142				Total G&I ADIT - Other	(2,298)	(88,603)	(520,187)	(1,129,308)	(1,863,677)	(2,675,524)
143			Total General & Intangible ADIT		(2,298)	(88,603)	(520,187)	(1,129,308)	(1,863,677)	(2,675,524)
144										
145				**Total ADIT**	(2,298)	(88,603)	(520,187)	(1,129,308)	(1,863,677)	(2,675,524)
146										
147		**Total Rate Base**			**$ 178,850**	**$ 7,956,550**	**$ 14,850,232**	**$ 21,129,649**	**$ 27,058,097**	**$ 32,295,419**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			2,854	58,726	941,156	1,339,123	1,714,847	2,046,770
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	1,364	1,364	1,364	1,364	1,364	1,364
165				Other	382,007	398,905	764,014	797,810	833,126	870,032
166			Total General & Intagible O&M		383,371	400,269	765,378	799,174	834,490	871,396
167										
168			A&G							
169										
170				**Total O&M**	383,371	400,269	765,378	799,174	834,490	871,396
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Telecommunications - Estimated Revenue Requirement Telecommunications Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	1,790	17,377	709,439	1,182,300	1,663,730	2,148,895
205	Total General & Intagible Depreciation Expense	1,790	17,377	709,439	1,182,300	1,663,730	2,148,895
206							
207	**Total Depreciation Expense**	1,790	17,377	709,439	1,182,300	1,663,730	2,148,895
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	-	-	-	-	-
221	Other	-	2,545	88,497	169,075	244,849	318,140
222	Total General & Intangible Property Tax	-	2,545	88,497	169,075	244,849	318,140
223							
224	**Total Property Taxes**	-	2,545	88,497	169,075	244,849	318,140
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	(616)	(12,683)	(203,259)	(289,207)	(370,351)	(442,036)
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	68	656	26,766	44,606	62,769	81,073
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	68	656	26,766	44,606	62,769	81,073
235	Depreciation and AFUDC Debt	(9,046)	(339,785)	(1,699,151)	(2,398,114)	(2,891,214)	(3,196,248)
236	Deferred State Income Tax	504	18,930	94,665	133,606	161,078	178,072
237	Total Temporary Differences	(8,542)	(320,855)	(1,604,486)	(2,264,508)	(2,730,136)	(3,018,175)
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	(1,794)	67,379	336,942	475,547	573,329	633,817
240							
241	Net Taxable Equity Return	(8,031)	(206,776)	(502,882)	(694,440)	(749,543)	(698,551)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	(2,135)	(54,966)	(133,678)	(184,598)	(199,246)	(185,691)
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	(1,794)	67,379	336,942	475,547	573,329	633,817
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	(3,929)	12,414	203,264	290,949	374,083	448,126
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	(10,165)	(261,742)	(636,559)	(879,038)	(948,789)	(884,242)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	(332)	(15,443)	(37,557)	(51,863)	(55,979)	(52,170)
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	504	18,930	94,665	133,606	161,078	178,072
257	**Total State Income Tax**	172	3,488	57,108	81,743	105,100	125,902
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	388,801	494,818	2,764,842	3,862,363	4,937,099	5,959,229
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	1,977	2,517	14,061	19,643	25,109	30,307
266							
267	**Total Revenue Requirement**	**$ 390,778**	**$ 497,335**	**$ 2,778,903**	**$ 3,882,006**	**$ 4,962,207**	**$ 5,989,536**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	2,854	58,726	941,156	1,339,123	1,714,847	2,046,770
271	O&M	383,371	400,269	765,378	799,174	834,490	871,396
272	Depreciation Expense	1,790	17,377	709,439	1,182,300	1,663,730	2,148,895
273	Taxes Other Than Income	1,977	5,062	102,558	188,718	269,957	348,447
274	Net Allowable Federal Income Tax	613	12,414	203,264	290,949	374,083	448,126
275	Net Allowable State Income Tax	172	3,488	57,108	81,743	105,100	125,902
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 390,778	$ 497,335	$ 2,778,903	$ 3,882,006	$ 4,962,207	$ 5,989,536
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

	A	B	C	D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**									
2	**WP Program Oversight - Estimated Revenue Requirement Program Oversight Project**									
3										
4					**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5					**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
6		**Gross Plant**								
10			Production Plant		$ -	$ -	$ -	$ -	$ -	$ -
11										
12			Distribution Plant							
16				Distribution Plant - Meters	-	-	-	-	-	-
21				Distribution Plant - Other	-	-	-	-	-	-
22			Total Distribution Plant		-	-	-	-	-	-
23										
27			Transmission Plant		-	-	-	-	-	-
28										
29			General & Intangible Plant							
33				G&I - Software	-	-	-	-	-	-
38				G&I Plant - Other	-	-	-	-	-	-
39			Total General & Intangible Plant		-	-	-	-	-	-
40										
41				**Total Gross Plant**	-	-	-	-	-	-
42										
43		**Accumulated Depreciation**								
47			Production Plant		-	-	-	-	-	-
48										
49			Distribution Plant							
53				Distribution Plant - Meters	-	-	-	-	-	-
58				Distribution Plant - Other	-	-	-	-	-	-
59			Total Distribution Plant		-	-	-	-	-	-
60										
64			Transmission Plant		-	-	-	-	-	-
65										
66			General & Intangible Plant							
70				G&I - Software	-	-	-	-	-	-
75				G&I Plant - Other	-	-	-	-	-	-
76			Total General & Intangible Plant		-	-	-	-	-	-
77										
78				**Total Accumulated Depreciation**	-	-	-	-	-	-
79										
80		**ADIT**								
89			Total Production ADIT		-	-	-	-	-	-
90										
91			Distribution ADIT							
100				Total Distribution ADIT - Meters	-	-	-	-	-	-
110				Total Distribution ADIT - Other	-	-	-	-	-	-
111			Total Distribution ADIT		-	-	-	-	-	-
112										
121			Total Transmission ADIT		-	-	-	-	-	-
122										
123			General & Intangible ADIT							
132				Total G&I ADIT - Software	-	-	-	-	-	-
142				Total G&I ADIT - Other	-	-	-	-	-	-
143			Total General & Intangible ADIT		-	-	-	-	-	-
144										
145				**Total ADIT**	-	-	-	-	-	-
146										
147		**Total Rate Base**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
148										
149		**Weighted Average Cost of Capital**			6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150										
151		**Return on Rate Base**			-	-	-	-	-	-
152										
153		**O&M**								
154			Production O&M		-	-	-	-	-	-
155										
156			Distribution O&M							
157				Meters	-	-	-	-	-	-
158				Other	-	-	-	-	-	-
159			Total Distribution O&M		-	-	-	-	-	-
160										
161			Transmission O&M		-	-	-	-	-	-
162										
163			General & Intangible O&M							
164				Software	-	-	-	-	-	-
165				Other	-	-	-	-	-	-
166			Total General & Intagible O&M		-	-	-	-	-	-
167										
168			A&G		1,182,863	1,235,148	1,289,787	1,346,884	1,406,550	1,468,902
169										
170				**Total O&M**	1,182,863	1,235,148	1,289,787	1,346,884	1,406,550	1,468,902
171										

	A B C D	R	AE	AF	AG	AH	AI
1	**PNM Exhibit KTS-3**						
2	**WP Program Oversight - Estimated Revenue Requirement Program Oversight Project**						
3							
4		**Year 1***	**Year 2***	**Year 3**	**Year 4**	**Year 5**	**Year 6**
5		**Sept 2023 - Aug 2024**	**Sept 2024 - Aug 2025**	**Sept 2025 - Aug 2026**	**Sept 2026 - Aug 2027**	**Sept 2027 - Aug 2028**	**Sept 2028 - Aug 2029**
172	**Depreciation Expense**						
176	Production Depreciation Expense	-	-	-	-	-	-
177							
178	Distribution Depreciation Expense						
182	Distribution Depreciation Expense - Meters	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other	-	-	-	-	-	-
188	Distribution Depreciation Expense Total	-	-	-	-	-	-
189							
193	Total Transmission Depreciation Expense	-	-	-	-	-	-
194							
195	General & Intangible Depreciation Expense						
199	G&I Depreciation Expense - Software	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-
206							
207	**Total Depreciation Expense**	-	-	-	-	-	-
208							
209	**Property Tax**						
210	Production Property Tax	-	-	-	-	-	-
211							
212	Distribution Property Tax						
213	Meters	-	-	-	-	-	-
214	Other	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-
216							
217	Transmission Property Tax	-	-	-	-	-	-
218							
219	General & Intangible Property Tax						
220	Software	-	-	-	-	-	-
221	Other	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-
223							
224	**Total Property Taxes**	-	-	-	-	-	-
225							
226	**Federal Income Tax**						
227	Return Adjustments						
228	Interest	-	-	-	-	-	-
229							
230	Tax/Book Adjustments						
231	AFUDC Equity Flow Through	-	-	-	-	-	-
232	R&D Credit Flow Through						
233	ITC Flow Through	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-
235	Depreciation and AFUDC Debt	-	-	-	-	-	-
236	Deferred State Income Tax	-	-	-	-	-	-
237	Total Temporary Differences	-	-	-	-	-	-
238	Amortization of EDFIT						
239	Deferred Federal Income Taxes	-	-	-	-	-	-
240							
241	Net Taxable Equity Return	-	-	-	-	-	-
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-
244	Amortization of EDFIT	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-
246	Investment Tax Credits						
247	Investment Tax Credits						
248	R&D Credits						
249	**Total Federal Income Tax**	-	-	-	-	-	-
250							
251	**State Income Tax**						
252	Net Current Taxable Equity Return	-	-	-	-	-	-
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-
255	Amortization of EDSIT						
256	Total Deferred State Income Tax	-	-	-	-	-	-
257	**Total State Income Tax**	-	-	-	-	-	-
258							
259	**Revenue Credits**						
260	Opt-out Fee Revenue	-	-				
261	**Total Revenue Credits**	-	-	-	-	-	-
262							
263	**Total Revenue Requirement Before Revenue Tax**	1,182,863	1,235,148	1,289,787	1,346,884	1,406,550	1,468,902
264	Revenue Tax Factor	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**	6,016	6,282	6,560	6,850	7,153	7,470
266							
267	**Total Revenue Requirement**	**$ 1,188,878**	**$ 1,241,430**	**$ 1,296,346**	**$ 1,353,734**	**$ 1,413,704**	**$ 1,476,372**
268							
269	**Revenue Requirement Summary**						
270	Return on Rate Base	-	-	-	-	-	-
271	O&M	1,182,863	1,235,148	1,289,787	1,346,884	1,406,550	1,468,902
272	Depreciation Expense	-	-	-	-	-	-
273	Taxes Other Than Income	6,016	6,282	6,560	6,850	7,153	7,470
274	Net Allowable Federal Income Tax	-	-	-	-	-	-
275	Net Allowable State Income Tax	-	-	-	-	-	-
276	Revenue Credits	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ 1,188,878	$ 1,241,430	$ 1,296,346	$ 1,353,734	$ 1,413,704	$ 1,476,372
278							
279	*Note: Year 1 and 2 Revenue Requirements reflect the sum of monthly totals. The electronic version of this worksheet uses the Microsoft Excel outline function. This function groups the monthly columns for print formatting purposes. For year 1 monthly activity, please refer to PNM Exhibit KTS-5.						

PNM Exhibit KTS-3
WP WACC - December 31, 2021 Year End Weighted Average Cost of Capital

Line No.	Capital Component	Total Capitalization Test Period	Percentage of Total Capitalization	Capital Component Cost	Weighted Average Cost
1	Long Term Debt	1,815,845	47.95%	2.85%	1.37%
2	Preferred Stock	11,529	0.30%	4.62%	0.01%
3	Common Equity	1,959,858	51.75%	9.575%	4.96%
4	Total	3,787,233	100.00%		6.34%
				Tax Rate	25.40%
				Tax Gross Up:	
				Debt	1.37%
				Preferred	0.02%
				Equity	6.64%
				Total	8.03%

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-4**														
2	**Total Grid Modernization Year 1 Revenue Requirement**														
3	**All Projects**														
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
7	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	AFUDC Equity - Production	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	AFUDC Debt Production	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	$ -	$ -	$ -	$ -	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 2,934,096	$ 2,934,096	$ 2,934,096	$ 2,934,096
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	182,938	182,938	6,020,375	6,020,375
39	Total General & Intangible Plant	-	-	-	-	69,295	69,295	69,295	69,295	69,295	69,295	3,117,034	3,117,034	8,954,471	8,954,471
40															
41	**Total Gross Plant**	-	-	-	-	69,295	69,295	69,295	69,295	69,295	69,295	3,117,034	3,117,034	8,954,471	8,954,471
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(27,916)	(52,366)	(52,366)
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	(895)	(1,790)	(1,790)
76	Total General & Intangible Plant	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(28,811)	(54,157)	(54,157)
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(28,811)	(54,157)	(54,157)
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(35,186)	(48,750)	(62,313)	(62,313)
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	(1,482)	(1,890)	(57,593)	(57,593)
143	Total General & Intangible ADIT	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(36,669)	(50,640)	(119,906)	(119,906)
144															
145	**Total ADIT**	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(36,669)	(50,640)	(119,906)	(119,906)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 68,510**	**$ 67,612**	**$ 66,714**	**$ 65,816**	**$ 64,918**	**$ 64,021**	**$ 3,076,901**	**$ 3,037,584**	**$ 8,780,408**	**$ 8,780,408**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	362	357	352	348	343	338	16,250	16,043	46,373	80,765
152															

Row	Description	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Year 1* Sept 2023 - Aug 2024
	A / B / C / D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-4**														
2	**Total Grid Modernization Year 1 Revenue Requirement**														
3	**All Projects**														
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	2,464,580
158	Other		32,646	32,646	32,646	32,646	32,646	32,646	32,646	32,646	32,646	32,646	32,646	32,646	391,757
159	Total Distribution O&M		238,028	238,028	238,028	238,028	238,028	238,028	238,028	238,028	238,028	238,028	238,028	238,028	2,856,337
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software	-	330,970	330,970	330,970	330,970	330,970	330,970	330,970	330,970	330,970	330,970	330,970	330,970	3,971,641
165	Other	-	131,329	131,329	131,329	131,329	131,329	131,329	131,329	131,329	131,329	131,329	131,329	131,329	1,575,950
166	Total General & Intagible O&M		462,299	462,299	462,299	462,299	462,299	462,299	462,299	462,299	462,299	462,299	462,299	462,299	5,547,591
167															
168	A&G		98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	1,182,863
169															
170	**Total O&M**		798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	9,586,791
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	577	577	577	577	577	577	24,451	24,451	52,366
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	895	895	1,790
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	577	577	577	577	577	577	25,346	25,346	54,157
206															
207	**Total Depreciation Expense**	-	-	-	-	-	577	577	577	577	577	577	25,346	25,346	54,157
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	64	64	64	64	64	64	64	64	508
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	64	64	64	64	64	64	64	64	508
223															
224	**Total Property Taxes**	-	-	-	-	-	64	64	64	64	64	64	64	64	508
225															

PNM Exhibit KTS-4
Page 2 of 3

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-4**														
2	**Total Grid Modernization Year 1 Revenue Requirement**														
3	**All Projects**														
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	(78)	(77)	(76)	(75)	(74)	(73)	(3,510)	(3,465)	(10,015)	(17,443)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	22	22	22	22	22	22	956	956	2,043
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	22	22	22	22	22	22	956	956	2,043
235	Depreciation and AFUDC Debt		-	-	-	(3,093)	(1,261)	(1,261)	(1,261)	(1,261)	(1,261)	(134,966)	(55,004)	(272,703)	(472,072)
236	Deferred State Income Tax	-	-	-	-	172	70	70	70	70	70	7,519	3,064	15,193	26,300
237	Total Temporary Differences	-	-	-	-	(2,921)	(1,191)	(1,191)	(1,191)	(1,191)	(1,191)	(127,447)	(51,939)	(257,510)	(445,771)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	613	250	250	250	250	250	26,764	10,907	54,077	93,612
240															
241	Net Taxable Equity Return	-	-	-	-	(2,024)	(639)	(643)	(646)	(650)	(654)	(87,921)	(27,498)	(166,119)	(286,793)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	(538)	(170)	(171)	(172)	(173)	(174)	(23,371)	(7,310)	(44,158)	(76,236)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	613	250	250	250	250	250	26,764	10,907	54,077	93,612
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	75	80	79	78	77	76	3,393	3,598	9,919	17,376
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	(2,562)	(809)	(814)	(818)	(823)	(828)	(111,292)	(34,807)	(210,277)	(363,030)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	(151)	(48)	(48)	(48)	(49)	(49)	(6,566)	(2,054)	(12,406)	(21,419)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	172	70	70	70	70	70	7,519	3,064	15,193	26,300
257	**Total State Income Tax**	-	-	-	-	21	23	22	22	22	21	953	1,011	2,787	4,882
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		798,899	798,899	798,899	799,358	800,000	799,994	799,988	799,982	799,976	820,136	844,960	883,387	9,744,479
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		4,063	4,063	4,063	4,065	4,069	4,069	4,069	4,068	4,068	4,171	4,297	4,493	49,558
266															
267	**Total Revenue Requirement**		**$ 802,962**	**$ 802,962**	**$ 802,962**	**$ 803,423**	**$ 804,069**	**$ 804,063**	**$ 804,057**	**$ 804,051**	**$ 804,045**	**$ 824,307**	**$ 849,257**	**$ 887,880**	**$ 9,794,037**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	362	357	352	348	343	338	16,250	16,043	46,373	80,765
271	O&M	-	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	798,899	9,586,791
272	Depreciation Expense	-	-	-	-	-	577	577	577	577	577	577	25,346	25,346	54,157
273	Taxes Other Than Income	-	4,063	4,063	4,063	4,065	4,132	4,132	4,132	4,132	4,132	4,235	4,361	4,556	50,066
274	Net Allowable Federal Income Tax	-	-	-	-	75	80	79	78	77	76	3,393	3,598	9,919	17,376
275	Net Allowable State Income Tax	-	-	-	-	21	23	22	22	22	21	953	1,011	2,787	4,882
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 802,962	$ 802,962	$ 802,962	$ 803,423	$ 804,069	$ 804,063	$ 804,057	$ 804,051	$ 804,045	$ 824,307	$ 849,257	$ 887,880	$ 9,794,037
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

PNM Exhibit KTS-5
Grid Modernization Estimated Year 1 Revenue Requirement By Project

Table of Contents

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP ADMS - Estimated Year 1 Revenue Requirement ADMS Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
146															
147	**Total Rate Base**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
152															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP ADMS - Estimated Year 1 Revenue Requirement ADMS Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	819,333
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	819,333
167															
168	A&G														
169															
170	**Total O&M**		68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	819,333
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

	Description	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Year 1* Sept 2023 - Aug 2024
	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP ADMS - Estimated Year 1 Revenue Requirement ADMS Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	-	-
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	819,333
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		347	347	347	347	347	347	347	347	347	347	347	347	4,167
266															
267	**Total Revenue Requirement**		**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 68,625**	**$ 823,500**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
271	O&M	-	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	68,278	819,333
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	347	347	347	347	347	347	347	347	347	347	347	347	4,167
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 68,625	$ 823,500
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Advanced Metering - Estimated Year 1 Revenue Requirement Advanced Metering Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,684,766	$ 1,684,766
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	1,684,766	1,684,766
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	1,684,766	1,684,766
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	(15,959)	(15,959)
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	(15,959)	(15,959)
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	(15,959)	(15,959)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,668,807**	**$ 1,668,807**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	8,814	8,814
152															

	A–D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Advanced Metering - Estimated Year 1 Revenue Requirement Advanced Metering Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	2,464,580
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	205,382	2,464,580
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		262,579	262,579	262,579	262,579	262,579	262,579	262,579	262,579	262,579	262,579	262,579	262,579	3,150,944
165	Other		7,393	7,393	7,393	7,393	7,393	7,393	7,393	7,393	7,393	7,393	7,393	7,393	88,714
166	Total General & Intagible O&M		269,971	269,971	269,971	269,971	269,971	269,971	269,971	269,971	269,971	269,971	269,971	269,971	3,239,658
167															
168	A&G														
169															
170	**Total O&M**		475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	5,704,238
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Advanced Metering - Estimated Year 1 Revenue Requirement Advanced Metering Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	(1,903)	(1,903)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	(62,831)	(62,831)
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	3,501	3,501
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	(59,331)	(59,331)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	12,459	(12,459)
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	(39,961)	(64,880)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	(10,623)	(17,247)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	12,459	(12,459)
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	1,837	(29,706)
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	(50,584)	(82,126)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	(2,984)	(2,984)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	3,501	3,501
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	516	516
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	486,520	5,715,405
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,474	29,067
266															
267	**Total Revenue Requirement**		**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 477,771**	**$ 488,994**	**$ 5,744,472**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	8,814	8,814
271	O&M	-	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	475,353	5,704,238
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,418	2,474	29,067
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	1,837	1,837
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	516	516
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 477,771	$ 488,994	$ 5,744,472
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

PNM Exhibit KTS-5
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	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Customer Information & Analytics - Estimated Year 1 Revenue Requirement Customer Information & Analytics Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
146															
147	**Total Rate Base**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
152															

Row	Line	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Year 1* Sept 2023 - Aug 2024
1	**PNM Exhibit KTS-5**														
2	**WP Customer Information & Analytics - Estimated Year 1 Revenue Requirement Customer Information & Analytics Project**														
3															
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
167															
168	A&G														
169															
170	**Total O&M**		-	-	-	-	-	-	-	-	-	-	-	-	-
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

PNM Exhibit KTS-5
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	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Customer Information & Analytics - Estimated Year 1 Revenue Requirement Customer Information & Analytics Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	-	-
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		-	-	-	-	-	-	-	-	-	-	-	-	-
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		-	-	-	-	-	-	-	-	-	-	-	-	-
266															
267	**Total Revenue Requirement**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
271	O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A-D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Cybersecurity - Estimated Year 1 Revenue Requirement Cybersecurity Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	$ -	$ -	$ -	$ -	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295	$ 69,295
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295
40															
41	**Total Gross Plant**	-	-	-	-	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295	69,295
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(4,042)	(4,620)	(4,620)
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(4,042)	(4,620)	(4,620)
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	(577)	(1,155)	(1,732)	(2,310)	(2,887)	(3,465)	(4,042)	(4,620)	(4,620)
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(2,708)	(3,028)	(3,348)	(3,348)
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(2,708)	(3,028)	(3,348)	(3,348)
144															
145	**Total ADIT**	-	-	-	-	(786)	(1,106)	(1,426)	(1,747)	(2,067)	(2,387)	(2,708)	(3,028)	(3,348)	(3,348)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 68,510**	**$ 67,612**	**$ 66,714**	**$ 65,816**	**$ 64,918**	**$ 64,021**	**$ 63,123**	**$ 62,225**	**$ 61,327**	**$ 61,327**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	362	357	352	348	343	338	333	329	324	3,086
152															

Row	A-D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Cybersecurity - Estimated Year 1 Revenue Requirement Cybersecurity Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
167															
168	A&G														
169															
170	**Total O&M**		-	-	-	-	-	-	-	-	-	-	-	-	-
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	577	577	577	577	577	577	577	577	4,620
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	577	577	577	577	577	577	577	577	4,620
206															
207	**Total Depreciation Expense**	-	-	-	-	-	577	577	577	577	577	577	577	577	4,620
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	64	64	64	64	64	64	64	64	508
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	64	64	64	64	64	64	64	64	508
223															
224	**Total Property Taxes**	-	-	-	-	-	64	64	64	64	64	64	64	64	508
225															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Cybersecurity - Estimated Year 1 Revenue Requirement Cybersecurity Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	(78)	(77)	(76)	(75)	(74)	(73)	(72)	(71)	(70)	(666)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	22	22	22	22	22	22	22	22	174
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	22	22	22	22	22	22	22	22	174
235	Depreciation and AFUDC Debt		-	-	-	(3,093)	(1,261)	(1,261)	(1,261)	(1,261)	(1,261)	(1,261)	(1,261)	(1,261)	(13,182)
236	Deferred State Income Tax	-	-	-	-	172	70	70	70	70	70	70	70	70	734
237	Total Temporary Differences	-	-	-	-	(2,921)	(1,191)	(1,191)	(1,191)	(1,191)	(1,191)	(1,191)	(1,191)	(1,191)	(12,448)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	613	250	250	250	250	250	250	250	250	2,614
240															
241	Net Taxable Equity Return	-	-	-	-	(2,024)	(639)	(643)	(646)	(650)	(654)	(658)	(661)	(665)	(7,240)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	(538)	(170)	(171)	(172)	(173)	(174)	(175)	(176)	(177)	(1,925)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	613	250	250	250	250	250	250	250	250	2,614
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	75	80	79	78	77	76	75	74	73	689
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	(2,562)	(809)	(814)	(818)	(823)	(828)	(832)	(837)	(842)	(9,165)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	(151)	(48)	(48)	(48)	(49)	(49)	(49)	(49)	(50)	(541)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	172	70	70	70	70	70	70	70	70	734
257	**Total State Income Tax**	-	-	-	-	21	23	22	22	22	21	21	21	21	194
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		-	-	-	458	1,101	1,095	1,089	1,083	1,077	1,071	1,065	1,059	9,097
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		-	-	-	2	6	6	6	6	5	5	5	5	46
266															
267	**Total Revenue Requirement**		**$ -**	**$ -**	**$ -**	**$ 461**	**$ 1,106**	**$ 1,100**	**$ 1,094**	**$ 1,088**	**$ 1,082**	**$ 1,076**	**$ 1,070**	**$ 1,064**	**$ 9,143**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	362	357	352	348	343	338	333	329	324	3,086
271	O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
272	Depreciation Expense	-	-	-	-	-	577	577	577	577	577	577	577	577	4,620
273	Taxes Other Than Income	-	-	-	-	2	69	69	69	69	69	69	69	69	554
274	Net Allowable Federal Income Tax	-	-	-	-	75	80	79	78	77	76	75	74	73	689
275	Net Allowable State Income Tax	-	-	-	-	21	23	22	22	22	21	21	21	21	194
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ -	$ -	$ -	$ 461	$ 1,106	$ 1,100	$ 1,094	$ 1,088	$ 1,082	$ 1,076	$ 1,070	$ 1,064	$ 9,143
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Data Management & Architecture - Estimated Year 1 Revenue Requirement Data Management & Architecture Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,864,801	$ 2,864,801	$ 2,864,801	$ 2,864,801
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	2,864,801	2,864,801	2,864,801	2,864,801
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	2,864,801	2,864,801	2,864,801	2,864,801
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	(23,873)	(47,747)	(47,747)
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	(23,873)	(47,747)	(47,747)
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	(23,873)	(47,747)	(47,747)
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	(32,479)	(45,722)	(58,965)	(58,965)
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	(32,479)	(45,722)	(58,965)	(58,965)
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	(32,479)	(45,722)	(58,965)	(58,965)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,832,322**	**$ 2,795,206**	**$ 2,758,089**	**$ 2,758,089**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	14,959	14,763	14,567	44,288
152															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Data Management & Architecture - Estimated Year 1 Revenue Requirement Data Management & Architecture Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	1,105,229
166	Total General & Intagible O&M		92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	1,105,229
167															
168	A&G														
169															
170	**Total O&M**		92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	1,105,229
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	23,873	23,873	47,747
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	23,873	23,873	47,747
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	23,873	23,873	47,747
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Data Management & Architecture - Estimated Year 1 Revenue Requirement Data Management & Architecture Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	(3,231)	(3,188)	(3,146)	(9,565)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	901	901	1,801
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	901	901	1,801
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	(127,870)	(52,137)	(52,137)	(232,144)
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	7,124	2,905	2,905	12,933
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	(120,746)	(49,233)	(49,233)	(219,211)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	25,357	10,339	10,339	(46,034)
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	(83,661)	(26,419)	(26,572)	(228,721)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	(22,239)	(7,023)	(7,064)	(60,799)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	25,357	10,339	10,339	(46,034)
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	3,118	3,316	3,275	(106,834)
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	(105,900)	(33,441)	(33,636)	(289,520)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	(6,248)	(1,973)	(1,985)	(10,206)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	7,124	2,905	2,905	12,933
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	876	932	920	2,728
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	111,054	134,986	134,738	1,209,700
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		468	468	468	468	468	468	468	468	468	565	687	685	6,152
266															
267	**Total Revenue Requirement**		**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 92,571**	**$ 111,619**	**$ 135,673**	**$ 135,423**	**$ 1,215,852**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	14,959	14,763	14,567	44,288
271	O&M	-	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	92,102	1,105,229
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	23,873	23,873	47,747
273	Taxes Other Than Income	-	468	468	468	468	468	468	468	468	468	565	687	685	6,152
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	3,118	3,316	3,275	9,709
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	876	932	920	2,728
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 92,571	$ 111,619	$ 135,673	$ 135,423	$ 1,215,852
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Distribution Planning & Engineering - Estimated Year 1 Revenue Requirement Distribution Planning & Engineering Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
146															
147	**Total Rate Base**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
152															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Distribution Planning & Engineering - Estimated Year 1 Revenue Requirement Distribution Planning & Engineering Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
159	Total Distribution O&M		31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
167															
168	A&G														
169															
170	**Total O&M**		31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

PNM Exhibit KTS-5
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PNM Exhibit KTS-5

WP Distribution Planning & Engineering - Estimated Year 1 Revenue Requirement Distribution Planning & Engineering Project

Row	Item	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Year 1* Sept 2023 - Aug 2024
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	-	-
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		162	162	162	162	162	162	162	162	162	162	162	162	1,943
266															
267	**Total Revenue Requirement**		**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 31,996**	**$ 383,950**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
271	O&M	-	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	162	162	162	162	162	162	162	162	162	162	162	162	1,943
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 31,996	$ 383,950
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Distribution Automation - Estimated Year 1 Revenue Requirement Distribution Automation Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,152,671	$ 4,152,671
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	4,152,671	4,152,671
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	4,152,671	4,152,671
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	(39,337)	(39,337)
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	(39,337)	(39,337)
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	(39,337)	(39,337)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,113,335**	**$ 4,113,335**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	21,724	21,724
152															

	A–D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Distribution Automation - Estimated Year 1 Revenue Requirement Distribution Automation Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		813	813	813	813	813	813	813	813	813	813	813	813	9,750
159	Total Distribution O&M		813	813	813	813	813	813	813	813	813	813	813	813	9,750
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
167															
168	A&G														
169															
170	**Total O&M**		813	813	813	813	813	813	813	813	813	813	813	813	9,750
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Distribution Automation - Estimated Year 1 Revenue Requirement Distribution Automation Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	(4,692)	(4,692)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	(154,868)	(154,868)
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	8,628	8,628
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	(146,240)	(146,240)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	30,710	(30,710)
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	(98,497)	(159,918)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	(26,183)	(42,510)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	30,710	(30,710)
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	4,528	(73,220)
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	(124,680)	(202,428)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	(7,356)	(7,356)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	8,628	8,628
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	1,272	1,272
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		813	813	813	813	813	813	813	813	813	813	813	28,336	37,274
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		4	4	4	4	4	4	4	4	4	4	4	144	190
266															
267	**Total Revenue Requirement**		**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 817**	**$ 28,480**	**$ 37,463**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	21,724	21,724
271	O&M	-	813	813	813	813	813	813	813	813	813	813	813	813	9,750
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	4	4	4	4	4	4	4	4	4	4	4	144	190
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	4,528	4,528
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	1,272	1,272
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 817	$ 28,480	$ 37,463
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

PNM Exhibit KTS-5
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	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Telecommunications - Estimated Year 1 Revenue Requirement Telecommunications Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 182,938	$ 182,938	$ 182,938	$ 182,938
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	182,938	182,938	182,938	182,938
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	182,938	182,938	182,938	182,938
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	(895)	(1,790)	(1,790)
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	(895)	(1,790)	(1,790)
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	(895)	(1,790)	(1,790)
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	(1,482)	(1,890)	(2,298)	(2,298)
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	(1,482)	(1,890)	(2,298)	(2,298)
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	(1,482)	(1,890)	(2,298)	(2,298)
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 181,456**	**$ 180,153**	**$ 178,850**	**$ 178,850**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	958	951	945	2,854
152															

	A-D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Telecommunications - Estimated Year 1 Revenue Requirement Telecommunications Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		114	114	114	114	114	114	114	114	114	114	114	114	1,364
165	Other		31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	31,834	382,007
166	Total General & Intagible O&M		31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	383,371
167															
168	A&G														
169															
170	**Total O&M**		31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	383,371
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	895	895	1,790
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	895	895	1,790
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	895	895	1,790
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

Row	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Telecommunications - Estimated Year 1 Revenue Requirement Telecommunications Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	(207)	(205)	(204)	(616)
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	34	34	68
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	34	34	68
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	(5,836)	(1,605)	(1,605)	(9,046)
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	325	89	89	504
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	(5,511)	(1,516)	(1,516)	(8,542)
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	1,157	318	318	(1,794)
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	(3,602)	(418)	(423)	(8,031)
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	(958)	(111)	(112)	(2,135)
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	1,157	318	318	(1,794)
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	200	207	206	(3,929)
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	(4,560)	(529)	(536)	(10,165)
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	(269)	(31)	(32)	(332)
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	325	89	89	504
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	56	58	58	172
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	33,162	34,060	34,051	388,801
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		162	162	162	162	162	162	162	162	162	169	173	173	1,977
266															
267	**Total Revenue Requirement**		**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 32,110**	**$ 33,330**	**$ 34,233**	**$ 34,224**	**$ 390,778**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	958	951	945	2,854
271	O&M	-	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	31,948	383,371
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	895	895	1,790
273	Taxes Other Than Income	-	162	162	162	162	162	162	162	162	162	169	173	173	1,977
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	200	207	206	613
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	56	58	58	172
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 32,110	$ 33,330	$ 34,233	$ 34,224	$ 390,778
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Program Oversight - Estimated Year 1 Revenue Requirement Program Oversight Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
6	**Gross Plant**														
10	Production Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Distribution Plant														
16	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
27	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28															
29	General & Intangible Plant														
33	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40															
41	**Total Gross Plant**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42															
43	**Accumulated Depreciation**														
47	Production Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48															
49	Distribution Plant														
53	Distribution Plant - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Distribution Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Total Distribution Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60															
64	Transmission Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65															
66	General & Intangible Plant														
70	G&I - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	G&I Plant - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Total General & Intangible Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77															
78	**Total Accumulated Depreciation**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79															
80	**ADIT**														
89	Total Production ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90															
91	Distribution ADIT														
100	Total Distribution ADIT - Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	Total Distribution ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Total Distribution ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112															
121	Total Transmission ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122															
123	General & Intangible ADIT														
132	Total G&I ADIT - Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Total G&I ADIT - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Total General & Intangible ADIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144															
145	**Total ADIT**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
146															
147	**Total Rate Base**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
148															
149	**Weighted Average Cost of Capital**	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%	6.34%
150															
151	**Return on Rate Base**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
152															

	A-D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**PNM Exhibit KTS-5**														
2	**WP Program Oversight - Estimated Year 1 Revenue Requirement Program Oversight Project**														
3															
4															**Year 1***
5		**Aug-2023**	**Sep-2023**	**Oct-2023**	**Nov-2023**	**Dec-2023**	**Jan-2024**	**Feb-2024**	**Mar-2024**	**Apr-2024**	**May-2024**	**Jun-2024**	**Jul-2024**	**Aug-2024**	**Sept 2023 - Aug 2024**
153	**O&M**														
154	Production O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
155															
156	Distribution O&M														
157	Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
158	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
159	Total Distribution O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
160															
161	Transmission O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
162															
163	General & Intangible O&M														
164	Software		-	-	-	-	-	-	-	-	-	-	-	-	-
165	Other		-	-	-	-	-	-	-	-	-	-	-	-	-
166	Total General & Intagible O&M		-	-	-	-	-	-	-	-	-	-	-	-	-
167															
168	A&G		98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	1,182,863
169															
170	**Total O&M**		98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	1,182,863
171															
172	**Depreciation Expense**														
176	Production Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
177															
178	Distribution Depreciation Expense														
182	Distribution Depreciation Expense - Meters		-	-	-	-	-	-	-	-	-	-	-	-	-
187	Distribution Depreciation Expense - Other		-	-	-	-	-	-	-	-	-	-	-	-	-
188	Distribution Depreciation Expense Total		-	-	-	-	-	-	-	-	-	-	-	-	-
189															
193	Total Transmission Depreciation Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
194															
195	General & Intangible Depreciation Expense														
199	G&I Depreciation Expense - Software		-	-	-	-	-	-	-	-	-	-	-	-	-
204	G&I Depreciation Expense - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
205	Total General & Intagible Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206															
207	**Total Depreciation Expense**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208															
209	**Property Tax**														
210	Production Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211															
212	Distribution Property Tax														
213	Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215	Total Distribution Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216															
217	Transmission Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
218															
219	General & Intangible Property Tax														
220	Software	-	-	-	-	-	-	-	-	-	-	-	-	-	-
221	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	Total General & Intangible Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223															
224	**Total Property Taxes**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
225															

	Description	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Jul-2024	Aug-2024	Year 1* Sept 2023 - Aug 2024
1	**PNM Exhibit KTS-5**														
2	**WP Program Oversight - Estimated Year 1 Revenue Requirement Program Oversight Project**														
226	**Federal Income Tax**														
227	Return Adjustments														
228	Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-
229															
230	Tax/Book Adjustments														
231	AFUDC Equity Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
232	R&D Credit Flow Through														
233	ITC Flow Through	-	-	-	-	-	-	-	-	-	-	-	-	-	-
234	Total Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Depreciation and AFUDC Debt		-	-	-	-	-	-	-	-	-	-	-	-	-
236	Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total Temporary Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
238	Amortization of EDFIT														
239	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
240															
241	Net Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
242	Federal Tax Rate	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%	26.58%
243	Total Current Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
244	Amortization of EDFIT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
245	Total Provision for Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Investment Tax Credits														
247	Investment Tax Credits														
248	R&D Credits														
249	**Total Federal Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
250															
251	**State Income Tax**														
252	Net Current Taxable Equity Return	-	-	-	-	-	-	-	-	-	-	-	-	-	-
253	State Tax Rate	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%	5.90%
254	Total Current State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
255	Amortization of EDSIT														
256	Total Deferred State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
257	**Total State Income Tax**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
258															
259	**Revenue Credits**														
260	Opt-out Fee Revenue														-
261	**Total Revenue Credits**		-	-	-	-	-	-	-	-	-	-	-	-	-
262															
263	**Total Revenue Requirement Before Revenue Tax**		98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	1,182,863
264	Revenue Tax Factor		0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%	0.508573%
265	**Revenue Tax**		501	501	501	501	501	501	501	501	501	501	501	501	6,016
266															
267	**Total Revenue Requirement**		**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 99,073**	**$ 1,188,878**
268															
269	**Revenue Requirement Summary**														
270	Return on Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
271	O&M	-	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	98,572	1,182,863
272	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Taxes Other Than Income	-	501	501	501	501	501	501	501	501	501	501	501	501	6,016
274	Net Allowable Federal Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Net Allowable State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Revenue Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	**Total Revenue Requirement**	$ -	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 99,073	$ 1,188,878
278															
279	*Note: Year 1 Revenue Requirement reflects the sum of monthly totals.														

PNM Exhibit KTS-5
WP WACC - December 31, 2021 Year End Weighted Average Cost of Capital

Line No.	Capital Component	Total Capitalization Test Period	Percentage of Total Capitalization	Capital Component Cost	Weighted Average Cost
1	Long Term Debt	1,815,845	47.95%	2.85%	1.37%
2	Preferred Stock	11,529	0.30%	4.62%	0.01%
3	Common Equity	1,959,858	51.75%	9.575%	4.96%
4	Total	3,787,233	100.00%		6.34%
				Tax Rate	25.40%
				Tax Gross Up:	
				Debt	1.37%
				Preferred	0.02%
				Equity	6.64%
				Total	8.03%

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

SELF AFFIRMATION

KYLE T. SANDERS, Director, Cost of Service and Corporate Budget, PNMR Services Company, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing **Direct Testimony of Kyle T. Sanders** and it is true and correct based on my personal knowledge and belief.

DATED this 3rd day of October, 2022

/s/ Kyle T. Sanders
KYLE T. SANDERS

GCG #529843

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF	**)**	
NEW MEXICO'S APPLICATION FOR AUTHORIZATION	**)**	
TO IMPLEMENT GRID MODERNIZATION	**)**	
COMPONENTS THAT INCLUDE ADVANCED	**)**	**Case No. 22-00058-UT**
METERING INFRASTRUCTURE AND APPLICATION	**)**	
TO RECOVER THE ASSOCIATED COSTS THROUGH	**)**	
A RIDER, ISSUANCE OF RELATED ACCOUNTING	**)**	
ORDERS, AND OTHER ASSOCIATED RELIEF	**)**	

DIRECT TESTIMONY

OF

STELLA CHAN

October 3, 2022

NMPRC CASE NO. 22-00058-UT
INDEX TO THE DIRECT TESTIMONY OF
STELLA CHAN

WITNESS FOR
PUBLIC SERVICE COMPANY OF NEW MEXICO

DIRECT TESTIMONY
OF STELLA CHAN
NMPRC CASE NO. 22-00058-UT

I. INTRODUCTION AND PURPOSE

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

A. My name is Stella Chan. I am the Director of Pricing for Public Service Company of New Mexico ("PNM" or "Company"). My business address is 414 Silver Avenue SW, Albuquerque, NM 87102.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. Please see PNM Exhibit SC-1 for my educational background and professional qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION ("NMPRC" OR "COMMISSION")?

A. Yes. A list of cases in which I have filed testimony is included in PNM Exhibit SC-1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is: 1) to describe the derivation, including a discussion on allocation, and applicability of the proposed Grid Modernization Rider ("GMR"), which recovers grid modernization capital costs and expenses; 2) to support the one-time and monthly fees that customers will be charged for opting out of advanced metering infrastructure ("Opt-Out fees"); 3) to identify the bill impacts of the GMR on customers including low-income customers; and 4) to describe the benefits that the collection of interval meter data from advanced metering infrastructure ("AMI") will bring to modern rate design.

II. GRID MODERNIZATION RIDER

Q. IS PNM PROPOSING A NEW RIDER TO RECOVER GRID MODERNIZATION COSTS?

A. Yes. PNM is proposing a Grid Modernization Rider ("GMR") in accordance with NMSA 1978, § 62-8-13(C) (2021). See PNM Exhibit SC-2. PNM has not filed an advice notice at this time to implement the GMR. Once the Commission approves PNM's application in this proceeding, PNM will file an advice notice to implement the GMR.

Q. WHAT COSTS WILL BE INCLUDED FOR RECOVERY THROUGH THIS PROPOSED NEW RIDER?

A. As described by PNM witness Kyle Sanders in his testimony, nine separate projects are included in the revenue requirement calculation. The nine separate projects in the revenue requirement include: an Advanced Distribution Management System ("ADMS"), Advanced Metering, Customer Information & Analytics, Cybersecurity, Data Management and Architecture, Distribution Planning and

Engineering, Distribution Automation, Telecommunications, and Program Oversight.

Q. HOW WAS THE REVENUE REQUIREMENT USED TO DEVELOP THE CHARGES?

A. PNM recommends using the total year 1 revenue requirement for all nine projects to develop the charges in the GMR. The charge reflects the comprehensive approach being taken by PNM for grid modernization pursuant to NMSA 1978, Section 62-8-13.

Q. HOW ARE GRID MODERNIZATION COSTS ALLOCATED?

A. PNM proposes to use the last Commission-approved methodology for allocating distribution and customer costs according to the purpose, function, and benefit of the grid modernization investments. For functionalization, PNM will use the most recent allocators as filed in Case No. 16-00276-UT, which were based on an approved allocation methodology from Case No. 15-00261-UT. After PNM allocates by purpose, function, and benefit, it will then allocate to each customer class. For the customer class allocation, PNM will use the most recent class allocators as filed in Case No. 16-00276-UT, which were based on an approved allocation methodology from Case No. 15-00261-UT. In the annual review and reconciliation process, as discussed below, PNM will update the allocations to reflect any new Commission-approved methodology and allocators from a subsequent general rate case. However, in accordance with NMSA 1978, Section 62-8-13(D), PNM will not allocate any grid modernization costs that only benefit electric distribution customers to its transmission customers. PNM Exhibit SC-3 provides the functional allocators, as well as the class allocation factors that are used to develop the charges in PNM Exhibit SC-4.

Q. HOW WILL THE ALLOCATED COSTS BE RECOVERED FROM RATE SCHEDULES?

A. PNM proposes to recover the allocated costs to each customer class through a monthly GMR charge. See PNM Exhibit SC-4. In this filing, PNM is only seeking approval of the form of the GMR charge for year 1. As noted above, PNM will file an advice notice for year 1 of the GMR once the Commission approves PNM's grid modernization application. For years 2 through 6, the GMR reflected in PNM Exhibit SC-4 are estimates based on the best available information at this time. As explained in the testimony of PNM witness Sanders, the annual review and reconciliation filing for the GMR requires PNM to file annually new projected costs for the upcoming year based on the best available information.

Q. ARE THE COSTS ALLOCATED TO EACH CUSTOMER CLASS EXPECTED TO CHANGE OVER TIME?

A. The allocations to each customer class may change from year-to-year, but for the purposes of this filing, the allocations are being held constant in years 1 through 6 to project the GMR in PNM Exhibit SC-4. However, during grid modernization implementation, the expense categories will change. For example, the initial spending in years 2 and 3 of AMI implementation is more focused on the AMI system, supporting telecommunications and data infrastructure. As the grid modernization implementation continues, the expenses incurred will shift some to supporting distribution upgrades, distribution automation and other non-AMI related enhancements. As the spending shifts through grid modernization implementation, the allocations also may change to reflect the purpose, function, and benefit of the costs. Allocation changes will be addressed in PNM's annual review and reconciliation proceeding, as explained by PNM witness Sanders. Grouping costs by function and purpose, and then allocating by customer class based on Commission-approved allocators, will align costs with cost causation.

Q. WHY IS PNM PROPOSING A FIXED MONTHLY CHARGE?

A. There are various pricing structures that PNM could use to recover grid modernization costs, such as a per kWh charge, a demand charge, a monthly charge, or a combination. However, when PNM looks at pricing structures, certain criteria are considered, including that the proposed structure is easy to understand, the charge or rate is easy to administer, the charge or rate does not fluctuate greatly from month to month, and the charge or rate provides stable cost recovery. PNM proposes a fixed monthly charge because it meets those criteria. In addition, a modernized grid benefits all customers and charges should not be based upon usage but rather on connectivity to the grid.

Q. PLEASE PROVIDE THE PROPOSED GMR CHARGE BY CUSTOMER CLASS.

A. PNM Table SC-1 lists the proposed GMR charge for every customer class for year 1.

PNM Table SC-1

Line	Customer Class	GMR monthly charge ($/customer bill)
1	1 - Residential	$1.16
2	2 - Small Power	$2.87
3	3B / 3D - General Power	$18.94
4	3C / 3E - General Power Low LF	$16.82
5	4B - Large Power	$93.52
6	5B - Lg. Svc. (8 MW)	$120.70
7	10A/B - Irrigation	$15.34
8	11B - Wtr/Swg Pumping	$81.69
9	15B - Universities 115 kV	$71.81
10	30B - Manuf. (30 MW)	$404.13
11	33B - Lg. Svc. (Station Power)	$71.81
12	35B - Lg. Svc. (3 MW)	$117.80
13	36B - SSR - Renew. Energy Res.	$71.81
14	6 - Private Area Lighting*	$0.03
15	20 - Streetlighting*	$0.01

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

For additional detail for years 2 through 6 of the GMR, please see PNM Exhibit SC-4.

Q. PLEASE EXPLAIN PNM'S ANNUAL REVIEW AND RECONCILIATION FILING FOR THE GMR.

A. As described by PNM witness Sanders, PNM is presenting 6 years of grid modernization revenue requirements, but for purposes of the GMR charge to customers, PNM is only specifically forecasting the revenue requirement for the first 12-month period the GMR will be in effect. PNM witness Sanders describes the annual review and reconciliation filing process for each subsequent 12-month period for the GMR charge.

Q. WHEN WILL THE GMR TAKE EFFECT AND WHY?

A. The GMR will take effect upon Commission issuance of an order for this grid modernization application. PNM would hope for an order from the Commission in the second quarter of 2023. However, if the grid modernization application is approved during the peak summer months of June, July or August, PNM proposes that the GMR take effect by September 1, 2023.

PNM has a seasonal rate structure such that rates are higher during the summer rate period, which includes June, July, and August. In addition, customers use more electricity during the summer months typically due to hotter temperatures and air conditioning. Since the GMR is a new rider rate for a new program, PNM believes it is appropriate for the GMR to take effect outside of the peak summer months of June, July, and August. Moreover, PNM generally staggers the implementation of updated rider rates for different programs—having riders get updated in different months—and typically avoids implementing updated rider rates in the summer months. Given the foregoing, it is the Company's desire to have the effective date of the GMR be outside of the peak summer months, and in effect by no later than September 1, 2023.

III. OPT-OUT FEE

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I discuss PNM's proposed one-time and monthly Opt-Out fees. PNM witness Morgan supports the costs that will be used to derive the Opt-Out fees and has attached a workpaper, PNM Exhibit ECM-2, to show how those fees are determined. As explained by Mr. Morgan, the purpose of the Opt-Out fees is to allocate the additional costs incurred due to customers opting out of AMI. For the monthly Opt-Out fee, the primary costs are related to manually reading the meters and maintaining the infrastructure to continue manual readings. Additional one-time costs for non-standard equipment are also allocated to those customers who choose to opt-out.

Q. PLEASE EXPLAIN THE COSTS THAT PNM WILL INCUR FOR CUSTOMERS TO OPT-OUT OF AN AMI METER.

A. As explained by Mr. Morgan, PNM has divided the opt-out costs into two broad categories: ongoing costs and one-time costs. These are the expected costs that PNM will incur to support a non-standard metering and billing infrastructure for the sole purpose of supporting those customers who wish to opt-out of AMI meter technology with built-in communication capability. The standard meter for customers post-deployment will be an AMI meter that communicates interval data electronically. As such, no staff are required to obtain manual readings from AMI meters on a regular basis**.** For customers who opt-out of getting an AMI meter, their standard meter, which lacks communication capability, must be read manually each month. In addition to the costs of manual reading, there are administrative costs to track customers who have opted out of the advanced meter installation. Please see the Direct Testimony of PNM witness Morgan for additional details.

Q. HAS PNM CALCULATED THE ONE-TIME AND MONTHLY CHARGES FOR OPTING OUT OF ADVANCED METERING SERVICE?

A. Yes. PNM Exhibit ECM-2 shows the components of the up-front and monthly charges. The one-time Opt-Out fee will be dependent on whether the advanced meter exchange has occurred or not. The proposed Opt-Out fees are provided in PNM Exhibit ECM-2. As explained by Mr. Morgan, the proposed Opt-Out fees shown in PNM Exhibit ECM-2 are projected at this time. PNM will formally file advice notices for these one-time and monthly Opt-Out fees closer in time to the applicability of those charges.

IV. CUSTOMER IMPACTS OF THE GRID MODERNIZATION RIDER

Q. HAS PNM CALCULATED THE IMPACTS OF THE GMR CHARGE ON CUSTOMERS?

A. Yes. PNM has calculated the bill impact for each rate schedule at various consumption levels. Please see PNM Exhibit SC-5.

Q. HAS PNM ESTIMATED THE IMPACTS ON LOW-INCOME CUSTOMERS FOR YEAR 1 OF THE PROPOSED GMR?

A. Yes. PNM collected usage data from customers who are at or below 200% of the Federal Poverty Level ("FPL") in 11 cities and tribal communities within PNM's service territory. The month of July 2021 was selected to represent a summer month, and for winter usage, January 2022 was used. PNM Table SC-2 below lists the monthly usage.

PNM Table SC-2

Premise City	LI Avg Usage (kWh) July 2021	LI Avg Usage (kWh) Jan 2022
Albuquerque	678	602
Belen	720	758
Clayton	598	636
Cochiti Pueblo	556	675
Deming	639	634
Las Vegas	379	614
Lordsburg	726	581
Rio Rancho	848	667
Santa Fe	498	690
Santo Domingo Pueblo	628	908
Silver City	521	614

PNM Table SC-3 below shows the low-income customer monthly bill under current rates, and the bill including the GMR. The percentage increase for year 1 of the GMR is also presented in PNM Table SC-3. PNM Table SC-3 indicates that the impact for the proposed year 1 of the GMR as it relates to the customer's total bill ranges from under 1% for Rio Rancho low-income customers to 2.3% for Las Vegas low-income customers, based on a July 2021 bill. Additionally, PNM Table SC-3 shows that impacts on low-income customers for year 1 of the GMR based on a January 2022 bill would range from under 1% for Santo Domingo Pueblo to 1.5% for Lordsburg.

PNM Table SC-3

GMR – Bill Impact on Low-income Customers @ 200% FPL

Premise City	Total Bill @ current rates July 2021	Total Bill w/ GMR July 2021	Increase* ($)	Increase (%)	Total Bill @ current rates Jan 2022	Total Bill w/GMR Jan 2022	Increase* ($)	Increase (%)
	[A]	[B]	[C] = [B] - [A]	[D] = ([B]-[A]) / [A]	[E]	[F]	[G] = [F] - [E]	[H] = ([F] - [E])/[E]
Albuquerque	$99.40	$100.60	$1.20	1.2%	$83.99	$85.20	$1.20	1.4%
Belen	$106.43	$107.63	$1.20	1.1%	$107.36	$108.56	$1.20	1.1%
Clayton	$86.01	$87.21	$1.20	1.4%	$89.09	$90.29	$1.20	1.3%
Cochiti Pueblo	$78.97	$80.17	$1.20	1.5%	$94.93	$96.13	$1.20	1.3%
Deming	$92.87	$94.07	$1.20	1.3%	$88.78	$89.99	$1.20	1.4%
Las Vegas	$52.73	$53.93	$1.20	2.3%	$85.79	$86.99	$1.20	1.4%
Lordsburg	$107.43	$108.63	$1.20	1.1%	$80.85	$82.05	$1.20	1.5%
Rio Rancho	$127.87	$129.07	$1.20	0.9%	$93.73	$94.93	$1.20	1.3%
Santa Fe	$69.25	$70.46	$1.20	1.7%	$97.18	$98.38	$1.20	1.2%
Santo Domingo Pueblo	$91.03	$92.23	$1.20	1.3%	$129.95	$131.16	$1.20	0.9%
Silver City	$73.11	$74.31	$1.20	1.6%	$85.79	$86.99	$1.20	1.4%

*The increase in dollars is the monthly residential customer charge in year 1 of $1.16/bill, plus the increase in the energy efficiency charge, which is calculated as a percentage of the total bill.

While PNM understands that all bill impacts on low-income customers are an important consideration, the overall benefits of grid modernization, including flexible billing options as described by PNM witness Mario Cervantes, and enhanced reliability and resiliency, as described by PNM witness Omni Warner, balance the projected bill impact. Moreover, over time, the benefit of AMI will provide low-income customers usage data to make decisions about energy use and rate options, which could both lead to saving money on their electricity bill.

V. CUSTOMER BENEFITS OF AMI AS IT RELATES TO RATE DESIGN

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section, I will discuss customer benefits related to AMI. In particular, the discussion will be centered around potential modern rate design options that will be supported by AMI capabilities and data, offering customers ways to manage their energy usage that could not happen without AMI.

Q. WHY DOES PNM NEED A MORE MODERN RATE DESIGN?

A. PNM's current rates and pricing structures are reflective of a different time when its supply portfolio was dominated by fossil fuels. As PNM transitions to a carbon free portfolio, a more robust pricing structure and rate design are appropriate and are required to reflect the changing landscape. Moreover, customer needs and expectations, as well as technology, are also driving the need for change. Customers are seeking more choices and want to have the ability to interconnect distributed energy resources or charge electric vehicles, as reflected in the customer surveys described by PNM witness Julie Rowey and the stakeholder feedback described by PNM witness Laura Sanchez. Customers today need rate options to manage their electricity usage according to their individual needs.

Q. IS PNM PROPOSING ANY CHANGES TO CUSTOMER RATE OFFERINGS AS A PART OF THIS CASE?

A. No, but new rate options will be addressed in PNM's upcoming rate case. AMI metering is a foundational and critical technology that allows modern rate designs. These types of modern digital meters enable two-way communication, providing seamless data usage collection.

In its upcoming rate case, PNM will propose a time-of-day pilot rate. Once the efficacy of that rate is confirmed through the pilot, PNM's plan over time is to transition to default time-of-day rates for all customers. These rates require interval meter data to provide the opportunity for customers to control their bills by managing their energy consumption during specific times of the day.

Q. WHAT BENEFITS BECOME AVAILABLE TO CUSTOMERS FOR RATE DESIGN OPTIONS IF ADVANCED METERS ARE APPROVED AND INSTALLED?

A. Advanced meters play a vital role in providing customers with more modern rate designs such that they can choose options to save money by adjusting their daily and monthly usage patterns. PNM's Rate Design Strategy Mission[1] is aimed at developing an evolved rate design tailored towards transparency and stakeholder

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[1] PNM's Rate Design Strategy Mission is a stakeholder-driven process whereby PNM is getting input from stakeholders about issues that are important to building a modern rate design. PNM has conducted three stakeholder workshops for this Rate Design Strategy Mission and will conduct at least one more workshop after this filing is made.

engagement that provides customers with pricing options for existing and emerging technology as PNM moves towards a carbon free future. This will be discussed in more detail in PNM's upcoming rate case filing.

Q. PLEASE DISCUSS HOW PNM MAY BE ABLE TO USE CUSTOMER DATA FROM AMI APPLICATIONS IN DEVELOPING ADDITIONAL RATE OPTIONS?

A. Currently, PNM uses a sample of customers to estimate the usage for all customers. Having interval data for most customers will allow more detailed analysis of customer impacts from various rate designs. Furthermore, specific groups of customers, such as low-income, can be analyzed to inform future rate design proposals. With the new interval meter data, PNM will be able to see how different rate designs may impact usage patterns, with the goal to design rates that are easier for customers to adapt to, modify their consumption, and control or reduce their bills.

VI. CONCLUSION

Q. PLEASE SUMMARIZE THE GENERAL CONCLUSIONS OF YOUR TESTIMONY.

A. PNM's proposal to have the GMR be a fixed monthly charge is appropriate, in that it is easy to understand, easy to administer, the charge will not fluctuate greatly from month to month, and it provides stable cost recovery. Additionally, PNM's proposed cost-based approach to determining Opt-Out fees is equitable, in that customers who choose to opt-out of AMI will only be charged the actual costs that PNM will continue to incur as a result of their decision to opt-out. The bill impact of the GMR on all customers, and particularly, low-income customers is reasonable in light of the benefits of grid modernization. Finally, advanced meters will unlock the opportunity for PNM to study and adopt a more modern rate design with new rate options, giving customers an opportunity to save money and control their bills by adjusting their daily and monthly usage patterns.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

GCG#529875

STELLA CHAN: EDUCATIONAL AND PROFESSIONAL SUMMARY

Name: Stella Chan

Address: Public Service Company of New Mexico
Main Offices
Albuquerque, New Mexico 87158-1105

Position: Director, Pricing and Strategic Customer Marketing

Education: University of Houston, Houston, Texas
- MBA with concentration in Finance
- BBA with major in Finance

Language Skills:
Fluent in English, Mandarin Chinese and Cantonese

Employment: Public Service Company of New Mexico, Albuquerque, New Mexico:
Director, Pricing & Strategic Customer Marketing: 2013 to present

Colorado Springs Utilities, Colorado Springs, Colorado
Manager, Pricing & Forecasting, Planning and Finance Division: 2003-2013

University of Houston, Houston, Texas, New Mexico:
Adjunct Faculty – Finance Department: 2003

Independent Consultant: 2002 to 2003
- Challenger Development, L.C.
- Boyce Power System

Energy Wholesale Operations, Houston, Texas
Director, Government and Regulatory Affairs: 2001

Enron Corporation, Houston, Texas
Director, Government Affairs: 2000-2001
General Manager, Operations, SK-Enron, Seoul, South Korea: 1999-2000
Director, Regulatory Affairs, Enron International: 1997-1999
Manager, Rates and Tariffs, Enron Energy Services: 1997

El Paso Energy, Houston, Texas
Staff Analyst, Research and Competitive Analysis: 1996-1997
Consultant, Business Development: 1995-1996

Employment (Continued):

Duke Energy (formerly Texas Eastern), Houston, Texas
Project Leader, Strategic Planning: 1994-1005
Project Leader, Market Planning and Analysis: 1992-1994

El Paso Energy (formerly Tenneco Gas), Houston, Texas
Senior Analyst, Cost Allocation and Rate Design: 1990-1992
Analyst, Special Projects: 1987-1989

Community Activities (Colorado Springs, Colorado):

Board Chair, Urban Peak Colorado Springs
Treasurer, Urban Peak Colorado Spring
Board Member, CASA (Court Appointed Special Advocate), Pikes Peak Region
Steering Committee, Community Focus Fund, Colorado Springs Utilities

Testimony Filed Before the New Mexico Public Regulation Commission:

Case Number	Proceeding/Subject Matter
Un-Docketed	Advice Notice No. 478, relating to the revision of PNM Rate No. 20- Integrated System Streetlighting and Floodlighting Service, September 27, 2013
Un-Docketed	Advice Notice Nos. 480 and 65, regarding consolidation of PNM's North and South Rules, updates to service rules, and changes to Rule 15 - Line Extension Policy, November 15, 2013
14-00118-UT	Matter of PNM's Advice Notice 493, relating to modification to the qualifying criteria for service under Rate No. 5B-Large Service to Customers, April 22, 2014
14-00150-UT	Matter of PNM's Application for Approval of the City of Rio Rancho Underground Project Rider Pursuant to Advice Notice No. 495, May 25, 2014
14-00158-UT	PNM's Renewable Energy Portfolio Procurement Plan for 2015 and Proposed 2015 Rider No. 36 Rate, June 2, 2014
14-00310-UT	PNM's Application for Approval of 2014 Electric Energy Efficiency and Load Management Program Plan and Revision to Tariff Rider No. 16, October 6, 2014
14-00332-UT	Application of PNM for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 507

14-00337-UT	Application of PNM for Approval of the City of Albuquerque 2014 Underground Project Rider pursuant to Advice Notice No. 502
15-00166-UT	In the Matter of Public Service Company of New Mexico's Renewable Energy Portfolio Procurement Plan for 2016 and Proposed 2016 Rider Rate Under Rate Rider No. 36
15-00261-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. 513
16-00276-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. 533
19-00018-UT	Abandonment of San Juan Generating Station Units 1 & 4
19-00158-UT	In the Matter of Public Service Company of New Mexico's Application for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos 560 and 561
20-00121-UT	Petition for Rate Adjustment Mechanism to Remove Regulatory Disincentives
21-00031-UT	Application for Approval of Two PPA's and ESA's and Addendum to Special Service Contract

GCG#529838

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. XX

Grid Modernization Rider

APPLICABILITY: In conformance with the Grid Modernization Statute, NMSA 1978, § 62-8-13, the rider ("Grid Modernization Rider" or "Rider") will apply to all retail rate schedules of Public Service Company of New Mexico (the "Company" or "PNM").

TERRITORY: All territory served by the Company in New Mexico

DESCRIPTION: This Rider is established to recover the capital costs and expenses of Commission-approved grid modernization projects in conformance with the Grid Modernization Statute, NMSA 1978, § 62-8-13

GRID MODERNIZATION RATE: The Grid Modernization rate is a monthly charge per customer or per light that does not vary with seasons and does not vary by customer or light within the same rate class.

Customer Class	Monthly Charge
Residential Service 1A & 1B	$1.16
Small Power Service 2A & 2B	$2.87
General Power Service 3B & 3C	3B/3D: $18.94 and 3C/3E: $16.82
Large Power Service 4B	$93.52
Large Power Service for Customers >=8,000kW 5B	$120.70
Private Area Lighting Service 6	$0.03
Irrigation Service 10A & 10B	$15.34
Water & Sewage Pumping 11B	$81.69
Large Service for Public Universities 15B	$71.81
Streetlighting and Floodlighting Service 20	$0.01
Large Service, Manufacturing – Distribution Level 30B	$404.13
Large Service for Station Power 33B	$71.81
Large Power Service >=3,000kW 35B	$117.80

Advice Notice No. xxx

_/s/ Mark Fenton_____________
Mark Fenton
Executive Director, Regulatory Policy and Case Management

GCG#

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

ORIGINAL RIDER NO. XX

Grid Modernization Rider

Special Service -Renw. Energy Res. 36B	$71.81

ANNUAL REVIEW AND RECONCILIATION FILING: After the initial Rider approval, PNM will file annually the projected revenue requirement and Grid Modernization Rate with the Commission six (6) months prior to the proposed effective date of the Grid Modernization Rate. The Annual Review and Reconciliation Filing will contain two components: updated forecasted costs for the upcoming rate year based on the best available information and a true-up of actual costs incurred in the prior year to the projected revenue requirement filed in the prior year's Annual Review and Reconciliation Filing. Between Annual Review and Reconciliation Filings, PNM shall record any over-collection or under-collection of costs in a regulatory asset or regulatory liability subject to a symmetrical 4 percent carrying charge for over or under collections.

RULES AND REGULATIONS: In addition to the Grid Modernization Rate described above, all specifics of service and monthly charges for electric service under the customer's regular rate schedule apply. Where they are not inconsistent with this Rider, the Company's Rules and Regulations are a part of this Rider as if fully written herein.

Advice Notice No. xxx

/s/ Mark Fenton
Mark Fenton
Executive Director, Regulatory Policy and Case Management

Line	Revenue Requirement	Functional Allocators	Functionalization													
			PNM Retail	Production-Demand	Production-Energy-Fuel	Production-Energy-Non-Fuel	Transmission-Demand	Distribution-Demand-Subs	Distribution-Demand-Primary	Distribution-Demand-Secondary	Distribution-Customer-Services	Distribution-Customer-Meters	Distribution-Customer-Meter Reading	Distribution-Customer-Billing & Collections	Distribution-Customer-Service & Info	Distribution-Customer-Other
1	**GROSS PLANT**															
2	TOTAL DISTRIBUTION PLANT - METERS	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
3	TOTAL DISTRIBUTION PLANT - OTHER	DIST_D_SEC	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	DIST_C_OTH	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
6																
7	**ACCUMULATED DEPRECIATION**															
8	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	DIST_D_SEC	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	DIST_C_OTH	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
12																
13	**ADIT**															
14	TOTAL DISTRIBUTION ADIT - METERS	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
15	TOTAL DISTRIBUTION ADIT - OTHER	DIST_D_SEC	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	TOTAL G&I ADIT SOFTWARE	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
17	TOTAL G&I ADIT - OTHER	DIST_C_OTH	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18																
19	**O&M**															
20	TOTAL DISTRIBUTION O&M - METERS	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
21	TOTAL DISTRIBUTION O&M - OTHER	DIST_D_SEC	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
23	TOTAL GENERAL & INTANGIBLE O&M - OTHER	DIST_C_OTH	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
24	TOTAL A&G	DIST_W&S	1.00	0.00%	0.00%	0.00%	0.00%	11.72%	32.21%	18.16%	1.92%	29.78%	0.00%	0.00%	0.00%	6.21%
25																
26	**DEPRECIATION EXPENSE**															
27	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	DEPRE_DIST_METERS	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
28	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	DEPRE_DIST_OTHER	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	DEPRE_G&I_SOFT	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
30	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	DEPRE_G&I_OTHER	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
31																
32	**PROPERTY TAX**															
33	TOTAL DISTRIBUTION PROPERTY TAX - METERS	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	DIST_D_SEC	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	DIST_C_METE	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	DIST_C_OTH	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
37																
38	**TOTAL TEMPORARY DIFFERENCES**	GP_TOTAL	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	15.81%	0.00%	67.34%	0.00%	0.00%	0.00%	16.84%
39	**TOTAL REVENUE CREDITS**	GP_TOTAL	1.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	15.81%	0.00%	67.34%	0.00%	0.00%	0.00%	16.84%

PNM Exhibit SC-3: Class Allocator Summary

Line	Revenue Requirement	Class Allocators	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
				Rate Schedules														
1	GROSS PLANT																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6																		
7	ACCUMULATED DEPRECIATION																	
8	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
10	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12																		
13	ADIT																	
14	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
15	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
16	TOTAL G&I ADIT SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
17	TOTAL G&I ADIT - OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18																		
19	O&M																	
20	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
21	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
22	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
23	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Distribution-Demand-Subs	NCP_SUBS	1	46.35%	13.61%	16.22%	2.76%	10.88%	0.84%	0.49%	3.58%	0.00%	2.86%	0.00%	1.58%	0.00%	0.20%	0.64%
25	Distribution-Demand-Primary	NCP_PRI	1	48.94%	14.37%	17.12%	2.91%	11.48%	0.00%	0.52%	3.78%	0.00%	0.00%	0.00%	0.00%	0.00%	0.21%	0.67%
26	Distribution-Demand-Secondary	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
27	Distribution-Customer-Services	WTD_SERV	1	95.82%	4.18%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	Distribution-Customer-Meters	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
29	Distribution-Customer-Other	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	TOTAL A&G																	
31																		
32	DEPRECIATION EXPENSE																	
33	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
34	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
35	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
36	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37																		
38	PROPERTY TAX																	
39	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
40	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
41	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
42	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43																		
44	Distribution-Demand-Secondary	NCP_SEC	1	57.75%	16.95%	20.21%	3.44%	0.00%	0.00%	0.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.24%	0.79%
45	Distribution-Customer-Meters	WTD_METE	1	62.94%	21.25%	7.91%	2.14%	2.82%	0.02%	0.78%	2.04%	0.01%	0.01%	0.01%	0.05%	0.01%	0.00%	0.00%
46	Distribution-Customer-Other	CUSTS	1	88.99%	10.05%	0.64%	0.18%	0.04%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	TOTAL REVENUE CREDITS																	

Line	Revenue Requirement	Class Allocators	Rate Schedules															
			PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
1	**GROSS PLANT**																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	$ 2,934,096	$ 1,846,660	$ 623,500	$ 232,033	$ 62,779	$ 82,749	$ 729	$ 22,945	$ 59,783	$ 365	$ 365	$ 365	$ 1,458	$ 365	$ -	$ -
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	$ 6,020,375	$ 5,357,817	$ 604,800	$ 38,738	$ 10,603	$ 2,599	$ 23	$ 3,826	$ 1,878	$ 11	$ 11	$ 11	$ 46	$ 11	$ -	$ -
6	**TOTAL GROSS PLANT**		$ 8,954,471	$ 7,204,477	$ 1,228,301	$ 270,771	$ 73,382	$ 85,348	$ 752	$ 26,771	$ 61,661	$ 376	$ 376	$ 376	$ 1,504	$ 376	$ -	$ -
7																		
8	**ACCUMULATED DEPRECIATION**																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	$ (52,366)	$ (32,958)	$ (11,128)	$ (4,141)	$ (1,120)	$ (1,477)	$ (13)	$ (410)	$ (1,067)	$ (7)	$ (7)	$ (7)	$ (26)	$ (7)	$ -	$ -
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	$ (1,790)	$ (1,593)	$ (180)	$ (12)	$ (3)	$ (1)	$ (0)	$ (1)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ -
13	**TOTAL ACCUMULATED DEPRECIATION**		$ (54,157)	$ (34,552)	$ (11,308)	$ (4,153)	$ (1,124)	$ (1,478)	$ (13)	$ (411)	$ (1,068)	$ (7)	$ (7)	$ (7)	$ (26)	$ (7)	$ -	$ -
14																		
15	**ADIT**																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	$ (62,313)	$ (39,218)	$ (13,242)	$ (4,928)	$ (1,333)	$ (1,757)	$ (15)	$ (487)	$ (1,270)	$ (8)	$ (8)	$ (8)	$ (31)	$ (8)	$ -	$ -
19	TOTAL G&I ADIT - OTHER	CUSTS	$ (57,593)	$ (51,255)	$ (5,786)	$ (371)	$ (101)	$ (25)	$ (0)	$ (37)	$ (18)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ -
20	**TOTAL ADIT**		$ (119,906)	$ (90,473)	$ (19,027)	$ (5,298)	$ (1,435)	$ (1,782)	$ (16)	$ (524)	$ (1,288)	$ (8)	$ (8)	$ (8)	$ (31)	$ (8)	$ -	$ -
21																		
22	**TOTAL RATE BASE**		$ 8,780,408	$ 7,079,452	$ 1,197,966	$ 261,320	$ 70,824	$ 82,088	$ 723	$ 25,837	$ 59,306	$ 362	$ 362	$ 362	$ 1,446	$ 362	$ -	$ -
23	**TOTAL RATE BASE Average of 12 Months**		$ 1,274,374	$ 1,027,500	$ 173,871	$ 37,928	$ 10,279	$ 11,914	$ 105	$ 3,750	$ 8,608	$ 52	$ 52	$ 52	$ 210	$ 52	$ -	$ -
24	**RETURN ON RATE BASE**		$ 80,765	$ 65,119	$ 11,019	$ 2,404	$ 651	$ 755	$ 7	$ 238	$ 546	$ 3	$ 3	$ 3	$ 13	$ 3	$ -	$ -
25																		
26	**O&M**																	
27	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	$ 2,464,580	$ 1,551,156	$ 523,728	$ 194,903	$ 52,733	$ 69,508	$ 612	$ 19,274	$ 50,217	$ 306	$ 306	$ 306	$ 1,225	$ 306	$ -	$ -
28	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	$ 391,757	$ 226,249	$ 66,418	$ 79,166	$ 13,474	$ -	$ -	$ 2,384	$ -	$ -	$ -	$ -	$ -	$ -	$ 959	$ 3,107
29	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	$ 3,971,641	$ 2,499,670	$ 843,981	$ 314,084	$ 84,979	$ 112,011	$ 987	$ 31,059	$ 80,924	$ 493	$ 493	$ 493	$ 1,974	$ 493	$ -	$ -
30	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	$ 1,575,950	$ 1,402,512	$ 158,318	$ 10,140	$ 2,776	$ 680	$ 6	$ 1,002	$ 492	$ 3	$ 3	$ 3	$ 12	$ 3	$ -	$ -
31	Distribution-Demand-Subs	NCP_SUBS	$ 138,586	$ 64,236	$ 18,857	$ 22,476	$ 3,826	$ 15,072	$ 1,167	$ 677	$ 4,957	$ -	$ 3,968	$ -	$ 2,196	$ -	$ 272	$ 882
32	Distribution-Demand-Primary	NCP_PRI	$ 381,009	$ 186,464	$ 54,739	$ 65,245	$ 11,105	$ 43,750	$ -	$ 1,965	$ 14,389	$ -	$ -	$ -	$ -	$ -	$ 790	$ 2,561
33	Distribution-Demand-Secondary	NCP_SEC	$ 214,805	$ 124,055	$ 36,418	$ 43,407	$ 7,388	$ -	$ -	$ 1,307	$ -	$ -	$ -	$ -	$ -	$ -	$ 526	$ 1,704
34	Distribution-Customer-Services	WTD_SERV	$ 22,753	$ 21,801	$ 951	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Distribution-Customer-Meters	WTD_METE	$ 352,282	$ 221,719	$ 74,860	$ 27,859	$ 7,538	$ 9,935	$ 88	$ 2,755	$ 7,178	$ 44	$ 44	$ 44	$ 175	$ 44	$ -	$ -
36	Distribution-Customer-Other	CUSTS	$ 73,428	$ 65,347	$ 7,377	$ 472	$ 129	$ 32	$ 0	$ 47	$ 23	$ 0	$ 0	$ 0	$ 1	$ 0	$ -	$ -
37	TOTAL A&G		$ 1,182,863	$ 683,623	$ 193,203	$ 159,460	$ 29,985	$ 68,789	$ 1,255	$ 6,751	$ 26,547	$ 44	$ 4,012	$ 44	$ 2,372	$ 44	$ 1,589	$ 5,147
38	**TOTAL O&M**		$ 9,586,791	$ 6,363,209	$ 1,785,647	$ 757,753	$ 183,947	$ 250,987	$ 2,860	$ 60,470	$ 158,179	$ 847	$ 4,814	$ 847	$ 5,582	$ 847	$ 2,548	$ 8,254
39																		
40	**DEPRECIATION EXPENSE**																	
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	$ 52,366	$ 32,958	$ 11,128	$ 4,141	$ 1,120	$ 1,477	$ 13	$ 410	$ 1,067	$ 7	$ 7	$ 7	$ 26	$ 7	$ -	$ -
44	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	$ 1,790	$ 1,593	$ 180	$ 12	$ 3	$ 1	$ 0	$ 1	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -
45	**TOTAL DEPRECIATION EXPENSE**		$ 54,157	$ 34,552	$ 11,308	$ 4,153	$ 1,124	$ 1,478	$ 13	$ 411	$ 1,068	$ 7	$ 7	$ 7	$ 26	$ 7	$ -	$ -
46																		
47	**PROPERTY TAX**																	
48	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	$ 508	$ 320	$ 108	$ 40	$ 11	$ 14	$ 0	$ 4	$ 10	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -
51	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	**TOTAL PROPERTY TAX**		$ 508	$ 320	$ 108	$ 40	$ 11	$ 14	$ 0	$ 4	$ 10	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -
53																		
54	Distribution-Demand-Secondary	NCP_SEC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Distribution-Customer-Meters	WTD_METE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	Distribution-Customer-Other	CUSTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	TOTAL REVENUE CREDITS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58																		
59	Revenue Tax		$ 49,558	$ 32,961	$ 9,211	$ 3,891	$ 946	$ 1,289	$ 15	$ 311	$ 814	$ 4	$ 25	$ 4	$ 29	$ 4	$ 13	$ 42
60																		
61	Return on Rate Base		$ 80,765	$ 65,119	$ 11,019	$ 2,404	$ 651	$ 755	$ 7	$ 238	$ 546	$ 3	$ 3	$ 3	$ 13	$ 3	$ -	$ -
62	O&M		$ 9,586,791	$ 6,363,209	$ 1,785,647	$ 757,753	$ 183,947	$ 250,987	$ 2,860	$ 60,470	$ 158,179	$ 847	$ 4,814	$ 847	$ 5,582	$ 847	$ 2,548	$ 8,254
63	Depreciation Expense		$ 54,157	$ 34,552	$ 11,308	$ 4,153	$ 1,124	$ 1,478	$ 13	$ 411	$ 1,068	$ 7	$ 7	$ 7	$ 26	$ 7	$ -	$ -
64	Taxes Other Than Income		$ 50,066	$ 33,281	$ 9,319	$ 3,931	$ 956	$ 1,303	$ 15	$ 315	$ 824	$ 4	$ 25	$ 4	$ 29	$ 4	$ 13	$ 42
65	Net Allowable Federal Income Tax		$ 17,376	$ 13,918	$ 2,410	$ 543	$ 147	$ 172	$ 2	$ 54	$ 124	$ 1	$ 1	$ 1	$ 3	$ 1	$ -	$ -
66	Net Allowable State Income Tax		$ 4,882	$ 3,910	$ 677	$ 152	$ 41	$ 48	$ 0	$ 15	$ 35	$ 0	$ 0	$ 0	$ 1	$ 0	$ -	$ -
67	**TOTAL REVENUE REQUIREMENT**		$ 9,794,037	$ 6,513,990	$ 1,820,381	$ 768,936	$ 186,867	$ 254,744	$ 2,897	$ 61,502	$ 160,776	$ 862	$ 4,850	$ 862	$ 5,654	$ 862	$ 2,561	$ 8,296
68																		
69	**TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS**		$ 9,794,037	$ 6,513,990	$ 1,820,381	$ 768,936	$ 186,867	$ 254,744	$ 2,897	$ 61,502	$ 160,776	$ 862	$ 4,850	$ 862	$ 5,654	$ 862	$ 2,561	$ 8,296

PNM Exhibit SC-3: Year 2 Revenue Requirement

Line	Revenue Requirement	Class Allocators	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
									Rate Schedules									
1	**GROSS PLANT**																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	$ 33,035,902	$ 20,792,120	$ 7,020,187	$ 2,612,535	$ 706,848	$ 931,698	$ 8,209	$ 258,350	$ 673,121	$ 4,104	$ 4,104	$ 4,104	$ 16,418	$ 4,104	$ -	$ -
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	$ 11,968,345	$ 6,911,993	$ 2,029,103	$ 2,418,540	$ 411,643	$ -	$ -	$ 72,841	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,302	$ 94,923
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	$ 20,560,860	$ 12,940,584	$ 4,369,219	$ 1,625,988	$ 439,928	$ 579,869	$ 5,109	$ 160,792	$ 418,936	$ 2,554	$ 2,554	$ 2,554	$ 10,218	$ 2,554	$ -	$ -
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	$ 21,912,926	$ 19,501,351	$ 2,201,349	$ 140,997	$ 38,592	$ 9,460	$ 83	$ 13,925	$ 6,834	$ 42	$ 42	$ 42	$ 167	$ 42	$ -	$ -
6	**TOTAL GROSS PLANT**		$ 87,478,033	$ 60,146,048	$ 15,619,857	$ 6,798,060	$ 1,597,011	$ 1,521,027	$ 13,401	$ 505,908	$ 1,098,892	$ 6,701	$ 6,701	$ 6,701	$ 26,802	$ 6,701	$ 29,302	$ 94,923
7																		
8	**ACCUMULATED DEPRECIATION**																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	$ (509,927)	$ (320,938)	$ (108,360)	$ (40,326)	$ (10,911)	$ (14,381)	$ (127)	$ (3,988)	$ (10,390)	$ (63)	$ (63)	$ (63)	$ (253)	$ (63)	$ -	$ -
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	$ (219,491)	$ (126,761)	$ (37,212)	$ (44,354)	$ (7,549)	$ -	$ -	$ (1,336)	$ -	$ -	$ -	$ -	$ -	$ -	$ (537)	$ (1,741)
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	$ (1,264,213)	$ (795,670)	$ (268,647)	$ (99,976)	$ (27,050)	$ (35,654)	$ (314)	$ (9,886)	$ (25,759)	$ (157)	$ (157)	$ (157)	$ (628)	$ (157)	$ -	$ -
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	$ (374,523)	$ (333,305)	$ (37,624)	$ (2,410)	$ (660)	$ (162)	$ (1)	$ (238)	$ (117)	$ (1)	$ (1)	$ (1)	$ (3)	$ (1)	$ -	$ -
13	**TOTAL ACCUMULATED DEPRECIATION**		$ (2,368,153)	$ (1,576,673)	$ (451,844)	$ (187,066)	$ (46,169)	$ (50,197)	$ (442)	$ (15,448)	$ (36,266)	$ (221)	$ (221)	$ (221)	$ (885)	$ (221)	$ (537)	$ (1,741)
14																		
15	**ADIT**																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	$ (820,844)	$ (516,622)	$ (174,431)	$ (64,914)	$ (17,563)	$ (23,150)	$ (204)	$ (6,419)	$ (16,725)	$ (102)	$ (102)	$ (102)	$ (408)	$ (102)	$ -	$ -
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	$ (248,025)	$ (143,240)	$ (42,050)	$ (50,120)	$ (8,531)	$ -	$ -	$ (1,510)	$ -	$ -	$ -	$ -	$ -	$ -	$ (607)	$ (1,967)
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	$ (934,379)	$ (588,079)	$ (198,557)	$ (73,892)	$ (19,992)	$ (26,352)	$ (232)	$ (7,307)	$ (19,038)	$ (116)	$ (116)	$ (116)	$ (464)	$ (116)	$ -	$ -
19	TOTAL G&I ADIT - OTHER	CUSTS	$ (428,230)	$ (381,102)	$ (43,020)	$ (2,755)	$ (754)	$ (185)	$ (2)	$ (272)	$ (134)	$ (1)	$ (1)	$ (1)	$ (3)	$ (1)	$ -	$ -
20	**TOTAL ADIT**		$ (2,431,478)	$ (1,629,044)	$ (458,057)	$ (191,682)	$ (46,840)	$ (49,687)	$ (438)	$ (15,508)	$ (35,897)	$ (219)	$ (219)	$ (219)	$ (876)	$ (219)	$ (607)	$ (1,967)
21																		
22	**TOTAL RATE BASE**		$ 82,678,402	$ 56,940,331	$ 14,709,956	$ 6,419,312	$ 1,504,002	$ 1,421,143	$ 12,521	$ 474,952	$ 1,026,729	$ 6,261	$ 6,261	$ 6,261	$ 25,042	$ 6,261	$ 28,157	$ 91,216
23	**TOTAL RATE BASE Average of 12 Months**		$ 41,175,948	$ 28,357,734	$ 7,325,932	$ 3,196,981	$ 749,031	$ 707,765	$ 6,236	$ 236,538	$ 511,337	$ 3,118	$ 3,118	$ 3,118	$ 12,472	$ 3,118	$ 14,023	$ 45,428
24	**RETURN ON RATE BASE**		$ 2,609,587	$ 1,797,214	$ 464,292	$ 202,613	$ 47,471	$ 44,856	$ 395	$ 14,991	$ 32,407	$ 198	$ 198	$ 198	$ 790	$ 198	$ 889	$ 2,879
25																		
26	**O&M**																	
27	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	$ 3,129,966	$ 1,969,936	$ 665,123	$ 247,523	$ 66,970	$ 88,273	$ 778	$ 24,477	$ 63,774	$ 389	$ 389	$ 389	$ 1,555	$ 389	$ -	$ -
28	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	$ 1,217,375	$ 703,062	$ 206,393	$ 246,005	$ 41,871	$ -	$ -	$ 7,409	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,980	$ 9,655
29	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	$ 5,943,187	$ 3,740,520	$ 1,262,938	$ 469,997	$ 127,163	$ 167,613	$ 1,477	$ 46,477	$ 121,095	$ 738	$ 738	$ 738	$ 2,954	$ 738	$ -	$ -
30	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	$ 1,553,138	$ 1,382,211	$ 156,027	$ 9,994	$ 2,735	$ 670	$ 6	$ 987	$ 484	$ 3	$ 3	$ 3	$ 12	$ 3	$ -	$ -
31	Distribution-Demand-Subs	NCP_SUBS	$ 144,712	$ 67,075	$ 19,691	$ 23,470	$ 3,995	$ 15,738	$ 1,219	$ 707	$ 5,176	$ -	$ 4,143	$ -	$ 2,293	$ -	$ 284	$ 921
32	Distribution-Demand-Primary	NCP_PRI	$ 397,850	$ 194,707	$ 57,159	$ 68,129	$ 11,596	$ 45,684	$ -	$ 2,052	$ 15,025	$ -	$ -	$ -	$ -	$ -	$ 825	$ 2,674
33	Distribution-Demand-Secondary	NCP_SEC	$ 224,300	$ 129,538	$ 38,028	$ 45,326	$ 7,715	$ -	$ -	$ 1,365	$ -	$ -	$ -	$ -	$ -	$ -	$ 549	$ 1,779
34	Distribution-Customer-Services	WTD_SERV	$ 23,758	$ 22,765	$ 994	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Distribution-Customer-Meters	WTD_METE	$ 367,854	$ 231,519	$ 78,170	$ 29,090	$ 7,871	$ 10,374	$ 91	$ 2,877	$ 7,495	$ 46	$ 46	$ 46	$ 183	$ 46	$ -	$ -
36	Distribution-Customer-Other	CUSTS	$ 76,674	$ 68,236	$ 7,703	$ 493	$ 135	$ 33	$ 0	$ 49	$ 24	$ 0	$ 0	$ 0	$ 1	$ 0	$ -	$ -
37	TOTAL A&G		$ 1,235,148	$ 713,840	$ 201,743	$ 166,509	$ 31,311	$ 71,830	$ 1,311	$ 7,049	$ 27,720	$ 46	$ 4,189	$ 46	$ 2,476	$ 46	$ 1,659	$ 5,374
38	**TOTAL O&M**		$ 13,078,814	$ 8,509,570	$ 2,492,223	$ 1,140,027	$ 270,049	$ 328,386	$ 3,571	$ 86,400	$ 213,074	$ 1,176	$ 5,319	$ 1,176	$ 6,997	$ 1,176	$ 4,639	$ 15,029
39																		
40	**DEPRECIATION EXPENSE**																	
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	$ 509,927	$ 320,938	$ 108,360	$ 40,326	$ 10,911	$ 14,381	$ 127	$ 3,988	$ 10,390	$ 63	$ 63	$ 63	$ 253	$ 63	$ -	$ -
42	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	$ 219,491	$ 126,761	$ 37,212	$ 44,354	$ 7,549	$ -	$ -	$ 1,336	$ -	$ -	$ -	$ -	$ -	$ -	$ 537	$ 1,741
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	$ 1,211,846	$ 762,711	$ 257,519	$ 95,835	$ 25,929	$ 34,177	$ 301	$ 9,477	$ 24,692	$ 151	$ 151	$ 151	$ 602	$ 151	$ -	$ -
44	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	$ 372,732	$ 331,712	$ 37,444	$ 2,398	$ 656	$ 161	$ 1	$ 237	$ 116	$ 1	$ 1	$ 1	$ 3	$ 1	$ -	$ -
45	**TOTAL DEPRECIATION EXPENSE**		$ 2,313,996	$ 1,542,122	$ 440,536	$ 182,913	$ 45,045	$ 48,719	$ 429	$ 15,037	$ 35,198	$ 215	$ 215	$ 215	$ 858	$ 215	$ 537	$ 1,741
46																		
47	**PROPERTY TAX**																	
48	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	$ 278	$ 175	$ 59	$ 22	$ 6	$ 8	$ 0	$ 2	$ 6	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -
49	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	$ 87,768	$ 50,688	$ 14,880	$ 17,736	$ 3,019	$ -	$ -	$ 534	$ -	$ -	$ -	$ -	$ -	$ -	$ 215	$ 696
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	$ 42,403	$ 26,688	$ 9,011	$ 3,353	$ 907	$ 1,196	$ 11	$ 332	$ 864	$ 5	$ 5	$ 5	$ 21	$ 5	$ -	$ -
51	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	$ 46,871	$ 41,713	$ 4,709	$ 302	$ 83	$ 20	$ 0	$ 30	$ 15	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -
52	**TOTAL PROPERTY TAX**		$ 177,320	$ 119,264	$ 28,659	$ 21,413	$ 4,014	$ 1,224	$ 11	$ 898	$ 884	$ 5	$ 5	$ 5	$ 22	$ 5	$ 215	$ 696
53																		
54	Distribution-Demand-Secondary	NCP_SEC	$ (893)	$ (516)	$ (151)	$ (180)	$ (31)	$ -	$ -	$ (5)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2)	$ (7)
55	Distribution-Customer-Meters	WTD_METE	$ (3,999)	$ (2,517)	$ (850)	$ (316)	$ (86)	$ (113)	$ (1)	$ (31)	$ (81)	$ (0)	$ (0)	$ (0)	$ (2)	$ (0)	$ -	$ -
56	Distribution-Customer-Other	CUSTS	$ (1,635)	$ (1,455)	$ (164)	$ (11)	$ (3)	$ (1)	$ (0)	$ (1)	$ (1)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ -
57	TOTAL REVENUE CREDITS		$ (6,527)	$ (4,488)	$ (1,166)	$ (507)	$ (119)	$ (113)	$ (1)	$ (38)	$ (82)	$ (0)	$ (0)	$ (0)	$ (2)	$ (0)	$ (2)	$ (7)
58																		
59	Revenue Tax		$ 96,118	$ 63,385	$ 18,075	$ 8,152	$ 1,931	$ 2,216	$ 23	$ 618	$ 1,478	$ 8	$ 29	$ 8	$ 45	$ 8	$ 33	$ 107
60																		
61	Return on Rate Base		$ 2,609,587	$ 1,797,214	$ 464,292	$ 202,613	$ 47,471	$ 44,856	$ 395	$ 14,991	$ 32,407	$ 198	$ 198	$ 198	$ 790	$ 198	$ 889	$ 2,879
62	O&M		$ 13,078,814	$ 8,509,570	$ 2,492,223	$ 1,140,027	$ 270,049	$ 328,386	$ 3,571	$ 86,400	$ 213,074	$ 1,176	$ 5,319	$ 1,176	$ 6,997	$ 1,176	$ 4,639	$ 15,029
63	Depreciation Expense		$ 2,313,996	$ 1,542,122	$ 440,536	$ 182,913	$ 45,045	$ 48,719	$ 429	$ 15,037	$ 35,198	$ 215	$ 215	$ 215	$ 858	$ 215	$ 537	$ 1,741
64	Taxes Other Than Income		$ 273,439	$ 182,649	$ 46,734	$ 29,565	$ 5,946	$ 3,440	$ 34	$ 1,516	$ 2,362	$ 14	$ 35	$ 14	$ 67	$ 14	$ 248	$ 804
65	Net Allowable Federal Income Tax		$ 567,080	$ 390,029	$ 101,183	$ 44,062	$ 10,345	$ 9,837	$ 87	$ 3,275	$ 7,107	$ 43	$ 43	$ 43	$ 173	$ 43	$ 191	$ 617
66	Net Allowable State Income Tax		$ 159,323	$ 109,580	$ 28,428	$ 12,379	$ 2,907	$ 2,764	$ 24	$ 920	$ 1,997	$ 12	$ 12	$ 12	$ 49	$ 12	$ 54	$ 173
67	**TOTAL REVENUE REQUIREMENT**		$ 19,002,238	$ 12,531,162	$ 3,573,395	$ 1,611,560	$ 381,763	$ 438,002	$ 4,540	$ 122,139	$ 292,145	$ 1,658	$ 5,822	$ 1,658	$ 8,935	$ 1,658	$ 6,558	$ 21,244
68																		
69	**TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS**		$ 18,995,710	$ 12,526,674	$ 3,572,230	$ 1,611,053	$ 381,644	$ 437,889	$ 4,539	$ 122,101	$ 292,063	$ 1,657	$ 5,821	$ 1,657	$ 8,933	$ 1,657	$ 6,556	$ 21,237

PNM Exhibit SC-3: Year 3 Revenue Requirement

Line	Revenue Requirement	Class Allocator	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
			Rate Schedules															
1	**GROSS PLANT**																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	94,361,455	59,389,167	20,051,973	7,462,264	2,018,991	2,661,237	23,447	737,932	1,922,655	11,724	11,724	11,724	46,894	11,724	-	-
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	28,119,194	16,239,477	4,767,304	5,682,272	967,140	-	-	171,137	-	-	-	-	-	-	68,844	223,019
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	25,378,934	15,972,981	5,393,068	2,007,009	543,017	715,751	6,306	198,470	517,107	3,153	3,153	3,153	12,612	3,153	-	-
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	29,947,631	26,651,817	3,008,507	192,696	52,743	12,928	114	19,031	9,340	57	57	57	228	57	-	-
6	**TOTAL GROSS PLANT**		177,807,213	118,253,441	33,220,852	15,344,240	3,581,891	3,389,916	29,867	1,126,571	2,449,102	14,934	14,934	14,934	59,734	14,934	68,844	223,019
7																		
8	**ACCUMULATED DEPRECIATION**																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	(3,694,861)	(2,325,470)	(785,164)	(292,196)	(79,057)	(104,205)	(918)	(28,895)	(75,284)	(459)	(459)	(459)	(1,836)	(459)	-	-
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	(770,872)	(445,196)	(130,693)	(155,776)	(26,514)	-	-	(4,692)	-	-	-	-	-	-	(1,887)	(6,114)
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	(3,561,202)	(2,241,348)	(756,762)	(281,626)	(76,197)	(100,435)	(885)	(27,850)	(72,561)	(442)	(442)	(442)	(1,770)	(442)	-	-
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	(1,897,156)	(1,688,369)	(190,586)	(12,207)	(3,341)	(819)	(7)	(1,206)	(592)	(4)	(4)	(4)	(14)	(4)	-	-
13	**TOTAL ACCUMULATED DEPRECIATION**		(9,924,091)	(6,700,383)	(1,863,205)	(741,805)	(185,108)	(205,459)	(1,810)	(62,642)	(148,437)	(905)	(905)	(905)	(3,620)	(905)	(1,887)	(6,114)
14																		
15	**ADIT**																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	(3,377,395)	(2,125,663)	(717,702)	(267,090)	(72,264)	(95,251)	(839)	(26,412)	(68,816)	(420)	(420)	(420)	(1,678)	(420)	-	-
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	(559,675)	(323,225)	(94,887)	(113,098)	(19,250)	-	-	(3,406)	-	-	-	-	-	-	(1,370)	(4,439)
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	(2,530,282)	(1,592,508)	(537,689)	(200,099)	(54,139)	(71,360)	(629)	(19,787)	(51,556)	(314)	(314)	(314)	(1,257)	(314)	-	-
19	TOTAL G&I ADIT - OTHER	CUSTS	(1,237,069)	(1,100,927)	(124,275)	(7,960)	(2,179)	(534)	(5)	(786)	(386)	(2)	(2)	(2)	(9)	(2)	-	-
20	**TOTAL ADIT**		(7,704,421)	(5,142,322)	(1,474,553)	(588,247)	(147,831)	(167,146)	(1,473)	(50,392)	(120,757)	(736)	(736)	(736)	(2,945)	(736)	(1,370)	(4,439)
21																		
22	**TOTAL RATE BASE**		160,178,701	106,410,736	29,883,094	14,014,188	3,248,952	3,017,312	26,584	1,013,538	2,179,908	13,292	13,292	13,292	53,168	13,292	65,586	212,466
23	**RETURN ON RATE BASE**		10,151,565	6,743,939	1,893,886	888,170	205,907	191,227	1,685	64,234	138,155	842	842	842	3,370	842	4,157	13,465
24																		
25	**O&M**																	
26	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	1,483,291	933,553	315,202	117,301	31,737	41,833	369	11,600	30,223	184	184	184	737	184	-	-
27	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	1,364,084	787,790	231,266	275,651	46,917	-	-	8,302	-	-	-	-	-	-	3,340	10,819
28	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	7,469,678	4,701,262	1,587,320	590,715	159,824	210,664	1,856	58,415	152,198	928	928	928	3,712	928	-	-
29	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	1,206,106	1,073,371	121,164	7,761	2,124	521	5	766	376	2	2	2	9	2	-	-
30	Distribution-Demand-Subs	NCP_SUBS	151,114	70,042	20,562	24,508	4,171	16,434	1,273	738	5,405	-	4,326	-	2,394	-	297	962
31	Distribution-Demand-Primary	NCP_PRI	415,450	203,320	59,687	71,143	12,109	47,705	-	2,143	15,690	-	-	-	-	-	862	2,792
32	Distribution-Demand-Secondary	NCP_SEC	234,222	135,269	39,710	47,331	8,056	-	-	1,426	-	-	-	-	-	-	573	1,858
33	Distribution-Customer-Services	WTD_SERV	24,809	23,772	1,037	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Distribution-Customer-Meters	WTD_METE	384,126	241,761	81,627	30,377	8,219	10,833	95	3,004	7,827	48	48	48	191	48	-	-
35	Distribution-Customer-Other	CUSTS	80,066	71,254	8,043	515	141	35	0	51	25	0	0	0	1	0	-	-
36	TOTAL A&G		1,289,787	745,418	210,667	173,874	32,696	75,007	1,369	7,361	28,947	48	4,374	48	2,586	48	1,732	5,612
37	**TOTAL O&M**		12,812,945	8,241,394	2,465,618	1,165,302	273,298	328,025	3,598	86,444	211,744	1,162	5,489	1,162	7,044	1,162	5,072	16,431
38																		
39	**DEPRECIATION EXPENSE**																	
40	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	3,184,934	2,004,532	676,804	251,870	68,146	89,823	791	24,907	64,894	396	396	396	1,583	396	-	-
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	551,382	318,435	93,481	111,422	18,964	-	-	3,356	-	-	-	-	-	-	1,350	4,373
42	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	2,296,990	1,445,678	488,114	181,650	49,147	64,781	571	17,963	46,802	285	285	285	1,142	285	-	-
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	1,522,634	1,355,064	152,962	9,797	2,682	657	6	968	475	3	3	3	12	3	-	-
44	**TOTAL DEPRECIATION EXPENSE**		7,555,939	5,123,710	1,411,361	554,739	138,939	155,262	1,368	47,194	112,171	684	684	684	2,736	684	1,350	4,373
45																		
46	**PROPERTY TAX**																	
47	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	357,786	225,183	76,030	28,294	7,655	10,090	89	2,798	7,290	44	44	44	178	44	-	-
48	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	129,237	74,638	21,911	26,116	4,445	-	-	787	-	-	-	-	-	-	316	1,025
49	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	212,263	133,594	45,106	16,786	4,542	5,986	53	1,660	4,325	26	26	26	105	26	-	-
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	236,922	210,849	23,801	1,524	417	102	1	151	74	0	0	0	2	0	-	-
51	TOTAL PROPERTY TAX		936,209	644,263	166,848	72,721	17,059	16,179	143	5,395	11,689	71	71	71	285	71	316	1,025
52																		
53	Distribution-Demand-Secondary	NCP_SEC	(2,146)	(1,239)	(364)	(434)	(74)	-	-	(13)	-	-	-	-	-	-	(5)	(17)
54	Distribution-Customer-Meters	WTD_METE	(9,137)	(5,751)	(1,942)	(723)	(196)	(258)	(2)	(71)	(186)	(1)	(1)	(1)	(5)	(1)	-	-
55	Distribution-Customer-Other	CUSTS	(2,285)	(2,034)	(230)	(15)	(4)	(1)	(0)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	-	-
56	TOTAL REVENUE CREDITS		(13,568)	(9,024)	(2,535)	(1,171)	(273)	(259)	(2)	(86)	(187)	(1)	(1)	(1)	(5)	(1)	(5)	(17)
57																		
58	Revenue Tax		174,188	114,991	32,848	14,871	3,518	3,781	37	1,124	2,603	15	37	15	73	15	61	198
59																		
60	Return on Rate Base		10,151,565	6,743,939	1,893,886	888,170	205,907	191,227	1,685	64,234	138,155	842	842	842	3,370	842	4,157	13,465
61	O&M		12,812,945	8,241,394	2,465,618	1,165,302	273,298	328,025	3,598	86,444	211,744	1,162	5,489	1,162	7,044	1,162	5,072	16,431
62	Depreciation Expense		7,555,939	5,123,710	1,411,361	554,739	138,939	155,262	1,368	47,194	112,171	684	684	684	2,736	684	1,350	4,373
63	Taxes Other Than Income		1,110,397	759,254	199,696	87,592	20,577	19,960	179	6,519	14,292	86	108	86	358	86	378	1,223
64	Net Allowable Federal Income Tax		2,191,501	1,456,913	408,866	190,670	44,307	41,411	365	13,861	29,918	182	182	182	730	182	880	2,850
65	Net Allowable State Income Tax		615,708	409,324	114,872	53,569	12,448	11,635	103	3,894	8,406	51	51	51	205	51	247	801
66	**TOTAL REVENUE REQUIREMENT**		34,438,054	22,734,534	6,494,299	2,940,043	695,477	747,519	7,297	222,146	514,686	3,009	7,357	3,009	14,443	3,009	12,083	39,143
67																		
68	**TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS**		34,424,486	22,725,510	6,491,764	2,938,872	695,203	747,261	7,295	222,060	514,499	3,008	7,356	3,008	14,438	3,008	12,078	39,126

PNM Exhibit SC-3: Year 4 Revenue Requirement

Line	Revenue Requirement	Class Allocator	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
										Rate Schedules								
1	GROSS PLANT																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	150,169,589	94,513,663	31,911,299	11,875,665	3,213,082	4,235,170	37,314	1,174,367	3,059,770	18,657	18,657	18,657	74,629	18,657	-	-
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	44,739,662	25,838,177	7,585,125	9,040,903	1,538,790	-	-	272,292	-	-	-	-	-	-	109,536	354,840
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	41,711,011	26,252,056	8,863,662	3,298,577	892,464	1,176,358	10,364	326,192	849,880	5,182	5,182	5,182	20,729	5,182	-	-
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	38,018,470	33,834,438	3,819,294	244,627	66,957	16,412	145	24,160	11,857	72	72	72	289	72	-	-
6	TOTAL GROSS PLANT		274,638,732	180,438,335	52,179,380	24,459,773	5,711,293	5,427,941	47,823	1,797,011	3,921,508	23,912	23,912	23,912	95,647	23,912	109,536	354,840
7																		
8	ACCUMULATED DEPRECIATION																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	(9,808,137)	(6,173,040)	(2,084,246)	(775,644)	(209,858)	(276,615)	(2,437)	(76,702)	(199,845)	(1,219)	(1,219)	(1,219)	(4,874)	(1,219)	-	-
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	(1,773,005)	(1,023,951)	(300,594)	(358,285)	(60,981)	-	-	(10,791)	-	-	-	-	-	-	(4,341)	(14,062)
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	(6,915,700)	(4,352,600)	(1,469,598)	(546,905)	(147,971)	(195,041)	(1,718)	(54,083)	(140,910)	(859)	(859)	(859)	(3,437)	(859)	-	-
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	(3,892,651)	(3,464,254)	(391,051)	(25,047)	(6,856)	(1,680)	(15)	(2,474)	(1,214)	(7)	(7)	(7)	(30)	(7)	-	-
13	TOTAL ACCUMULATED DEPRECIATION		(22,389,492)	(15,013,845)	(4,245,490)	(1,705,882)	(425,666)	(473,336)	(4,170)	(144,049)	(341,969)	(2,085)	(2,085)	(2,085)	(8,341)	(2,085)	(4,341)	(14,062)
14																		
15	ADIT																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	(7,538,637)	(4,744,664)	(1,601,974)	(596,168)	(161,299)	(212,609)	(1,873)	(58,954)	(153,603)	(937)	(937)	(937)	(3,746)	(937)	-	-
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	(1,045,646)	(603,884)	(177,278)	(211,302)	(35,964)	-	-	(6,364)	-	-	-	-	-	-	(2,560)	(8,293)
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	(5,048,564)	(3,177,463)	(1,072,829)	(399,249)	(108,021)	(142,383)	(1,254)	(39,481)	(102,867)	(627)	(627)	(627)	(2,509)	(627)	-	-
19	TOTAL G&I ADIT - OTHER	CUSTS	(2,108,243)	(1,876,225)	(211,792)	(13,565)	(3,713)	(910)	(8)	(1,340)	(658)	(4)	(4)	(4)	(16)	(4)	-	-
20	TOTAL ADIT		(15,741,090)	(10,402,236)	(3,063,872)	(1,220,285)	(308,997)	(355,902)	(3,136)	(106,139)	(257,127)	(1,568)	(1,568)	(1,568)	(6,271)	(1,568)	(2,560)	(8,293)
21																		
22	TOTAL RATE BASE		236,508,151	155,022,254	44,870,019	21,533,607	4,976,629	4,598,703	40,517	1,546,823	3,322,411	20,259	20,259	20,259	81,034	20,259	102,635	332,484
23	RETURN ON RATE BASE		14,989,058	9,824,767	2,843,705	1,364,725	315,401	291,450	2,568	98,032	210,563	1,284	1,284	1,284	5,136	1,284	6,505	21,072
24																		
25	O&M																	
26	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	(309,643)	(194,883)	(65,800)	(24,487)	(6,625)	(8,733)	(77)	(2,421)	(6,309)	(38)	(38)	(38)	(154)	(38)	-	-
27	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	1,540,661	889,767	261,202	311,334	52,990	-	-	9,377	-	-	-	-	-	-	3,772	12,219
28	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	7,885,648	4,963,066	1,675,714	623,610	168,724	222,396	1,959	61,668	160,674	980	980	980	3,919	980	-	-
29	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	1,348,217	1,199,842	135,440	8,675	2,374	582	5	857	420	3	3	3	10	3	-	-
30	Distribution-Demand-Subs	NCP_SUBS	157,803	73,143	21,472	25,593	4,356	17,162	1,329	771	5,644	-	4,518	-	2,500	-	310	1,004
31	Distribution-Demand-Primary	NCP_PRI	433,841	212,320	62,329	74,292	12,645	49,817	-	2,238	16,384	-	-	-	-	-	900	2,916
32	Distribution-Demand-Secondary	NCP_SEC	244,591	141,257	41,468	49,426	8,413	-	-	1,489	-	-	-	-	-	-	599	1,940
33	Distribution-Customer-Services	WTD_SERV	25,908	24,824	1,083	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Distribution-Customer-Meters	WTD_METE	401,131	252,463	85,241	31,722	8,583	11,313	100	3,137	8,173	50	50	50	199	50	-	-
35	Distribution-Customer-Other	CUSTS	83,610	74,409	8,399	538	147	36	0	53	26	0	0	0	1	0	-	-
36	TOTAL A&G		1,346,884	778,417	219,993	181,572	34,143	78,328	1,429	7,687	30,228	50	4,568	50	2,700	50	1,809	5,860
37	TOTAL O&M		11,811,767	7,636,208	2,226,550	1,100,704	251,607	292,573	3,317	77,167	185,013	994	5,512	994	6,476	994	5,581	18,080
38																		
39	DEPRECIATION EXPENSE																	
40	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	6,113,276	3,847,571	1,299,082	483,448	130,802	172,410	1,519	47,807	124,561	760	760	760	3,038	760	-	-
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	1,002,133	578,755	169,901	202,509	34,468	-	-	6,099	-	-	-	-	-	-	2,454	7,948
42	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	3,354,497	2,111,252	712,837	265,279	71,774	94,605	834	26,233	68,349	417	417	417	1,667	417	-	-
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	1,995,495	1,775,885	200,465	12,840	3,514	861	8	1,268	622	4	4	4	15	4	-	-
44	TOTAL DEPRECIATION EXPESE		12,465,401	8,313,462	2,382,284	964,076	240,558	267,877	2,360	81,408	193,532	1,180	1,180	1,180	4,720	1,180	2,454	7,948
45																		
46	PROPERTY TAX																	
47	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	997,333	627,701	211,935	78,871	21,339	28,127	248	7,799	20,321	124	124	124	496	124	-	-
48	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	300,832	173,737	51,003	60,791	10,347	-	-	1,831	-	-	-	-	-	-	737	2,386
49	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	239,995	151,048	50,999	18,979	5,135	6,768	60	1,877	4,890	30	30	30	119	30	-	-
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	308,555	274,598	30,997	1,985	543	133	1	196	96	1	1	1	2	1	-	-
51	TOTAL PROPERTY TAX		1,846,714	1,227,084	344,934	160,627	37,365	35,029	309	11,703	25,307	154	154	154	617	154	737	2,386
52																		
53	Distribution-Demand-Secondary	NCP_SEC	(2,001)	(1,155)	(339)	(404)	(69)	-	-	(12)	-	-	-	-	-	-	(5)	(16)
54	Distribution-Customer-Meters	WTD_METE	(8,581)	(5,400)	(1,823)	(679)	(184)	(242)	(2)	(67)	(175)	(1)	(1)	(1)	(4)	(1)	-	-
55	Distribution-Customer-Other	CUSTS	(1,700)	(1,513)	(171)	(11)	(3)	(1)	(0)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	-	-
56	TOTAL REVENUE CREDITS		(12,281)	(8,069)	(2,333)	(1,094)	(255)	(243)	(2)	(80)	(175)	(1)	(1)	(1)	(4)	(1)	(5)	(16)
57																		
58	Revenue Tax		230,192	151,164	43,661	20,169	4,740	4,923	47	1,503	3,422	20	43	20	93	20	87	281
59																		
60	Return on Rate Base		14,989,058	9,824,767	2,843,705	1,364,725	315,401	291,450	2,568	98,032	210,563	1,284	1,284	1,284	5,136	1,284	6,505	21,072
61	O&M		11,811,767	7,636,208	2,226,550	1,100,704	251,607	292,573	3,317	77,167	185,013	994	5,512	994	6,476	994	5,581	18,080
62	Depreciation Expense		12,465,401	8,313,462	2,382,284	964,076	240,558	267,877	2,360	81,408	193,532	1,180	1,180	1,180	4,720	1,180	2,454	7,948
63	Taxes Other Than Income		2,076,907	1,378,248	388,595	180,796	42,104	39,952	356	13,206	28,730	174	197	174	711	174	823	2,667
64	Net Allowable Federal Income Tax		3,248,936	2,130,989	616,558	294,096	68,146	63,429	559	21,248	45,825	279	279	279	1,118	279	1,380	4,471
65	Net Allowable State Income Tax		912,797	598,707	173,224	82,627	19,146	17,820	157	5,970	12,875	79	79	79	314	79	388	1,256
66	TOTAL REVENUE REQUIREMENT		45,504,866	29,882,382	8,630,915	3,987,023	936,963	973,100	9,316	297,030	676,538	3,990	8,531	3,990	18,474	3,990	17,130	55,494
67																		
68	TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS		45,492,585	29,874,313	8,628,582	3,985,929	936,707	972,857	9,314	296,950	676,362	3,989	8,530	3,989	18,470	3,989	17,125	55,478

Line	Revenue Requirement	Class Allocator	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
								Rate Schedules										
1	**GROSS PLANT**																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	$ 151,892,128	$ 95,597,795	$ 32,277,342	$ 12,011,887	$ 3,249,938	$ 4,283,750	$ 37,742	$ 1,187,838	$ 3,094,868	$ 18,871	$ 18,871	$ 18,871	$ 75,485	$ 18,871	$ -	$ -
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	$ 62,401,128	$ 36,038,077	$ 10,579,435	$ 12,609,898	$ 2,146,244	$ -	$ -	$ 379,782	$ -	$ -	$ -	$ -	$ -	$ -	$ 152,776	$ 494,917
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	$ 41,928,153	$ 26,388,721	$ 8,909,805	$ 3,315,749	$ 897,110	$ 1,182,482	$ 10,418	$ 327,890	$ 854,304	$ 5,209	$ 5,209	$ 5,209	$ 20,837	$ 5,209	$ -	$ -
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	$ 46,345,017	$ 41,244,627	$ 4,655,770	$ 298,204	$ 81,621	$ 20,007	$ 176	$ 29,452	$ 14,454	$ 88	$ 88	$ 88	$ 353	$ 88	$ -	$ -
6	**TOTAL GROSS PLANT**		$ 302,566,427	$ 199,269,220	$ 56,422,352	$ 28,235,738	$ 6,374,913	$ 5,486,239	$ 48,337	$ 1,924,962	$ 3,963,626	$ 24,168	$ 24,168	$ 24,168	$ 96,674	$ 24,168	$ 152,776	$ 494,917
7																		
8	**ACCUMULATED DEPRECIATION**																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	$ (17,359,680)	$ (10,925,827)	$ (3,688,962)	$ (1,372,833)	$ (371,434)	$ (489,588)	$ (4,314)	$ (135,757)	$ (353,711)	$ (2,157)	$ (2,157)	$ (2,157)	$ (8,627)	$ (2,157)	$ -	$ -
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	$ (3,246,666)	$ (1,875,024)	$ (550,437)	$ (656,080)	$ (111,667)	$ -	$ -	$ (19,760)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,949)	$ (25,750)
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	$ (11,097,658)	$ (6,984,639)	$ (2,358,272)	$ (877,622)	$ (237,449)	$ (312,983)	$ (2,758)	$ (86,787)	$ (226,120)	$ (1,379)	$ (1,379)	$ (1,379)	$ (5,515)	$ (1,379)	$ -	$ -
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	$ (6,369,575)	$ (5,668,587)	$ (639,881)	$ (40,985)	$ (11,218)	$ (2,750)	$ (24)	$ (4,048)	$ (1,987)	$ (12)	$ (12)	$ (12)	$ (48)	$ (12)	$ -	$ -
13	**TOTAL ACCUMULATED DEPRECIATION**		$ (38,073,579)	$ (25,454,076)	$ (7,237,551)	$ (2,947,519)	$ (731,768)	$ (805,320)	$ (7,095)	$ (246,352)	$ (581,817)	$ (3,548)	$ (3,548)	$ (3,548)	$ (14,191)	$ (3,548)	$ (7,949)	$ (25,750)
14																		
15	**ADIT**																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	$ (11,468,251)	$ (7,217,883)	$ (2,437,023)	$ (906,929)	$ (245,379)	$ (323,434)	$ (2,850)	$ (89,685)	$ (233,671)	$ (1,425)	$ (1,425)	$ (1,425)	$ (5,699)	$ (1,425)	$ -	$ -
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	$ (1,696,674)	$ (979,868)	$ (287,653)	$ (342,861)	$ (58,356)	$ -	$ -	$ (10,326)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,154)	$ (13,457)
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	$ (5,824,780)	$ (3,665,997)	$ (1,237,776)	$ (460,633)	$ (124,629)	$ (164,274)	$ (1,447)	$ (45,551)	$ (118,682)	$ (724)	$ (724)	$ (724)	$ (2,895)	$ (724)	$ -	$ -
19	TOTAL G&I ADIT - OTHER	CUSTS	$ (3,012,560)	$ (2,681,020)	$ (302,639)	$ (19,384)	$ (5,306)	$ (1,301)	$ (11)	$ (1,914)	$ (940)	$ (6)	$ (6)	$ (6)	$ (23)	$ (6)	$ -	$ -
20	**TOTAL ADIT**		$ (22,002,265)	$ (14,544,768)	$ (4,265,090)	$ (1,729,807)	$ (433,669)	$ (489,009)	$ (4,308)	$ (147,477)	$ (353,293)	$ (2,154)	$ (2,154)	$ (2,154)	$ (8,617)	$ (2,154)	$ (4,154)	$ (13,457)
21																		
22	**TOTAL RATE BASE**		$ 242,490,583	$ 159,270,376	$ 44,919,710	$ 23,558,412	$ 5,209,476	$ 4,191,910	$ 36,933	$ 1,531,133	$ 3,028,517	$ 18,467	$ 18,467	$ 18,467	$ 73,866	$ 18,467	$ 140,673	$ 455,710
23	**RETURN ON RATE BASE**		$ 15,368,203	$ 10,093,998	$ 2,846,854	$ 1,493,050	$ 330,158	$ 265,669	$ 2,341	$ 97,038	$ 191,937	$ 1,170	$ 1,170	$ 1,170	$ 4,681	$ 1,170	$ 8,915	$ 28,881
24																		
25	**O&M**																	
26	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	$ (2,181,698)	$ (1,373,116)	$ (463,615)	$ (172,532)	$ (46,680)	$ (61,530)	$ (542)	$ (17,061)	$ (44,453)	$ (271)	$ (271)	$ (271)	$ (1,084)	$ (271)	$ -	$ -
27	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	$ 1,755,824	$ 1,014,028	$ 297,681	$ 354,813	$ 60,390	$ -	$ -	$ 10,686	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,299	$ 13,926
28	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	$ 9,042,234	$ 5,690,997	$ 1,921,490	$ 715,075	$ 193,471	$ 255,014	$ 2,247	$ 70,713	$ 184,239	$ 1,123	$ 1,123	$ 1,123	$ 4,494	$ 1,123	$ -	$ -
29	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	$ 1,315,303	$ 1,170,551	$ 132,134	$ 8,463	$ 2,316	$ 568	$ 5	$ 836	$ 410	$ 3	$ 3	$ 3	$ 10	$ 3	$ -	$ -
30	Distribution-Demand-Subs	NCP_SUBS	$ 164,794	$ 76,383	$ 22,423	$ 26,727	$ 4,549	$ 17,922	$ 1,388	$ 805	$ 5,894	$ -	$ 4,718	$ -	$ 2,611	$ -	$ 324	$ 1,049
31	Distribution-Demand-Primary	NCP_PRI	$ 453,060	$ 221,726	$ 65,091	$ 77,583	$ 13,205	$ 52,024	$ -	$ 2,337	$ 17,110	$ -	$ -	$ -	$ -	$ -	$ 940	$ 3,045
32	Distribution-Demand-Secondary	NCP_SEC	$ 255,426	$ 147,514	$ 43,305	$ 51,616	$ 8,785	$ -	$ -	$ 1,555	$ -	$ -	$ -	$ -	$ -	$ -	$ 625	$ 2,026
33	Distribution-Customer-Services	WTD_SERV	$ 27,055	$ 25,924	$ 1,131	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution-Customer-Meters	WTD_METE	$ 418,901	$ 263,647	$ 89,017	$ 33,127	$ 8,963	$ 11,814	$ 104	$ 3,276	$ 8,535	$ 52	$ 52	$ 52	$ 208	$ 52	$ -	$ -
35	Distribution-Customer-Other	CUSTS	$ 87,314	$ 77,705	$ 8,771	$ 562	$ 154	$ 38	$ 0	$ 55	$ 27	$ 0	$ 0	$ 0	$ 1	$ 0	$ -	$ -
36	TOTAL A&G		$ 1,406,550	$ 812,900	$ 229,739	$ 189,615	$ 35,656	$ 81,797	$ 1,492	$ 8,028	$ 31,567	$ 52	$ 4,770	$ 52	$ 2,820	$ 52	$ 1,889	$ 6,120
37	**TOTAL O&M**		$ 11,338,213	$ 7,315,360	$ 2,117,429	$ 1,095,435	$ 245,153	$ 275,850	$ 3,202	$ 73,201	$ 171,764	$ 907	$ 5,625	$ 907	$ 6,240	$ 907	$ 6,188	$ 20,046
38																		
39	**DEPRECIATION EXPENSE**																	
40	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	$ 7,551,543	$ 4,752,786	$ 1,604,716	$ 597,189	$ 161,576	$ 212,973	$ 1,876	$ 59,055	$ 153,866	$ 938	$ 938	$ 938	$ 3,753	$ 938	$ -	$ -
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	$ 1,473,662	$ 851,073	$ 249,843	$ 297,795	$ 50,686	$ -	$ -	$ 8,969	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,608	$ 11,688
42	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	$ 4,181,958	$ 2,632,039	$ 888,673	$ 330,716	$ 89,479	$ 117,942	$ 1,039	$ 32,704	$ 85,209	$ 520	$ 520	$ 520	$ 2,078	$ 520	$ -	$ -
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	$ 2,476,924	$ 2,204,332	$ 248,829	$ 15,938	$ 4,362	$ 1,069	$ 9	$ 1,574	$ 773	$ 5	$ 5	$ 5	$ 19	$ 5	$ -	$ -
44	**TOTAL DEPRECIATION EXPENSE**		$ 15,684,087	$ 10,440,231	$ 2,992,062	$ 1,241,637	$ 306,102	$ 331,984	$ 2,925	$ 102,302	$ 239,848	$ 1,462	$ 1,462	$ 1,462	$ 5,850	$ 1,462	$ 3,608	$ 11,688
45																		
46	**PROPERTY TAX**																	
47	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	$ 1,543,976	$ 971,747	$ 328,098	$ 122,100	$ 33,035	$ 43,544	$ 384	$ 12,074	$ 31,459	$ 192	$ 192	$ 192	$ 767	$ 192	$ -	$ -
48	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	$ 472,633	$ 272,956	$ 80,130	$ 95,509	$ 16,256	$ -	$ -	$ 2,877	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,157	$ 3,749
49	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	$ 382,748	$ 240,894	$ 81,335	$ 30,268	$ 8,189	$ 10,794	$ 95	$ 2,993	$ 7,799	$ 48	$ 48	$ 48	$ 190	$ 48	$ -	$ -
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	$ 375,384	$ 334,072	$ 37,711	$ 2,415	$ 661	$ 162	$ 1	$ 239	$ 117	$ 1	$ 1	$ 1	$ 3	$ 1	$ -	$ -
51	TOTAL PROPERTY TAX		$ 2,774,742	$ 1,819,669	$ 527,273	$ 250,293	$ 58,142	$ 54,501	$ 480	$ 18,183	$ 39,375	$ 240	$ 240	$ 240	$ 960	$ 240	$ 1,157	$ 3,749
52																		
53	Distribution-Demand-Secondary	NCP_SEC	$ (121,969)	$ (70,440)	$ (20,679)	$ (24,647)	$ (4,195)	$ -	$ -	$ (742)	$ -	$ -	$ -	$ -	$ -	$ -	$ (299)	$ (967)
54	Distribution-Customer-Meters	WTD_METE	$ (378,840)	$ (238,434)	$ (80,504)	$ (29,959)	$ (8,106)	$ (10,684)	$ (94)	$ (2,963)	$ (7,719)	$ (47)	$ (47)	$ (47)	$ (188)	$ (47)	$ -	$ -
55	Distribution-Customer-Other	CUSTS	$ (90,586)	$ (80,617)	$ (9,100)	$ (583)	$ (160)	$ (39)	$ (0)	$ (58)	$ (28)	$ (0)	$ (0)	$ (0)	$ (1)	$ (0)	$ -	$ -
56	TOTAL REVENUE CREDITS		$ (591,395)	$ (389,491)	$ (110,283)	$ (55,189)	$ (12,460)	$ (10,723)	$ (94)	$ (3,763)	$ (7,747)	$ (47)	$ (47)	$ (47)	$ (189)	$ (47)	$ (299)	$ (967)
57																		
58	Revenue Tax		$ 248,581	$ 163,296	$ 46,645	$ 22,579	$ 5,183	$ 5,047	$ 48	$ 1,598	$ 3,507	$ 21	$ 45	$ 21	$ 96	$ 21	$ 112	$ 362
59																		
60	Return on Rate Base		$ 15,368,203	$ 10,093,998	$ 2,846,854	$ 1,493,050	$ 330,158	$ 265,669	$ 2,341	$ 97,038	$ 191,937	$ 1,170	$ 1,170	$ 1,170	$ 4,681	$ 1,170	$ 8,915	$ 28,881
61	O&M		$ 11,338,213	$ 7,315,360	$ 2,117,429	$ 1,095,435	$ 245,153	$ 275,850	$ 3,202	$ 73,201	$ 171,764	$ 907	$ 5,625	$ 907	$ 6,240	$ 907	$ 6,188	$ 20,046
62	Depreciation Expense		$ 15,684,087	$ 10,440,231	$ 2,992,062	$ 1,241,637	$ 306,102	$ 331,984	$ 2,925	$ 102,302	$ 239,848	$ 1,462	$ 1,462	$ 1,462	$ 5,850	$ 1,462	$ 3,608	$ 11,688
63	Taxes Other Than Income		$ 3,023,323	$ 1,982,965	$ 573,918	$ 272,872	$ 63,325	$ 59,548	$ 529	$ 19,780	$ 42,882	$ 261	$ 285	$ 261	$ 1,056	$ 261	$ 1,269	$ 4,111
64	Net Allowable Federal Income Tax		$ 3,360,237	$ 2,208,431	$ 623,330	$ 323,624	$ 71,879	$ 58,698	$ 517	$ 21,250	$ 42,408	$ 259	$ 259	$ 259	$ 1,034	$ 259	$ 1,894	$ 6,136
65	Net Allowable State Income Tax		$ 944,067	$ 620,464	$ 175,126	$ 90,923	$ 20,195	$ 16,491	$ 145	$ 5,970	$ 11,915	$ 73	$ 73	$ 73	$ 291	$ 73	$ 532	$ 1,724
66	**TOTAL REVENUE REQUIREMENT**		$ 49,718,130	$ 32,661,449	$ 9,328,719	$ 4,517,541	$ 1,036,813	$ 1,008,241	$ 9,659	$ 319,542	$ 700,752	$ 4,132	$ 8,874	$ 4,132	$ 19,152	$ 4,132	$ 22,407	$ 72,586
67																		
68	**TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS**		$ 49,126,735	$ 32,271,958	$ 9,218,436	$ 4,462,352	$ 1,024,352	$ 997,518	$ 9,564	$ 315,779	$ 693,005	$ 4,085	$ 8,827	$ 4,085	$ 18,963	$ 4,085	$ 22,108	$ 71,619

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Line	Revenue Requirement	Class Allocator	PNM Retail	Schedule 1 Residential	Schedule 2 Small Power	Schedule 3B/3D General Power	Schedule 3C/3E GP Low LF	Schedule 4 Large Power	Schedule 5 Industrial Power	Schedule 10 Irrigation	Schedule 11 Water & Sewage	Schedule 15 Industrial Power	Schedule 30 Industrial Power	Schedule 33B Large Service	Schedule 35B Lg Power Service	Schedule 36B Special Service Rate	Schedule 6 Priv. Area Light	Schedule 20 Streetlighting
										Rate Schedules								
1	**GROSS PLANT**																	
2	TOTAL DISTRIBUTION PLANT - METERS	WTD_METE	$ 151,892,128	$ 95,597,795	$ 32,277,342	$ 12,011,887	$ 3,249,938	$ 4,283,750	$ 37,742	$ 1,187,838	$ 3,094,868	$ 18,871	$ 18,871	$ 18,871	$ 75,485	$ 18,871	$ -	$ -
3	TOTAL DISTRIBUTION PLANT - OTHER	NCP_SEC	$ 80,330,989	$ 46,392,982	$ 13,619,248	$ 16,233,129	$ 2,762,929	$ -	$ -	$ 488,906	$ -	$ -	$ -	$ -	$ -	$ -	$ 196,673	$ 637,122
4	TOTAL GENERAL & INTANGIBLE PLANT - SOFTWARE	WTD_METE	$ 57,328,411	$ 36,081,328	$ 12,182,387	$ 4,533,628	$ 1,226,619	$ 1,616,809	$ 14,245	$ 448,324	$ 1,168,091	$ 7,123	$ 7,123	$ 7,123	$ 28,490	$ 7,123	$ -	$ -
5	TOTAL GENERAL & INTANGIBLE PLANT - OTHER	CUSTS	$ 54,543,081	$ 48,540,472	$ 5,479,339	$ 350,954	$ 96,060	$ 23,546	$ 207	$ 34,662	$ 17,011	$ 104	$ 104	$ 104	$ 415	$ 104	$ -	$ -
6	**TOTAL GROSS PLANT**		$ 344,094,610	$ 226,612,577	$ 63,558,316	$ 33,129,597	$ 7,335,546	$ 5,924,105	$ 52,195	$ 2,159,729	$ 4,279,970	$ 26,097	$ 26,097	$ 26,097	$ 104,390	$ 26,097	$ 196,673	$ 637,122
7																		
8	**ACCUMULATED DEPRECIATION**																	
9	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION METERS	WTD_METE	$ (24,954,286)	$ (15,705,717)	$ (5,302,829)	$ (1,973,427)	$ (533,931)	$ (703,775)	$ (6,201)	$ (195,149)	$ (508,454)	$ (3,100)	$ (3,100)	$ (3,100)	$ (12,401)	$ (3,100)	$ -	$ -
10	TOTAL ACCUMULATED DEPRECIATION - DISTRIBUTION OTHER	NCP_SEC	$ (5,209,867)	$ (3,008,817)	$ (883,276)	$ (1,052,800)	$ (179,190)	$ -	$ -	$ (31,708)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,755)	$ (41,321)
11	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT SOFTWARE	WTD_METE	$ (16,060,486)	$ (10,108,141)	$ (3,412,881)	$ (1,270,090)	$ (343,636)	$ (452,947)	$ (3,991)	$ (125,597)	$ (327,239)	$ (1,995)	$ (1,995)	$ (1,995)	$ (7,981)	$ (1,995)	$ -	$ -
12	TOTAL ACCUMULATED DEPRECIATION - G&I PLANT OTHER	CUSTS	$ (9,331,664)	$ (8,304,690)	$ (937,449)	$ (60,044)	$ (16,435)	$ (4,028)	$ (35)	$ (5,930)	$ (2,910)	$ (18)	$ (18)	$ (18)	$ (71)	$ (18)	$ -	$ -
13	**TOTAL ACCUMULATED DEPRECIATION**		$ (55,556,303)	$ (37,127,365)	$ (10,536,436)	$ (4,356,361)	$ (1,073,191)	$ (1,160,751)	$ (10,227)	$ (358,385)	$ (838,604)	$ (5,113)	$ (5,113)	$ (5,113)	$ (20,454)	$ (5,113)	$ (12,755)	$ (41,321)
14																		
15	**ADIT**																	
16	TOTAL DISTRIBUTION ADIT - METERS	WTD_METE	$ (14,191,384)	$ (8,931,767)	$ (3,015,694)	$ (1,122,279)	$ (303,644)	$ (400,234)	$ (3,526)	$ (110,981)	$ (289,156)	$ (1,763)	$ (1,763)	$ (1,763)	$ (7,053)	$ (1,763)	$ -	$ -
17	TOTAL DISTRIBUTION ADIT - OTHER	NCP_SEC	$ (2,496,462)	$ (1,441,764)	$ (423,248)	$ (504,480)	$ (85,864)	$ -	$ -	$ (15,194)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,112)	$ (19,800)
18	TOTAL G&I ADIT SOFTWARE	WTD_METE	$ (7,371,299)	$ (4,639,344)	$ (1,566,414)	$ (582,935)	$ (157,719)	$ (207,890)	$ (1,832)	$ (57,646)	$ (150,193)	$ (916)	$ (916)	$ (916)	$ (3,663)	$ (916)	$ -	$ -
19	TOTAL G&I ADIT - OTHER	CUSTS	$ (3,920,607)	$ (3,489,134)	$ (393,860)	$ (25,227)	$ (6,905)	$ (1,693)	$ (15)	$ (2,492)	$ (1,223)	$ (7)	$ (7)	$ (7)	$ (30)	$ (7)	$ -	$ -
20	**TOTAL ADIT**		$ (27,979,752)	$ (18,502,009)	$ (5,399,216)	$ (2,234,921)	$ (554,132)	$ (609,816)	$ (5,373)	$ (186,311)	$ (440,572)	$ (2,686)	$ (2,686)	$ (2,686)	$ (10,746)	$ (2,686)	$ (6,112)	$ (19,800)
21																		
22	**TOTAL RATE BASE**		$ 260,558,554	$ 170,983,203	$ 47,622,664	$ 26,538,315	$ 5,708,223	$ 4,153,539	$ 36,595	$ 1,615,033	$ 3,000,794	$ 18,298	$ 18,298	$ 18,298	$ 73,190	$ 18,298	$ 177,806	$ 576,002
23	**RETURN ON RATE BASE**		$ 16,513,288	$ 10,836,316	$ 3,018,158	$ 1,681,905	$ 361,767	$ 263,237	$ 2,319	$ 102,355	$ 190,180	$ 1,160	$ 1,160	$ 1,160	$ 4,639	$ 1,160	$ 11,269	$ 36,505
24																		
25	**O&M**																	
26	TOTAL DISTRIBUTION O&M - METERS	WTD_METE	$ (6,034,122)	$ (3,797,752)	$ (1,282,261)	$ (477,189)	$ (129,108)	$ (170,178)	$ (1,499)	$ (47,188)	$ (122,948)	$ (750)	$ (750)	$ (750)	$ (2,999)	$ (750)	$ -	$ -
27	TOTAL DISTRIBUTION O&M - OTHER	NCP_SEC	$ 2,024,120	$ 1,168,976	$ 343,168	$ 409,030	$ 69,618	$ -	$ -	$ 12,319	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,956	$ 16,054
28	TOTAL GENERAL & INTANGIBLE O&M - SOFTWARE	WTD_METE	$ 9,252,331	$ 5,823,228	$ 1,966,136	$ 731,690	$ 197,966	$ 260,940	$ 2,299	$ 72,356	$ 188,520	$ 1,150	$ 1,150	$ 1,150	$ 4,598	$ 1,150	$ -	$ -
29	TOTAL GENERAL & INTANGIBLE O&M - OTHER	CUSTS	$ 1,373,614	$ 1,222,444	$ 137,992	$ 8,838	$ 2,419	$ 593	$ 5	$ 873	$ 428	$ 3	$ 3	$ 3	$ 10	$ 3	$ -	$ -
30	Distribution-Demand-Subs	NCP_SUBS	$ 172,099	$ 79,769	$ 23,417	$ 27,912	$ 4,751	$ 18,716	$ 1,450	$ 841	$ 6,156	$ -	$ 4,927	$ -	$ 2,727	$ -	$ 338	$ 1,095
31	Distribution-Demand-Primary	NCP_PRI	$ 473,144	$ 231,555	$ 67,976	$ 81,022	$ 13,790	$ 54,330	$ -	$ 2,440	$ 17,869	$ -	$ -	$ -	$ -	$ -	$ 982	$ 3,180
32	Distribution-Demand-Secondary	NCP_SEC	$ 266,749	$ 154,054	$ 45,224	$ 53,904	$ 9,175	$ -	$ -	$ 1,623	$ -	$ -	$ -	$ -	$ -	$ -	$ 653	$ 2,116
33	Distribution-Customer-Services	WTD_SERV	$ 28,255	$ 27,073	$ 1,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution-Customer-Meters	WTD_METE	$ 437,470	$ 275,335	$ 92,963	$ 34,596	$ 9,360	$ 12,338	$ 109	$ 3,421	$ 8,914	$ 54	$ 54	$ 54	$ 217	$ 54	$ -	$ -
35	Distribution-Customer-Other	CUSTS	$ 91,185	$ 81,150	$ 9,160	$ 587	$ 161	$ 39	$ 0	$ 58	$ 28	$ 0	$ 0	$ 0	$ 1	$ 0	$ -	$ -
36	TOTAL A&G		$ 1,468,902	$ 848,936	$ 239,923	$ 198,021	$ 37,236	$ 85,424	$ 1,559	$ 8,383	$ 32,967	$ 55	$ 4,982	$ 55	$ 2,945	$ 55	$ 1,973	$ 6,391
37	**TOTAL O&M**		$ 8,084,846	$ 5,265,831	$ 1,404,957	$ 870,391	$ 178,132	$ 176,778	$ 2,363	$ 46,743	$ 98,967	$ 457	$ 5,384	$ 457	$ 4,555	$ 457	$ 6,929	$ 22,445
38																		
39	**DEPRECIATION EXPENSE**																	
40	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - METERS	WTD_METE	$ 7,594,606	$ 4,779,890	$ 1,613,867	$ 600,594	$ 162,497	$ 214,188	$ 1,887	$ 59,392	$ 154,743	$ 944	$ 944	$ 944	$ 3,774	$ 944	$ -	$ -
41	TOTAL DISTRIBUTION DEPRECIATION EXPENSE - OTHER	NCP_SEC	$ 1,963,200	$ 1,133,793	$ 332,839	$ 396,720	$ 67,523	$ -	$ -	$ 11,948	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,806	$ 15,571
42	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - SOFTWARE	WTD_METE	$ 4,962,828	$ 3,123,502	$ 1,054,610	$ 392,469	$ 106,186	$ 139,965	$ 1,233	$ 38,811	$ 101,120	$ 617	$ 617	$ 617	$ 2,466	$ 617	$ -	$ -
43	TOTAL GENERAL & INTANGIBLE DPRECIATION EXPENSE - OTHER	CUSTS	$ 2,962,089	$ 2,636,104	$ 297,568	$ 19,059	$ 5,217	$ 1,279	$ 11	$ 1,882	$ 924	$ 6	$ 6	$ 6	$ 23	$ 6	$ -	$ -
44	**TOTAL DEPRECIATION EXPENSE**		$ 17,482,724	$ 11,673,289	$ 3,298,884	$ 1,408,842	$ 341,423	$ 355,431	$ 3,132	$ 112,033	$ 256,787	$ 1,566	$ 1,566	$ 1,566	$ 6,263	$ 1,566	$ 4,806	$ 15,571
45																		
46	**PROPERTY TAX**																	
47	TOTAL DISTRIBUTION PROPERTY TAX - METERS	WTD_METE	$ 1,479,857	$ 931,392	$ 314,472	$ 117,030	$ 31,664	$ 41,736	$ 368	$ 11,573	$ 30,153	$ 184	$ 184	$ 184	$ 735	$ 184	$ -	$ -
48	TOTAL DISTRIBUTION PROPERTY TAX - OTHER	NCP_SEC	$ 650,699	$ 375,794	$ 110,319	$ 131,492	$ 22,380	$ -	$ -	$ 3,960	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,593	$ 5,161
49	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - SOFTWARE	WTD_METE	$ 339,135	$ 213,445	$ 72,067	$ 26,819	$ 7,256	$ 9,564	$ 84	$ 2,652	$ 6,910	$ 42	$ 42	$ 42	$ 169	$ 42	$ -	$ -
50	TOTAL GENERAL & INTANGIBLE PROPERTY TAX - OTHER	CUSTS	$ 439,730	$ 391,336	$ 44,175	$ 2,829	$ 774	$ 190	$ 2	$ 279	$ 137	$ 1	$ 1	$ 1	$ 3	$ 1	$ -	$ -
51	TOTAL PROPERTY TAX		$ 2,909,421	$ 1,911,967	$ 541,033	$ 278,170	$ 62,075	$ 51,490	$ 454	$ 18,465	$ 37,200	$ 227	$ 227	$ 227	$ 907	$ 227	$ 1,593	$ 5,161
52																		
53	Distribution-Demand-Secondary	NCP_SEC	$ (138,065)	$ (79,736)	$ (23,407)	$ (27,900)	$ (4,749)	$ -	$ -	$ (840)	$ -	$ -	$ -	$ -	$ -	$ -	$ (338)	$ (1,095)
54	Distribution-Customer-Meters	WTD_METE	$ (359,587)	$ (226,317)	$ (76,413)	$ (28,437)	$ (7,694)	$ (10,141)	$ (89)	$ (2,812)	$ (7,327)	$ (45)	$ (45)	$ (45)	$ (179)	$ (45)	$ -	$ -
55	Distribution-Customer-Other	CUSTS	$ (93,743)	$ (83,426)	$ (9,417)	$ (603)	$ (165)	$ (40)	$ (0)	$ (60)	$ (29)	$ (0)	$ (0)	$ (0)	$ (1)	$ (0)	$ -	$ -
56	TOTAL REVENUE CREDITS		$ (591,395)	$ (389,479)	$ (109,238)	$ (56,940)	$ (12,608)	$ (10,182)	$ (90)	$ (3,712)	$ (7,356)	$ (45)	$ (45)	$ (45)	$ (179)	$ (45)	$ (338)	$ (1,095)
57																		
58	Revenue Tax		$ 249,364	$ 164,477	$ 45,781	$ 23,646	$ 5,247	$ 4,636	$ 45	$ 1,549	$ 3,203	$ 19	$ 44	$ 19	$ 89	$ 19	$ 139	$ 450
59																		
60	Return on Rate Base		$ 16,513,288	$ 10,836,316	$ 3,018,158	$ 1,681,905	$ 361,767	$ 263,237	$ 2,319	$ 102,355	$ 190,180	$ 1,160	$ 1,160	$ 1,160	$ 4,639	$ 1,160	$ 11,269	$ 36,505
61	O&M		$ 8,084,846	$ 5,265,831	$ 1,404,957	$ 870,391	$ 178,132	$ 176,778	$ 2,363	$ 46,743	$ 98,967	$ 457	$ 5,384	$ 457	$ 4,555	$ 457	$ 6,929	$ 22,445
62	Depreciation Expense		$ 17,482,724	$ 11,673,289	$ 3,298,884	$ 1,408,842	$ 341,423	$ 355,431	$ 3,132	$ 112,033	$ 256,787	$ 1,566	$ 1,566	$ 1,566	$ 6,263	$ 1,566	$ 4,806	$ 15,571
63	Taxes Other Than Income		$ 3,158,785	$ 2,076,443	$ 586,814	$ 301,816	$ 67,322	$ 56,126	$ 499	$ 20,014	$ 40,403	$ 246	$ 271	$ 246	$ 996	$ 246	$ 1,732	$ 5,611
64	Net Allowable Federal Income Tax		$ 3,616,927	$ 2,375,506	$ 662,109	$ 364,661	$ 78,821	$ 58,427	$ 515	$ 22,456	$ 42,211	$ 257	$ 257	$ 257	$ 1,030	$ 257	$ 2,397	$ 7,764
65	Net Allowable State Income Tax		$ 1,016,184	$ 667,404	$ 186,021	$ 102,452	$ 22,145	$ 16,415	$ 145	$ 6,309	$ 11,859	$ 72	$ 72	$ 72	$ 289	$ 72	$ 673	$ 2,181
66	**TOTAL REVENUE REQUIREMENT**		$ 49,872,754	$ 32,894,790	$ 9,156,944	$ 4,730,068	$ 1,049,610	$ 926,414	$ 8,972	$ 309,910	$ 640,408	$ 3,758	$ 8,710	$ 3,758	$ 17,772	$ 3,758	$ 27,806	$ 90,077
67																		
68	**TOTAL REVENUE REQUIREMENT W/ REVENUE CREDITS**		$ 49,281,359	$ 32,505,311	$ 9,047,706	$ 4,673,129	$ 1,037,003	$ 916,232	$ 8,883	$ 306,198	$ 633,052	$ 3,713	$ 8,665	$ 3,713	$ 17,592	$ 3,713	$ 27,468	$ 88,982

PNM Exhibit SC-4: GMR Charge by Customer Class by Year **Page 1 of 6**

Year 1 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 1	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)
		[B]	[C] = [B] / 12	[D]	[E] = [D] / [C]	[F] = [D] / [B]
1	1 - Residential	5,615,569	467,964	$6,513,990	$13.92	$1.16
2	2 - Small Power	633,896	52,825	$1,820,381	$34.46	$2.87
3	3B / 3D - General Power	40,601	3,383	$768,936	$227.26	$18.94
4	3C / 3E - General Power Low LF	11,113	926	$186,867	$201.78	$16.82
5	4B - Large Power	2,724	227	$254,744	$1,122.22	$93.52
6	5B - Lg. Svc. (8 MW)	24	2	$2,897	$1,448.39	$120.70
7	10A/B - Irrigation	4,010	334	$61,502	$184.05	$15.34
8	11B - Wtr/Swg Pumping	1,968	164	$160,776	$980.34	$81.69
9	15B - Universities 115 kV	12	1	$862	$861.77	$71.81
10	30B - Manuf. (30 MW)	12	1	$4,850	$4,849.55	$404.13
11	33B - Lg. Svc. (Station Power)	12	1	$862	$861.77	$71.81
12	35B - Lg. Svc. (3 MW)	48	4	$5,654	$1,413.56	$117.80
13	36B - SSR - Renew. Energy Res.	12	1	$862	$861.77	$71.81
14	6 - Private Area Lighting*	92,436	7,703	$2,561	$0.33	$0.03
15	20 - Streetlighting*	597,720	49,810	$8,296	$0.17	$0.01
16						
17	Total	7,000,157	583,346	$9,794,037		

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-4: GMR Charge by Customer Class by Year

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Year 2 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 2	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)	GMR monthly charge, % increase from Year 1 charge
		[G]	[H] = [G] / 12	[I]	[J] = [I] / [H]	[K] = [I] / [G]	[L] = ([K] - [F]) / [F]
1	1 - Residential	5,615,569	467,964	$12,526,674	$26.77	$2.23	92.3%
2	2 - Small Power	633,896	52,825	$3,572,230	$67.62	$5.64	96.2%
3	3B / 3D - General Power	40,601	3,383	$1,611,053	$476.16	$39.68	109.5%
4	3C / 3E - General Power Low LF	11,113	926	$381,644	$412.11	$34.34	104.2%
5	4B - Large Power	2,724	227	$437,889	$1,929.02	$160.75	71.9%
6	5B - Lg. Svc. (8 MW)	24	2	$4,539	$2,269.61	$189.13	56.7%
7	10A/B - Irrigation	4,010	334	$122,101	$365.40	$30.45	98.5%
8	11B - Wtr/Swg Pumping	1,968	164	$292,063	$1,780.87	$148.41	81.7%
9	15B - Universities 115 kV	12	1	$1,657	$1,657.07	$138.09	92.3%
10	30B - Manuf. (30 MW)	12	1	$5,821	$5,821.11	$485.09	20.0%
11	33B - Lg. Svc. (Station Power)	12	1	$1,657	$1,657.07	$138.09	92.3%
12	35B - Lg. Svc. (3 MW)	48	4	$8,933	$2,233.24	$186.10	58.0%
13	36B - SSR - Renew. Energy Res.	12	1	$1,657	$1,657.07	$138.09	92.3%
14	6 - Private Area Lighting*	92,436	7,703	$6,556	$0.85	$0.07	156.0%
15	20 - Streetlighting*	597,720	49,810	$21,237	$0.43	$0.04	156.0%
16							
17	Total	7,000,157	583,346	$18,995,710			

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-4: GMR Charge by Customer Class by Year

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Year 3 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 3	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)	GMR monthly charge, % increase from Year 2 charge
		[M]	[N] = [M] / 12	[O]	[P] = [O] / [N]	[Q] = [O] / [M]	[R] = ([Q] - [K]) / [K]
1	1 - Residential	5,615,569	467,964	$22,725,510	$48.56	$4.05	81.4%
2	2 - Small Power	633,896	52,825	$6,491,764	$122.89	$10.24	81.7%
3	3B / 3D - General Power	40,601	3,383	$2,938,872	$868.60	$72.38	82.4%
4	3C / 3E - General Power Low LF	11,113	926	$695,203	$750.69	$62.56	82.2%
5	4B - Large Power	2,724	227	$747,261	$3,291.90	$274.32	70.7%
6	5B - Lg. Svc. (8 MW)	24	2	$7,295	$3,647.55	$303.96	60.7%
7	10A/B - Irrigation	4,010	334	$222,060	$664.53	$55.38	81.9%
8	11B - Wtr/Swg Pumping	1,968	164	$514,499	$3,137.19	$261.43	76.2%
9	15B - Universities 115 kV	12	1	$3,008	$3,007.91	$250.66	81.5%
10	30B - Manuf. (30 MW)	12	1	$7,356	$7,356.16	$613.01	26.4%
11	33B - Lg. Svc. (Station Power)	12	1	$3,008	$3,007.91	$250.66	81.5%
12	35B - Lg. Svc. (3 MW)	48	4	$14,438	$3,609.57	$300.80	61.6%
13	36B - SSR - Renew. Energy Res.	12	1	$3,008	$3,007.91	$250.66	81.5%
14	6 - Private Area Lighting*	92,436	7,703	$12,078	$1.57	$0.13	84.2%
15	20 - Streetlighting*	597,720	49,810	$39,126	$0.79	$0.07	84.2%
16							
17	Total	7,000,157	583,346	$34,424,486			

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-4: GMR Charge by Customer Class by Year

Year 4 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 4	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)	GMR monthly charge, % increase from Year 3 charge
		[S]	[T] = [S] / 12	[U]	[V] = [U] / [T]	[W] = [U] / [S]	[X] = ([W] - [Q]) / [Q]
1	1 - Residential	5,615,569	467,964	$29,874,313	$63.84	$5.32	31.5%
2	2 - Small Power	633,896	52,825	$8,628,582	$163.34	$13.61	32.9%
3	3B / 3D - General Power	40,601	3,383	$3,985,929	$1,178.07	$98.17	35.6%
4	3C / 3E - General Power Low LF	11,113	926	$936,707	$1,011.47	$84.29	34.7%
5	4B - Large Power	2,724	227	$972,857	$4,285.71	$357.14	30.2%
6	5B - Lg. Svc. (8 MW)	24	2	$9,314	$4,657.11	$388.09	27.7%
7	10A/B - Irrigation	4,010	334	$296,950	$888.64	$74.05	33.7%
8	11B - Wtr/Swg Pumping	1,968	164	$676,362	$4,124.16	$343.68	31.5%
9	15B - Universities 115 kV	12	1	$3,989	$3,989.15	$332.43	32.6%
10	30B - Manuf. (30 MW)	12	1	$8,530	$8,529.90	$710.82	16.0%
11	33B - Lg. Svc. (Station Power)	12	1	$3,989	$3,989.15	$332.43	32.6%
12	35B - Lg. Svc. (3 MW)	48	4	$18,470	$4,617.45	$384.79	27.9%
13	36B - SSR - Renew. Energy Res.	12	1	$3,989	$3,989.15	$332.43	32.6%
14	6 - Private Area Lighting*	92,436	7,703	$17,125	$2.22	$0.19	41.8%
15	20 - Streetlighting*	597,720	49,810	$55,478	$1.11	$0.09	41.8%
16							
17	Total	7,000,157	583,346	$45,492,585			

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-4: GMR Charge by Customer Class by Year

Year 5 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 5	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)	GMR monthly charge, % increase from Year 4 charge
		[Y]	[Z] = [Y] / 12	[AA]	[AB] = [AA] / [Z]	[AC] = [AA] / [Y]	[AD] = ([AC] - [W]) / [W]
1	1 - Residential	5,615,569	467,964	$32,271,958	$68.96	$5.75	8.0%
2	2 - Small Power	633,896	52,825	$9,218,436	$174.51	$14.54	6.8%
3	3B / 3D - General Power	40,601	3,383	$4,462,352	$1,318.88	$109.91	12.0%
4	3C / 3E - General Power Low LF	11,113	926	$1,024,352	$1,106.11	$92.18	9.4%
5	4B - Large Power	2,724	227	$997,518	$4,394.35	$366.20	2.5%
6	5B - Lg. Svc. (8 MW)	24	2	$9,564	$4,782.20	$398.52	2.7%
7	10A/B - Irrigation	4,010	334	$315,779	$944.99	$78.75	6.3%
8	11B - Wtr/Swg Pumping	1,968	164	$693,005	$4,225.64	$352.14	2.5%
9	15B - Universities 115 kV	12	1	$4,085	$4,084.65	$340.39	2.4%
10	30B - Manuf. (30 MW)	12	1	$8,827	$8,826.55	$735.55	3.5%
11	33B - Lg. Svc. (Station Power)	12	1	$4,085	$4,084.65	$340.39	2.4%
12	35B - Lg. Svc. (3 MW)	48	4	$18,963	$4,740.78	$395.07	2.7%
13	36B - SSR - Renew. Energy Res.	12	1	$4,085	$4,084.65	$340.39	2.4%
14	6 - Private Area Lighting*	92,436	7,703	$22,108	$2.87	$0.24	29.1%
15	20 - Streetlighting*	597,720	49,810	$71,619	$1.44	$0.12	29.1%
16							
17	Total	7,000,157	583,346	$49,126,735			

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-4: GMR Charge by Customer Class by Year

Year 6 Revenue Requirement

Year	Annual Revenue Requirement
Year 1	$9,794,037
Year 2	$18,995,710
Year 3	$34,424,486
Year 4	$45,492,585
Year 5	$49,126,735
Year 6	$49,281,359
	[A]

Line	Customer Class	Annual number of customers 16-00276-UT as filed	Monthly number of customers/ number of lights	Customer Class revenue requirement Year 6	GMR annual charge ($/customer bill)	GMR monthly charge ($/customer bill)	GMR monthly charge, % increase from Year 5 charge
		[AE]	[AF] = [AE] / 12	[AG]	[AH] = [AG] / [AF]	[AI] = [AG] / [AE]	[AJ] = ([AI] - [AC]) / [AC]
1	1 - Residential	5,615,569	467,964	$32,505,311	$69.46	$5.79	0.7%
2	2 - Small Power	633,896	52,825	$9,047,706	$171.28	$14.27	-1.9%
3	3B / 3D - General Power	40,601	3,383	$4,673,129	$1,381.18	$115.10	4.7%
4	3C / 3E - General Power Low LF	11,113	926	$1,037,003	$1,119.77	$93.31	1.2%
5	4B - Large Power	2,724	227	$916,232	$4,036.26	$336.36	-8.1%
6	5B - Lg. Svc. (8 MW)	24	2	$8,883	$4,441.30	$370.11	-7.1%
7	10A/B - Irrigation	4,010	334	$306,198	$916.32	$76.36	-3.0%
8	11B - Wtr/Swg Pumping	1,968	164	$633,052	$3,860.07	$321.67	-8.7%
9	15B - Universities 115 kV	12	1	$3,713	$3,712.84	$309.40	-9.1%
10	30B - Manuf. (30 MW)	12	1	$8,665	$8,664.94	$722.08	-1.8%
11	33B - Lg. Svc. (Station Power)	12	1	$3,713	$3,712.84	$309.40	-9.1%
12	35B - Lg. Svc. (3 MW)	48	4	$17,592	$4,398.06	$366.50	-7.2%
13	36B - SSR - Renew. Energy Res.	12	1	$3,713	$3,712.84	$309.40	-9.1%
14	6 - Private Area Lighting*	92,436	7,703	$27,468	$3.57	$0.30	24.2%
15	20 - Streetlighting*	597,720	49,810	$88,982	$1.79	$0.15	24.2%
16							
17	Total	7,000,157	583,346	$49,281,359			

* A $/light charge for Rate 6 Private Area Lighting and Rate 20 Streetlighting will be applied.

PNM Exhibit SC-5
GMR Bill Impacts

1A - Residential				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
500 kWh	$68.93	$70.13	$1.20	1.744%
750 kWh	$107.49	$108.69	$1.20	1.118%
1,000 kWh	$147.85	$149.05	$1.20	0.813%

1B - Residential TOU				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
500 kWh	$96.10	$97.30	$1.20	1.251%
750 kWh	$130.41	$131.61	$1.20	0.922%
1,000 kWh	$164.72	$165.93	$1.20	0.730%

2A - Small Power				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
500 kWh	$85.88	$88.86	$2.98	3.466%
1,500 kWh	$224.95	$227.93	$2.98	1.323%
5,000 kWh	$711.71	$714.68	$2.98	0.418%

2B - Small Power TOU				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
1,500 kWh	$228.98	$231.95	$2.98	1.300%
5,000 kWh	$725.09	$728.07	$2.98	0.410%
10,000 kWh	$1,433.83	$1,436.81	$2.98	0.208%

3B / 3D - General Power TOU				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
30,000 kWh and 50 kW	$2,960.30	$2,979.93	$19.63	0.663%
50,000 kWh and 75 kW	$4,681.97	$4,701.60	$19.63	0.419%
75,000 kWh and 150 kW	$7,844.71	$7,864.34	$19.63	0.250%

3C / 3E - General Power Low Load Factor TOU				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
10,000 kWh and 50 kW	$1,632.07	$1,649.50	$17.43	1.068%
12,000 kWh and 50 kW	$1,857.81	$1,875.23	$17.43	0.938%
15,000 kWh and 75 kW	$2,405.66	$2,423.09	$17.43	0.724%

4B - Large Power Service TOU				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
150,000 kWh and 500 kW	$20,071.59	$20,168.51	$96.92	0.483%
500,000 kWh and 1,500 kW	$61,900.33	$61,997.25	$96.92	0.157%
1,500,000 kWh and 2,500 kW	$140,736.58	$140,833.49	$96.92	0.069%

5B - Large Service for Customers >= 8,000kW min. at 115kV, 69kV or 34.5kV				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
2,000,000 kWh and 8,000 kW	$233,258.77	$233,379.81	$121.05	0.052%
2,500,000 kWh and 10,000 kW	$289,240.25	$289,361.29	$121.05	0.042%

10A Irrigation Service				
Consumption Level	Average Monthly Bill at Present Rates	Average Monthly Bill with GMR	$ Change	% Change
1,500 kWh	$185.26	$201.15	$15.90	8.580%
3,500 kWh	$418.32	$434.22	$15.90	3.800%
6,000 kWh	$709.66	$725.55	$15.90	2.240%

PNM Exhibit SC-5

GMR Bill Impacts

10B Irrigation Service TOU				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
5,000 kWh	$301.78	$317.67	$15.90	5.267%
7,500 kWh	$447.44	$463.33	$15.90	3.553%
10,000 kWh	$593.10	$608.99	$15.90	2.680%

11B Water and Sewage Pumping Service TOU				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
75,000 kWh	$6,744.37	$6,829.04	$84.67	1.255%
90,000 kWh	$7,998.83	$8,083.50	$84.67	1.058%
150,000 kWh	$13,016.67	$13,101.34	$84.67	0.650%

15B Large Service for Public Universities > 8,000kW min. at 115kV				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
2,000,000 kWh and 8,000 kW	$227,184.40	$227,256.42	$72.02	0.032%
4,500,000 kWh and 12,000 kW	$407,054.85	$407,126.87	$72.02	0.018%

30B Large Service for Manufacturing >= 30,000kW minimum at distribution voltage				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
25,000,000 kWh and 40,000 kW	$2,046,107.57	$2,046,512.86	$405.29	0.020%
25,000,000 kWh and 45,000 kW	$2,163,018.12	$2,163,423.41	$405.29	0.019%
30,000,000 kWh and 50,000 kW	$2,496,181.85	$2,496,587.14	$405.29	0.016%

33B Large Service for Station Power TOU				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
200,000 kWh and 500 kW	$13,481.36	$13,555.79	$74.43	0.552%
300,000 kWh and 500 kW	$18,720.18	$18,794.60	$74.43	0.398%
400,000 kWh and 750 kW	$25,233.82	$25,308.24	$74.43	0.295%

35B Large Power Service >= 3,000kW TOU				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
2,000,000 kWh and 3,000 kW	$151,473.91	$151,595.99	$122.08	0.081%
3,000,000 kWh and 5,000 kW	$234,015.34	$234,133.48	$118.13	0.050%
4,000,000 kWh and 7,000 kW	$315,161.32	$315,279.46	$118.13	0.037%

36B Special Service Rate - Renewable Energy Resources				
	Average Monthly Bill at	Average Monthly Bill		
Consumption Level	Present Rates	with GMR	$ Change	% Change
38,963,000 kWh and 61,000 kW	$1,181,678	$1,181,750	$71.81	0.006%
47,618,000 kWh and 73,000 kW	$1,437,300	$1,437,372	$71.81	0.005%
55,278,000 kWh and 88,000 kW	$1,680,615	$1,680,687	$71.81	0.004%

Lighting rate classes	
	GMR rate per light
Per Light	($/kWh)
6 - Private Area Lights	$0.03
20 - Streetlighting	$0.01

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	)	**Case No. 22-00058-UT**

SELF AFFIRMATION

STELLA CHAN, Director of Pricing and Strategic Customer Marketing for Public Service Company of New Mexico, upon penalty of perjury under the laws of the State of New Mexico, affirm and state: I have read the foregoing: **Direct Testimony of Stall Chan** and it is true and accurate based on my own personal knowledge and belief.

DATED this 3rd day of October, 2022.

/s/ Stella Chan

STELLA CHAN

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND APPLICATION TO RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF	))))))))	**Case No. 22-00058-UT**

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of **Public Service Company of New Mexico's Application for Authorization to Implement Grid Modernization Components That Include Advanced Metering Infrastructure and Application to Recover the Associated Costs Through a Rider, Issuance of Related Accounting Orders, and Other Associated Relief** was emailed to the parties listed below on October 3, 2022:

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Dated this 3rd day of October, 2022.

By: /s/Brian Buffington
Brian Buffington, Senior Project Manager
PNM Regulatory Policy & Case Management
Public Service Company of New Mexico