Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Final Report

Avoided Cost of Transmission and Distribution Capacity Study

Prepared for PNM
By Demand Side Analytics
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ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

A vital role of utilities is to ensure that the electricity supply remains reliable by projecting future demand and reinforcing the transmission and distribution (T&D) network at various levels – substations, transformer banks, feeders, and service transformers – so the capacity is available to meet local needs as demand evolves. The energy industry is experiencing rapid technological change, particularly with the introduction of distributed energy resources and the electrification of space heating and transportation. The shift affects (1) how, when, and where customers use electricity and (2) how, when, and where electricity is produced. Many factors can influence distribution planning processes, including:

- The adoption of electric vehicles.
- Building electrification initiatives.
- The adoption of distributed solar, including community solar.
- The introduction of battery storage.
- Customer growth and migration patterns.
- New appliance standards and building codes.
- Program-based introduction of energy efficiency.
- An increase in connected devices and flexibility in loads.

In this future electric system, where grid operators have less control over supply, load flexibility and load shaping will become increasingly valuable. Ultimately, PNM will need to either build out the capacity to serve the increased loads or develop strategies to manage loads to mitigate the need for load growth-driven distribution upgrades. The goal of this T&D avoided cost study is to develop values for load growth-related T&D costs that are avoidable by implementing mitigation strategies such as demand side management.

In addition, PNM must define the avoided T&D costs specific to EE for use in evaluating the cost-effectiveness of EE programs. Peak demand reductions from EE programs can avoid or defer capital upgrades to assets that are at or near capacity (i.e., highly loaded). Essentially, infrastructure upgrades can be temporarily avoided or deferred via load relief, but cannot be avoided indefinitely because equipment eventually ages and needs to be replaced. Further, the potential for such deferral value is a function of the EE savings load shape and its coincidence with the shape of overload risk. This study seeks to quantify the general deferral value and value of Energy Efficiency on PNM transmission and distribution investments. The study outputs are designed to inform planning activities and the evaluation of program cost-effectiveness.

The focus of the study is to quantify the T&D costs associated with an increase, or decrease, in coincident peak demand. The study employs methodologies that are novel for New Mexico but have been applied in New York, California, and Pennsylvania for load forecasting and distributed energy resource (DER) valuation. Local demand trajectories based on historical loads are inherently uncertain and those forecasts grow more uncertain further into the future. The probabilistic deferral methodology for estimating avoided distribution costs incorporates this uncertainty directly.

While the final study outputs are territory-wide average values for PNM, the granular forecasts can help identify locations and timing when demand reductions or injections of distributed generation are beneficial. However, the focus of this study is to quantify deferrable transmission and distribution costs. The analysis undertaken to quantify avoidable T&D costs is not a substitute for the engineering analysis required to inform decisions on transmission and distribution infrastructure investments. The planning engineering analysis is more comprehensive, updated more frequently, and supersedes the analysis undertaken as part of this study.

Table 1 shows the deferral of transmission and distribution capacity results for the twenty years of the study horizon, as well as the 10-year levelized value from 2028 to 2037. From 2026 to 2045, the total deferral value increases from $1.73/kW-year to $66.59/kW-year, peaking at $81.43/kW-year in 2039. The distribution value is consistently lower than the transmission value. Both components of the distribution value, the distribution feeder and the substation transformer values, as well as the transmission value show a steady increase initially but decreases towards the end of the study period. This trend may be attributed to the expectation that many sites will exceed their maximum deferral periods by around 2040, at which point these sites will be considered non-deferrable, thereby necessitating infrastructure investments.

Table 1: PNM Deferral Value (load-weighted average, nominal $/kW-year)

Year	Distribution		Transmission	Total
	Feeder	Substation Transformer		
2026	$1.73	$0.00	$0.00	$1.73
2027	$1.70	$0.82	$0.00	$2.51
2028	$2.51	$4.44	$28.96	$35.91
2029	$3.82	$7.72	$27.72	$39.26
2030	$4.80	$9.32	$27.60	$41.72
2031	$5.71	$10.23	$27.53	$43.48
2032	$6.54	$11.90	$48.17	$66.61
2033	$8.19	$13.73	$48.12	$70.04
2034	$9.17	$14.81	$47.03	$71.02
2035	$10.43	$15.86	$47.06	$73.35
2036	$9.83	$16.52	$50.78	$77.13
2037	$10.21	$16.46	$50.17	$76.85
2038	$10.62	$14.89	$45.43	$70.94
2039	$10.31	$14.31	$56.72	$81.34
2040	$10.49	$14.72	$46.47	$71.68
2041	$11.01	$15.31	$46.50	$72.82
2042	$10.55	$15.17	$47.73	$73.45
2043	$10.80	$15.82	$47.63	$74.25
2044	$9.63	$14.32	$47.60	$71.55
2045	$8.18	$12.69	$45.72	$66.59
10-year levelized value (2028-2037, $2025)	**$6.51**	**$10.89**	**$35.76**	**$53.16**

Notably, the most imminent investments, those with high risk in the next one to three years, are largely not deferrable. This means that the avoided cost is also a function of the period over which investment deferral is valued. Table 2 shows 10-year levelized deferral value as a function of the ten-year valuation period start year. Selecting a later start year means that there is more value in all ten valuation years, which translates to as much as double the value.

Table 2: PNM 10-Year Levelized Deferral Value Sensitivity to Valuation Start Year (load-weighted average, nominal $/kW-year)

Start Year for 10-Year Levelized Value	Distribution		Transmission	Total
	Feeder	Substation Transformer		
2026	$4.75	$7.46	$24.38	$36.58
2027	$5.59	$9.17	$29.83	$44.60
2028	$6.51	$10.89	$35.76	$53.16
2029	$7.42	$12.14	$37.87	$57.42
2030	$8.16	$13.09	$41.08	$62.34
2031	$8.83	$13.89	$40.43	$63.15
2032	$9.45	$14.59	$43.22	$67.26
2033	$9.95	$15.03	$45.41	$70.39
2034	$10.25	$15.26	$46.04	$71.55
2035	$10.36	$15.27	$46.54	$72.18

Based on discussions with PNM transmission and distribution planners and a review of the historic and projected investments, the DSA team selected the deferral approach for both transmission and distribution. The T&D deferral value approach focuses on quantifying the value of load relief on ratepayer costs (i.e., revenue requirements). The DSA team then applied the seasonal load shapes to allocate the deferral values across the 24 hours of both the summer and winter seasons. Summer peaks are generally a function of hot weather in June, July, and August. Winter peaks are caused by cold weather typically in December, January, and February.

The list below summarizes central study findings. The DSA team ultimately aggregated the granular results into system-wide values. Section 4 of the report includes a more detailed discussion of each finding and lays out some potential enhancements that would better reflect the variability in value across locations.

1. Load growth varies by location. Some pockets are experiencing load growth, and some are experiencing load decreases.
2. The locational dispersion of the EE forecast used for this study lacked geospatial granularity. Most EE rebates are point-of-sale transactions, and PNM has data on the stores where the transactions occurred but lacks data on the customers who purchased the equipment. Geospatial tracking of EE in the future would improve the precision of estimates of EE by location, deferral value, and Value of EE in future studies.
3. The T&D avoided costs are concentrated in locations that are more heavily loaded.
4. Most Individual locations are summer peaking, some are winter peaking, and only a few are dual peaking.

5. Resources that deliver load relief at the right location, in the right season, and at the right hours are more valuable.
6. The most imminent investments, those with high risk in the next one to three years, are largely not deferrable, so deferral value is sensitive to the deferral value period.

Based on the analysis, the DSA team recommends the proposed values shown in Table 3 for future incorporation into future cost-effectiveness analyses of PNM programs. The avoided cost of T&D reflects the value to the system of unconstrained resources. The Value of EE reflects the ability of EE resources to deliver T&D value given load shape constraints of the expected PNM EE portfolio. The 10-year levelized value shown summarizes annual values that will be in practice will be applied to useful life of modifiers being valued. The Value of LM reflects the ability of Load Management resources to deliver T&D value given the mostly summer capacity of the PNM LM portfolio.

Table 3: Recommended PNM Avoided T&D Values ($2025)

Type of Value	Description	Transmission	Distribution
Avoided T&D	10-year levelized value (2028-2037, $2025)	$35.76	$17.40
Value of EE	10-year levelized value (2028-2037, $2025)	$22.80	$9.71
Value of LM	9-year levelized value (2027-2035, $2025)	$30.88	$13.26

1 INTRODUCTION

This study focuses on the avoided cost of transmission and distribution (T&D) capacity. When loads grow, the available T&D capacity dwindles. If an energy efficiency (EE) or demand response (DR) program helps reduce coincident demand, the unused capacity can accommodate another customer's load growth, thereby helping to avoid or defer investments required to meet load growth. Avoided or deferred investments free up capital for alternate uses, improving the efficient use of resources. With deferral, infrastructure costs are not incorporated into the rate base and customer bills until a later date, leading to lower customer bills in the immediate years.

1.1 STUDY BACKGROUND AND OBJECTIVES

The Efficient Use of Energy Act (EUEA) currently requires PNM to use the Utility Cost Test (UCT) to evaluate the cost-effectiveness of PNM's energy efficiency and demand response programs. The UCT compares the net present value (NPV) of future utility benefits – namely, avoided generation capacity value and avoided transmission and distribution (T&D) capacity value (deferral value) – to the first-year cost of implementing the programs. Historically, PNM has used a proxy value for avoided T&D costs, but with recent directives from the New Mexico Public Regulation Commission (PRC) in the Final Order of Case 23-00138-UT, PNM sought to develop more accurate T&D cost figures based on PNM-specific data.[1] As such, PNM contracted with DSA to conduct this T&D avoided cost study, with a key objective of replacing the current regional proxy T&D avoided cost values with PNM-specific results. The findings from this study will ultimately be used as part of the annual cost-effectiveness evaluation of PNM's energy efficiency and demand response portfolio.

Since the focus of the study is on T&D avoided costs, the study was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level
- Model location-specific forecasts of growth inclusive of the inherent uncertainty in future growth projections
- Quantify the probability that infrastructure upgrades will be needed at specific locations
- Calculate avoided distribution costs (deferral value) by year and location
- Identify beneficial locations for demand reductions

Although not the primary study objective, the PRC and stakeholders might use the study outputs to understand the increased T&D costs associated with space heating and/or transportation electrification

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[1] Additional background regarding the T&D avoided cost study directive is publicly available on the PRC's case lookup e-docket. Available at https://www.prc.nm.gov/case-lookup-e-docket/

policies. The granular location-specific deferral value estimates could also be used to explore the economics of Non-Wire Alternative (NWA) projects such as battery storage.

There are several aspects of the study that make it unique. First, separate avoided cost estimates are produced for each location on PNM's local distribution system. In areas with excess capacity or declining loads, the value of peak demand reduction can be minimal. In areas where a large, growth-related investment is imminent, the value of peak demand reduction can be quite substantial. Second, the study estimates historical year-to-year growth patterns and variability in growth for individual areas. Third, load growth forecasts and avoided cost estimates are developed using probabilistic methods rather than straight-line forecasts. This approach considers the reality that there is much greater uncertainty ten years out than a year out, and it accounts for the risk mitigation value of resources that manage local peak demand. The study approach is a departure from the current planning practices in use by PNM planners. As such, differences are to be expected in the overloads and projects identified by this study relative to the overloads and projects identified by the current PNM planning processes.

1.2 ABOUT PNM

As New Mexico's largest electricity provider, PNM provides electric service to more than 550,000 New Mexico residential and business customers in greater Albuquerque, Rio Rancho, Los Lunas and Belen, Santa Fe, Las Vegas, Alamogordo, Ruidoso, Silver City, Deming, Bayard, Lordsburg and Clayton. PNM also serves the New Mexico tribal communities of the Tesuque, Cochiti, Santo Domingo, San Felipe, Santa Ana, Sandia, Isleta and Laguna Pueblos.

1.2.1 SYSTEM DETAILS

The PNM system consists of approximately 504 feeders and 166 substation transformers according to the grid hierarchy data[2] that PNM provided to the DSA team. In the first half of 2025, solar resources in PNM's territory generated 570 GWh of electricity, with 58% coming from behind-the-meter systems and 42% from front-of-the-meter resources. The PNM system is historically summer peaking and had a summer peak of 1,954 MW in 2025. Table 4 shows historical annual peaks and Figure 1 shows a time series of daily peak loads between January 2020 and August 2025. Average daily temperatures in Albuquerque are shown in the background of the figure. The daily peak MW shows a strong relationship with average daily temperature. Over the past six years, 2023 recorded the highest peak at 2,000 MW. Peak demand increased steadily from 2020 through 2023, followed by a slight dip in 2024 and a subsequent uptick in 2025.

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[2] Due to data availability the analysis included 503 feeders and 165 substation transformers. As reflected in subsequent report tables.

Table 4: Historical Annual Peaks

Year	Peak MW
2020	1,861
2021	1,854
2022	1,962
2023	2,000
2024	1,939
2025	1,954

Figure 1: Time Series of Daily Peak MW

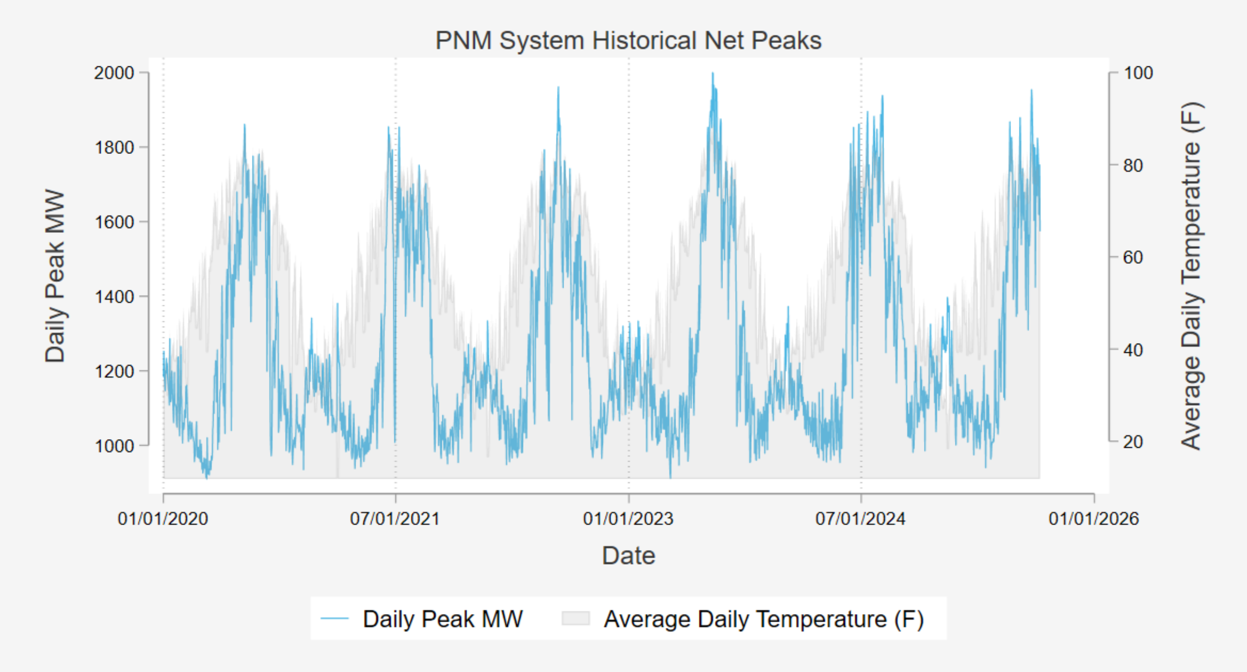

Figure 2 shows a 20-year peak forecast based on PNM's 2026 IRP. The system-level forecasted peak was converted to the transmission and distribution level by applying a 4.7% line loss factor reflecting demand losses during peak conditions[3]. The PNM system is summer-peaking and all forecasted peaks over the 20-year horizon occur in July. The forecast shows rapid peak growth through 2029, followed by a more gradual, steady increase thereafter.

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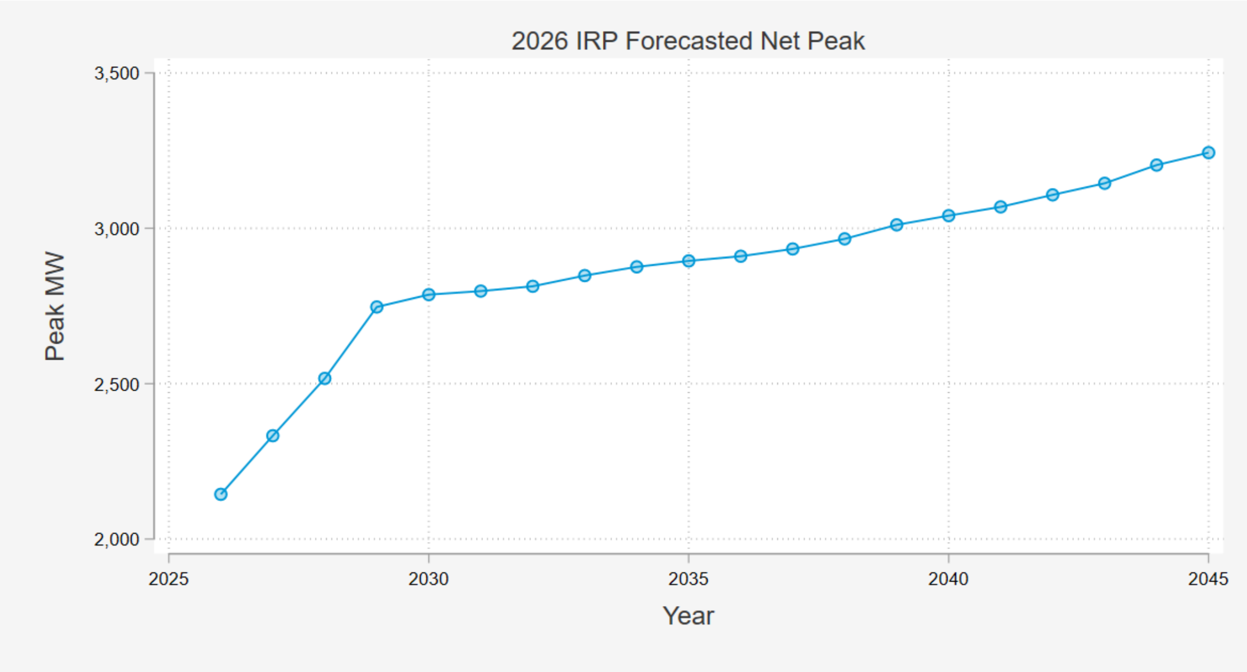
[3] PNM Transmission Planning

Figure 2: Peak Load Forecast



1.2.2 CURRENT PLANNING PROCESSES

In June 2025, the DSA team met with PNM transmission and distribution planning teams to gather information on their current T&D planning processes. The key topic was to learn details on PNM's process such as their planning time horizon, distribution levels for planning, weather normalization, and location-specific growth rates. The meetings were intended to help the DSA team customize the data request and methods to fit the data available. Table 5 summarizes the key findings for each topic.

Table 5: Transmission & Distribution Current Planning Processes Summary

Topic	Key Finding
Supervisory Control and Data Acquisition (SCADA) coverage and availability of hourly or sub-hourly power readings by asset category	▪ 99% coverage of distribution substation transformer at a 15-min level across the past 5 years ▪ 99% coverage of distribution circuit feeder at a 15-min level across the past 5 years
Planning horizon and build lead time, or how far in the future PNM planners consider in their planning activities and how long development and	▪ Transmission zones: ○ 10-year is typical planning horizon ○ 2-5 years is typical build lead time ▪ Distribution substation transformers and circuit feeders: ○ Planning horizon is typically 10 years ○ Build lead time is typically 2-5 years

Topic	Key Finding
construction takes for new assets	
Share of investments driven by load growth	▪ Transmission zones: ○ 24% of investments were driven by load growth ▪ Distribution substation transformers and circuit feeders: ○ 37% of investments were driven by load growth
Weather conditions and planning scenarios	▪ Transmission zones: ○ Weather conditions: transmission planning uses coincident peak forecasts for substation transformers developed by distribution planning. These forecasts reflect recent loads and are not weather normalized. ○ Planning scenarios: PNM applies both N-1 and N-2 criteria across all transmission areas. Normal ratings and long-term emergency ratings are used for planning purposes. PNM does not currently allow operation above equipment ratings during emergencies. ▪ Distribution substation transformers and circuit feeders: ○ Weather conditions: PNM does not routinely weather-normalize historical loads or explicitly apply weather adjustments in planning. However, extreme conditions are considered on a case-by-case basis. 1-in-2 (50:50) weather conditions reflect the hot and cold weather extremes that the PNM territory would expect to occur once every two years. 1-in-10 (90:10) weather conditions reflect the hot and cold weather extremes that the PNM territory would expect to occur once every ten years. Peak loads are higher under 1-in-10 weather conditions. ○ Planning scenarios: PNM considers multiple criteria and equipment limitations in distribution planning, including thermal ratings, design criteria, equipment ratings (CTs, relay settings, substation transformer limits, switches, reclosers, and fuses), thermal limits of conductors, and distances between feeders. PNM's risk tolerance allows emergency ratings for conductors for up to 2 hours, and substation transformers may be operated at emergency ratings for up to 4 hours.
Load forecasts	▪ Forecasts are annual peak forecasts meaning the PNM forecast the magnitude of the peak hour but do not produce forecasts for all hours in the year (not an 8760 forecast) ▪ Feeder-specific growth rates are forecast without incremental DERs. Growth rates are for the peak hour of the substation transformer and feeder. ▪ PNM does not currently perform probabilistic forecasts.

1.2.3 HISTORIC AND PROJECTED T&D SPENDING

To better understand PNM's typical transmission and distribution investments, the DSA team requested historic and projected capital expenditure data in Fall 2025. Historical expenditures analyzed span from 2020 to 2025 and projected expenditures span from 2025 to 2030.

Figure 3 and Figure 4 show the historical and projected spend by investment reasons. In the historical period, investments were primarily associated with system expansion and reliability needs. Projects are often driven by multiple reasons. A substation transformer upgrade might be classified as motivated by reliability, but the project also replaces aging infrastructure near the end of its useful life and allows the area to accommodate new or growing loads due to the increased capacity of the new equipment. Across the projected period, aging or failed equipment and new loads are the most common drivers of investment. In contrast, the need to interconnect new generation is the primary reason for planned investment, which typically cannot be avoided by managing loads.

Total historical capital investment across the PNM service territory was approximately $1.8 billion for distribution and $1.2 billion for transmission. Of each, roughly $450 million in spend was driven by new loads. Over the next five years, projected capital investments are approximately $1.1 billion for distribution and $1.2 billion for transmission. Of each, $330 million in spend is expected to be driven by new loads. Fluctuations in spend are driven by investments needed to support reliability, new technology, and new generation. Investments to support new loads are relatively stable.

Figure 3: 2020-2025 Historical Spend by Investment Reason

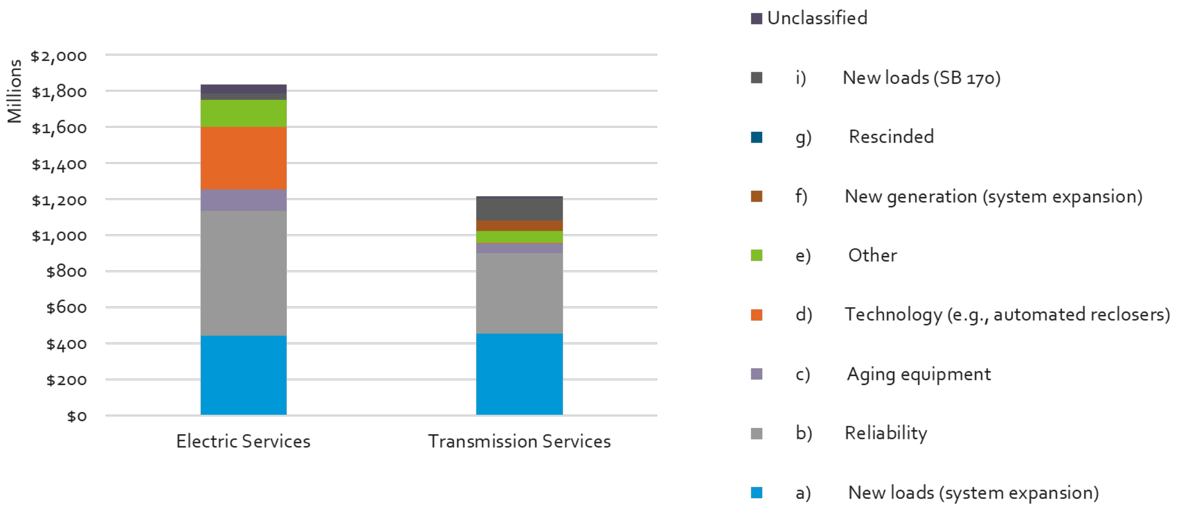
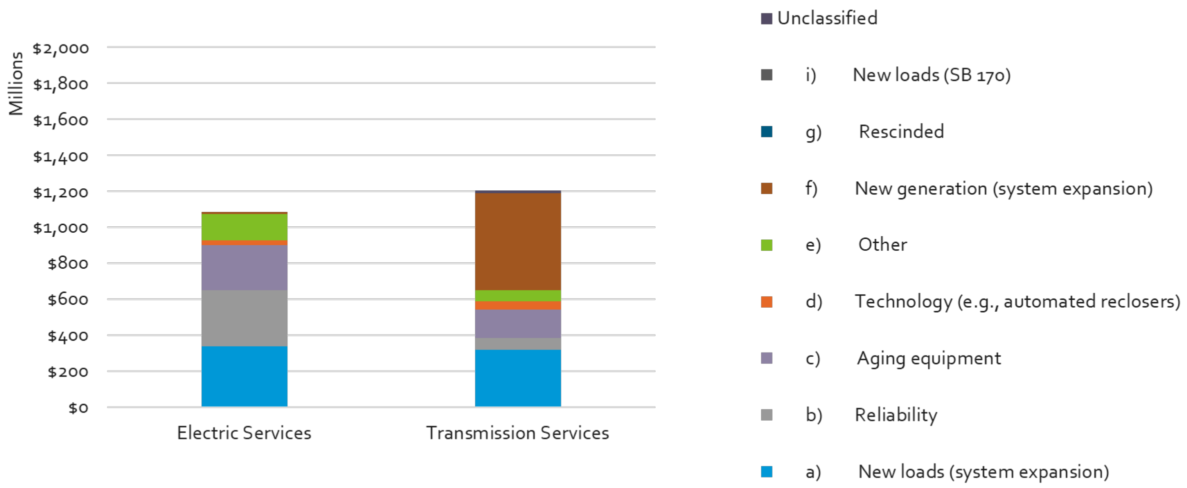


Figure 4: 2025-2030 Projected Spend by Investment Reason



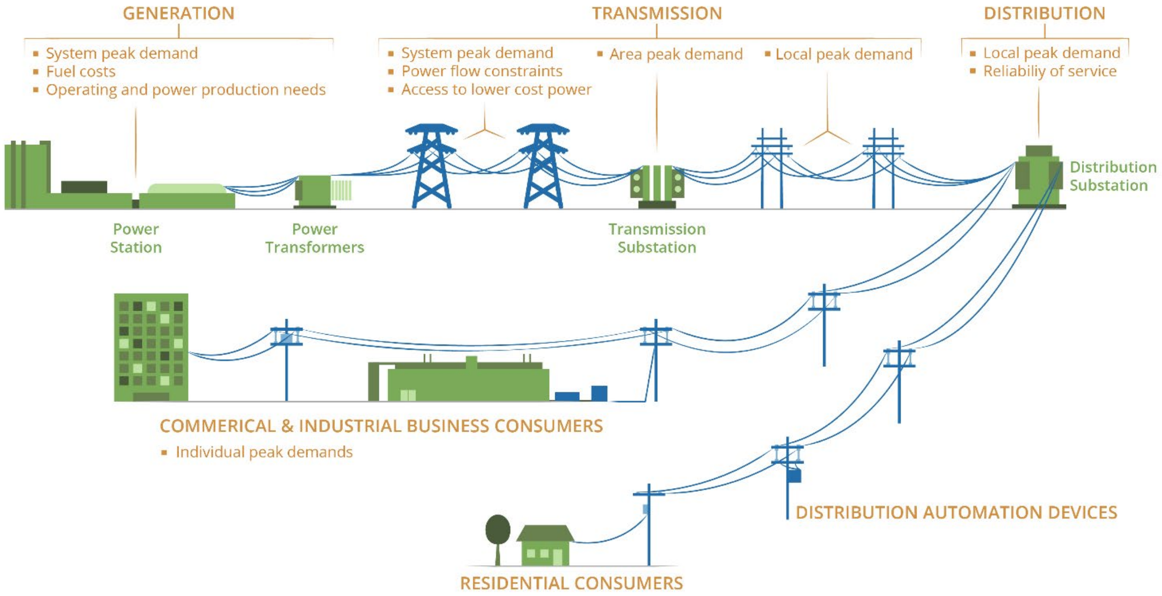
1.3 ELECTRIC GRID HIERARCHY

The electric grid is designed to deliver power from where it is generated to where it is consumed by commercial, industrial, and residential consumers. As power travels from generation to transmission to distribution, it passes through several levels of a hierarchy that adjusts voltage and ensures reliable flow to every site, building, and end use that demands power. The levels of this hierarchy include:

- **Transmission zones**, the broadest level and highest voltage. Utilities are typically split into large geographical regions called transmission zones to organize and coordinate the transfer of power long distances from its generation source to smaller area substations.
- **Bulk substations** (also known as area substations or transmission substations), which control the power flow of an area smaller than a transmission area but larger than a standard substation.
- **Substations** (also known as distribution substations), which control power flow for a smaller local area. Substations are physical locations usually made up of several terminals and several transformers.
- **Terminals**, which are typically located at substations and control power flow to one or more feeder circuits.
- **Transformers**, which are typically located at substations and lower voltage prior to dissemination of power to one or more feeder circuits.
- **Circuit feeders**, which are the smallest unit of analysis, and which provide power directly to wires that serve homes and businesses.

Figure 5 shows a simplified schematic of the electric grid from power plant to consumer.

Figure 5: Electric Grid Diagram



1.4 REPORT ORGANIZATION

The remainder of this report is organized into the following sections.

- Section 2 provides an overview of the methodology.
- Section 3 summarizes study results.
- Section 4 summarizes the key conclusions and recommendations.

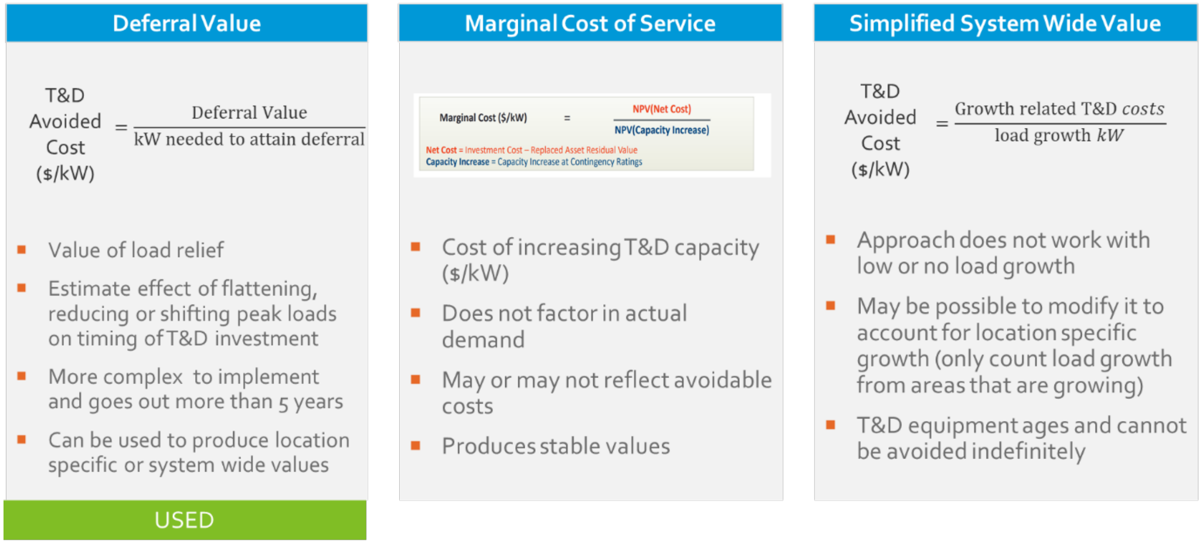
2 METHODOLOGY

This section details the data sources used, lays out the modeling procedure, and explains how avoidable transmission and distribution costs were estimated. Notably, the methodology used represents a departure from the current planning practices in use by PNM. As such, differences are to be expected in the overloads and projects identified by this study relative to the overloads and projects identified by the current planning process. The focus of this study is to quantify deferrable transmission and distribution costs, not to directly inform planning for future transmission and distribution investments. The locational analysis in this study is not a substitute for and is superseded by the granular engineering analysis required for transmission and distribution planning.

2.1 SELECTION OF METHODS

A fundamental decision for the study was the T&D avoided cost paradigm. There are three general approaches used for T&D avoided costs, described below. The approaches and initial recommendations were presented to PNM planning teams for feedback at the project start. The DSA team recommended the deferral value approach for both distribution and transmission.

Figure 6: T&D Avoided Costs Methods Considered



Deferral Value

$$\text{T\&D Avoided Cost (\$/kW)} = \frac{\text{Deferral Value}}{\text{kW needed to attain deferral}}$$

- Value of load relief
- Estimate effect of flattening, reducing or shifting peak loads on timing of T&D investment
- More complex to implement and goes out more than 5 years
- Can be used to produce location specific or system wide values

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Marginal Cost of Service

$$\text{Marginal Cost (\$/kW)} = \frac{\text{NPV(Net Cost)}}{\text{NPV(Capacity Increase)}}$$

Net Cost = Investment Cost – Replaced Asset Residual Value
Capacity Increase = Capacity Increase at Contingency Ratings

- Cost of increasing T&D capacity ($/kW)
- Does not factor in actual demand
- May or may not reflect avoidable costs
- Produces stable values

Simplified System Wide Value

$$\text{T\&D Avoided Cost (\$/kW)} = \frac{\text{Growth related T\&D } costs}{\text{load growth } kW}$$

- Approach does not work with low or no load growth
- May be possible to modify it to account for location specific growth (only count load growth from areas that are growing)
- T&D equipment ages and cannot be avoided indefinitely

The simplified system-wide value approach involves classifying T&D investments as growth-related or not and dividing the cost of the growth-related projects by the system-wide load growth.[4] However, the approach does not work when utilities experience flat or declining loads at a territory wide level.

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[4] For a more detailed discussion on this approach see: Synapse Energy Economics (2021). Avoided Energy Supply Components in New England 2021 Report. Available at https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

The T&D deferral value approach focuses on quantifying the value of load relief on ratepayer costs (i.e., revenue requirements).[5] It effectively compares revenue requirements with and without load relief. While infrastructure upgrades can be temporarily avoided or deferred via load relief, they cannot be avoided indefinitely because some areas are high growth areas that will eventually need new infrastructure or equipment eventually ages and needs to be replaced.

The marginal cost of service study approach was initially used for rates and has since been applied to more granular components. It does not directly account for the T&D savings due to load relief. Rather, it quantifies the supply cost of additional distribution or transmission capacity on the system. At the simplest level, it involves cataloging the costs of various infrastructure investment and dividing the costs of those investments by the incremental transmission or distribution capacity added. The approach uses the cost of adding additional transmission capacity to the system as a proxy for the cost avoided by reducing peak demand.

A second critical decision was to use probabilistic methods to quantify the distribution avoided costs. No one knows in advance precisely how loads will grow or when peaking loads will violate planning standards, nor by how much. Linear forecasts, however, assume precise knowledge. In practice, growth trajectories are rarely linear, and growth follows cyclical patterns. Figure 7 contrasts a linear forecast against two simulated potential growth trajectories, all using the same 1.0% growth rate, with an autocorrelation and a random component. The linear forecast indicates loads will exceed the design rating in 15 years. Loads could exceed the design and risk tolerance far earlier, as shown by Path 1, or never at all, as shown by Path 2. A probabilistic forecast captures and incorporates this uncertainty.

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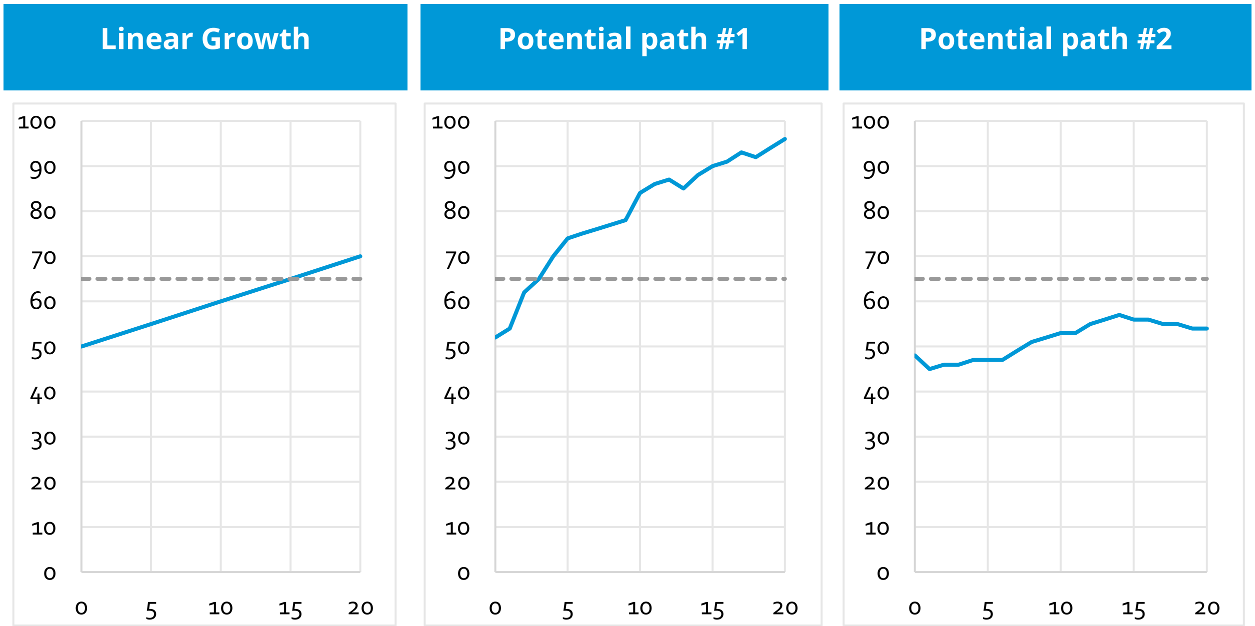
[5] The approach was introduced in the early 1990s as part of an initial wave of T&D deferral projects. Orans, R., Feinstein, C., et. al. (1993) Distributed Utility Valuation Study, submitted to the Electric Power Research Institute, the National Renewable Energy Laboratory, and PG&E.

Figure 7: Comparison of Linear Forecast and Potential Growth Patterns



Furthermore, forecasts are inherently uncertain and become more uncertain over time. Probabilistic methods reflect the reality that infrastructure investments could be triggered earlier or later than linear forecasts. The probabilistic method relies on a Monte Carlo simulation of load growth. For each simulation run, the DSA team assessed if the operating limits were exceeded and, if so, when. In addition, the DSA team assessed how much load relief can defer the upgrades, and the value of load relief. Thus, the expected T&D avoided costs are the average of potential load growth trajectories and the likelihood of loads that exceed operating limits. The values were developed for each distribution component and the system-wide distribution avoided costs are a load weighted average of more granular, location-specific values.

2.2 DATA SOURCES

The study relied on the following main data sources:

1) 15-min SCADA data by feeder and substation transformer from mid-2020 to mid-2025
2) Historical peaks and equipment ratings
3) Hierarchy of feeders, substations transformers, division, zone, and region
4) Hourly weather data for 2005-2025
5) Shape files for each location
6) Queue economic development and community solar
7) Historical front-the-meter (FTM) and behind-the-meter (BTM) PV capacity
8) Historical FTM and BTM generation profile
9) Billing data from July 2020 to June 2025
10) Residential electric vehicle (EV) load shapes
11) WHEV customer charging and rebate data

12) Energy Efficiency load shapes
13) Forecasted achievable potential savings for various EE measures
14) 2026 IRP hourly forecast
15) Capital costs for deferrable projects
16) Financial information (revenue requirement multiplier, fixed charge rate, etc.)
17) Discount rate, inflation rate, book life[6]

Except for weather data and Energy Efficiency load shape (items 4 and 12), all the data above was supplied by PNM. A few points are noteworthy.

- The quantity and time span of SCADA data varied based on data availability.
- EE load shapes were pulled from NREL End Use Load Profiles[7] which provides annual load shapes for common residential and non-residential end uses and building types, aggregated to the census tract level. Common end uses in the aggregated end use profiles include heating, cooling, ventilation, and lighting for a variety of residential and non-residential building types, which were averaged to create composite load shapes. Substations within the PNM territory were mapped to their corresponding census tract to produce a normalized EE load shape unique to each substation.
- All figures and charts reflect prevailing time (MST and MDT).

2.3 KEY ANALYSIS STEPS

Figure 8 describes the main steps in cleaning SCADA data and developing location-specific avoided T&D costs using probabilistic methods. Key elements of the approach include:

- **Use of a probabilistic approach**: Simulating 500 growth trajectories and conducting the entire valuation analysis for each trajectory produces a deferral value estimate incorporating overload likelihood (unlike a deterministic approach).
- **Granular analyses**: Both growth and available capacity vary by location. When assessing the potential value of deferring an investment at a specific location, it is critical to conduct the accompanying analysis at that location. Average system wide growth rates mask the variation detectable at a more granular level and cannot be used to identify and quantify locational deferral opportunities.
- **Quantify deferral value by comparing peak loads and costs, both with and without incremental demand reductions**: The locational value signals when and where demand reductions will be most beneficial and provides a way for EE programs to monetize the value.

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[6] The book life of an asset guides the financial depreciation calculation and determines the number of years over which the utility adds cost to the rate base to recover its upfront equipment and construction costs. The book life is distinct from the useful life, which is the expected mechanical lifetime of the equipment. Book life is typically shorter than the useful life for a given component.
[7] https://www.nrel.gov/buildings/end-use-load-profiles

Incremental reductions in peak demand can change the timing of capital infrastructure upgrades and modify when revenue requirements are introduced into electric delivery rates. The value is simply the reduction in costs when incremental peak demand reductions are added.

- **Time-differentiate the value**: Particularly critical for assessing the extent to which peak demand reductions provide relief is to determine: when, for how long, and how much load relief is needed.

The process was implemented for each feeder and substation transformer. The 500 simulations of potential growth trajectories are critical to estimating the distribution deferral value of managing peak loads.

Figure 8: Key Steps in Estimating Location Specific Avoided Costs

1. CLEAN AND ANALYZE HISTORICAL DATA

- Identify load transfers
- Remove outages and meter recording issues
- Avoid mixing data issues such as load transfers with load growth/declines

2. ANALYZE HISTORICAL DATA

- Plot top 10 peak load days
- Plot load duration curves
- Sensitivity of loads to weather

3. ESTIMATE LOCATION SPECIFIC GROWTH RATES

- Goal is to produce location specific peak growth rates absent incremental load modifiers
- Add back historical solar production
- Use model to predict loads under planning conditions (normal weather years)

4. SIMULATE LOAD GROWTH TRAJECTORIES

- Use Monte Carlo simulation to reflect greater uncertainty in future years
- Factor in growth trend, uncertainty, and auto-correlation (random-walk)
- Forecasts do not include beneficial load modifiers that have not yet been built (otherwise undervalued

5. ESTIMATE THE LIKELIHOOD OF OVERLOADS

- Estimate the likelihood of overloads given current loading, uncertainty in growth and weather
- Identify the subset that are potentially deferable

6. GATHER COST DATA FOR LOCATIONS WITH OVERLOAD RISK

- For locations with an overload risk, gather data on: T&D solution, capital costs, O&M costs, fixed charge rates, useful life and book life, and deferral limits

7. ESTIMATE VALUE OF INCREMENTAL RESOURCES

- For each simulated trajectory, identify if an upgrade is needed, when it is needed, the magnitude of resource required, the deferral period, and the costs with and without deferral

8. PRODUCE 10-YEAR LEVELIZED VALUE AND SYSTEM VALUE

- Expected deferral value by year and location ($/kVA-year)
- Calculate 10-year levelized value
- For system value, calculate the load-weighted value

9. TIME-DIFFERENTIATE VALUE

- Allocate value by hour of day based on the load relief need

The following sub-sections provide greater details about key steps outlined in Figure 8.

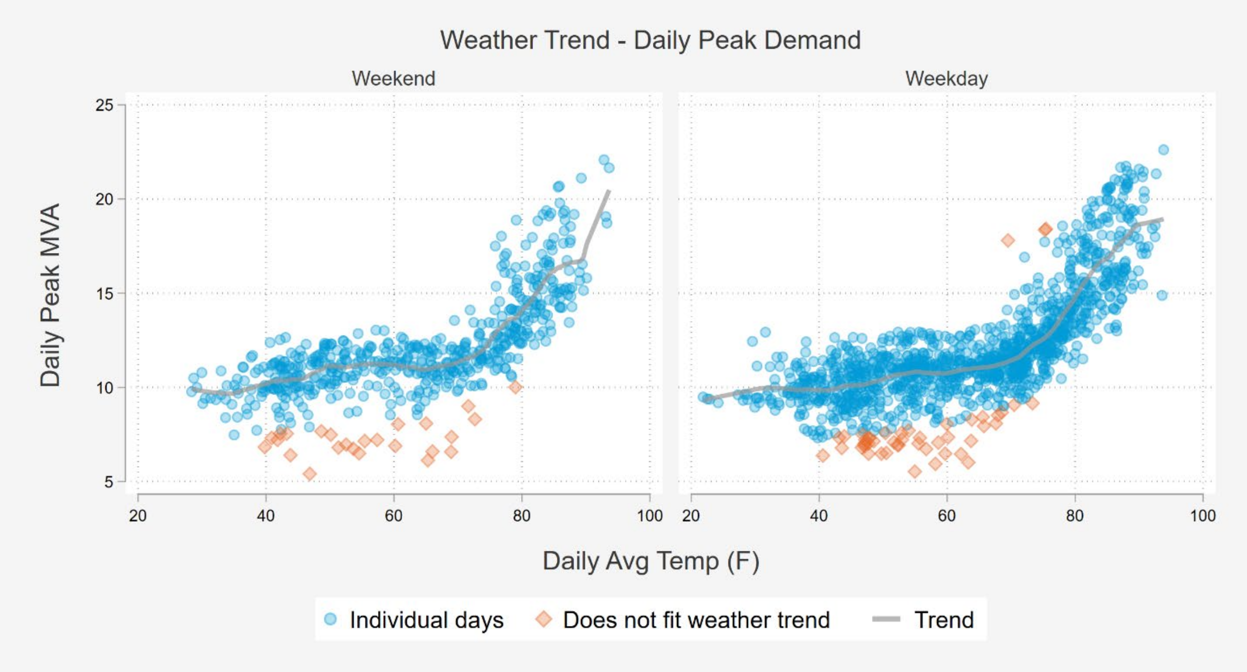
2.3.1 CLEAN AND FILL DATA

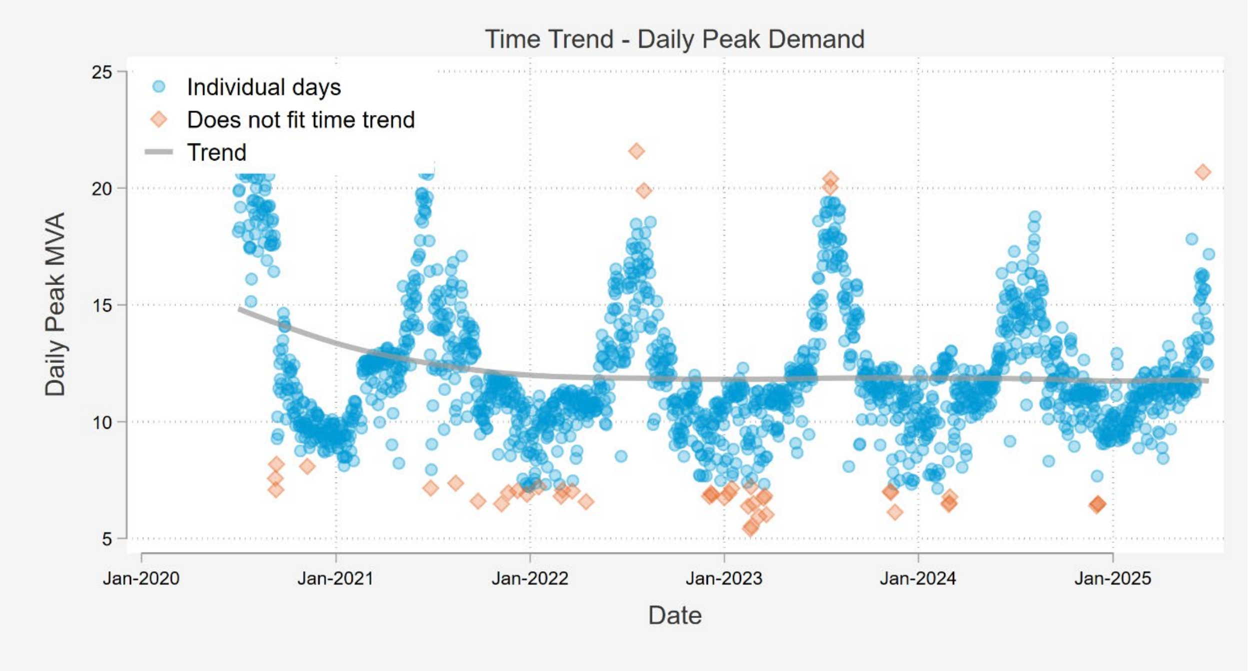
The DSA team aggregated the 15-minute SCADA data to an hourly level and added back FTM solar generation to capture native load. To address missing or invalid historical solar production data, the DSA team estimated hourly production for each site by regressing normalized solar output on sky conditions and month.

One of the key challenges in estimating electric demand patterns and growth at granular locations is the quality of data. It is important to identify and remove outages, data gaps, and other data recording errors to calculate growth rates that are unrelated to temporary load transfers or outages. The DSA team developed algorithms to identify loads with irregular patterns, load transfers, data gaps, and outages from substation transformer and feeder level data. Given the high correlation between loads within the same zone, load patterns from substation transformers or feeders in the same zone were used to fill in anomalous data. For a given location, the DSA team developed a regression equation relating the load at that location to the load at surrounding areas as well as day of week, month, and outdoor temperature.

Figure 9 illustrates an example of a location with anomalous data reads, which, unless detected, can be mistaken for a change in load and distort the sensitivity of the area's loads to weather.

Figure 9: Example of Data Cleaning



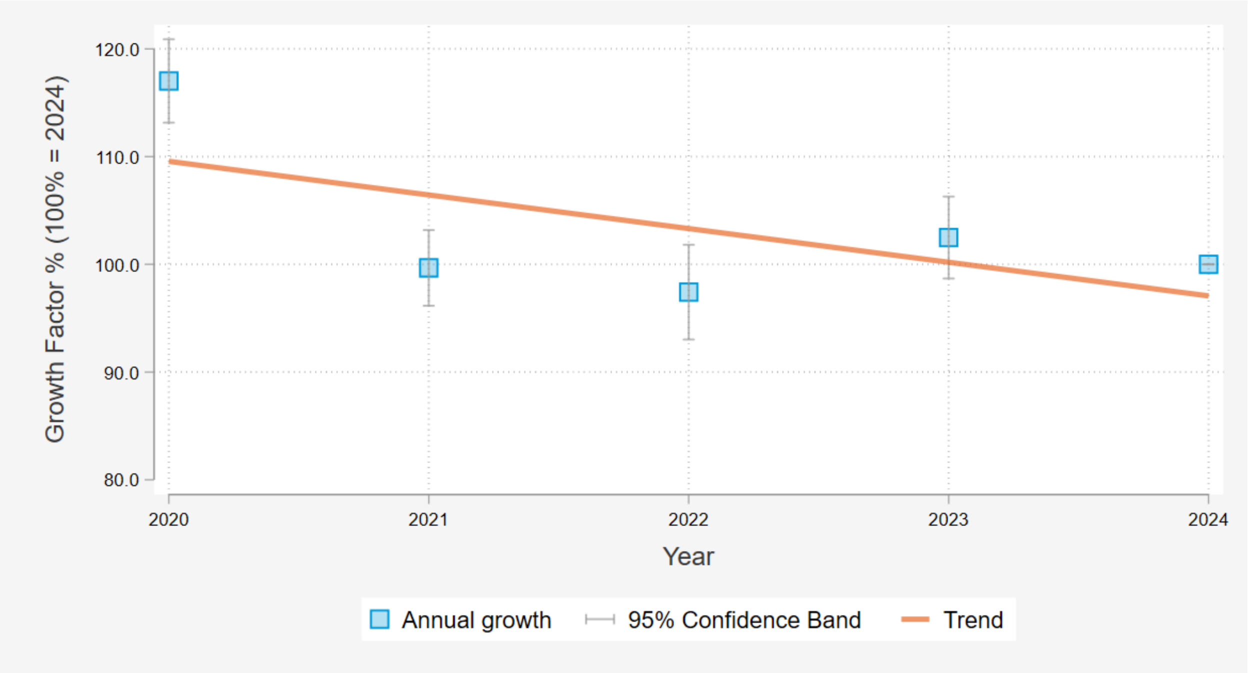


2.3.2 ESTIMATE HISTORICAL LOAD GROWTH

The objective of this step was to estimate historical load growth for each year in the analysis period in percentage terms. The available SCADA dataset spans mid-2020 through mid-2025 and does not include the 2025 summer peak period (June–August). To make full use of the available data and ensure that each year's peak was captured, the DSA team defined an "analysis year" as June through May rather than using a calendar year. The year-to-year (2020-2024 analysis years) growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth each year was related to growth during the prior year— technically known as autocorrelation. The econometric models were purposefully designed to estimate gross historical load growth. The econometric models also allow us to weather normalize loads for 1-in-2 and 1-in-10 weather peaking conditions. The gross load growth accounts for native growth. By doing this, the DSA team added back historical BTM solar production based on location specific installed resources over time.

Figure 10 illustrates some of the key outcomes from this analysis. First, the analysis produces year-by year estimates of the historical growth or decline in loads after controlling for differences in weather, day of week, and season. Second, the year-by-year estimates allowed the DSA team to estimate the growth trend. In the example below, loads are declining at a rate of 0.3% per year. Third, the results enabled the DSA team to estimate the variability in year-to-year growth patterns (also known as the standard error of the forecast).

Figure 10: Year-by-year Estimates of Historical Growth (Single Substation Transformer Example)



2.3.3 SIMULATE LOAD GROWTH TRAJECTORIES

The native load growth forecasts were developed using probabilistic methods that produced the range of possible load growth outcomes by year. It simulates the reality that the near-term forecast has less uncertainty than forecasts ten years out. The DSA team implemented a total of 500 growth simulations for each feeder and substation transformer. Each simulation produced a distinct growth trajectory that considered the historical trend, variability in growth patterns, and the fact that growth patterns are autocorrelated.

The native growth rate simulations are based on historical growth patterns and a random component based on econometric modeling. As shown in Equation 1, each forecast year's growth is a combination of an independent growth component and the prior year's growth trajectory.

Equation 1: Annual Growth Calculation

$$Annual\ growth_t = Independent\ growth_t * (1 - autocorrelation) + Annual\ growth_{t-1} * autocorrelation$$

The independent growth component is based on a random draw that factors in the historical trend, the uncertainty around the trend, and the year-to-year variation at the location. The forecasts are cumulative, meaning that each simulation's forecast trajectory builds on the prior year, producing a path. The process was repeated 500 times for each feeder and for each substation transformers. The result is a full picture of the possible load growth outcomes by year. Each of the 500 simulated growth trajectories produces specific information about if, and when, the design rating would be exceeded, as well as the amount and timing of peak demand reduction required to maintain loads below the design ratings.

Figure 11 illustrates probabilistic forecasts. This type of forecasting requires estimating historical load growth patterns and simulating potential load growth trajectories repeatedly. The result of the repeated simulation is a distribution of outcomes. Some outcomes are far more likely than others. Figure 12 shows how this distribution of outcomes can be summarized in specific confidence bands.

Figure 11: Illustration of Location Specific Simulations and Probabilistic Forecasts

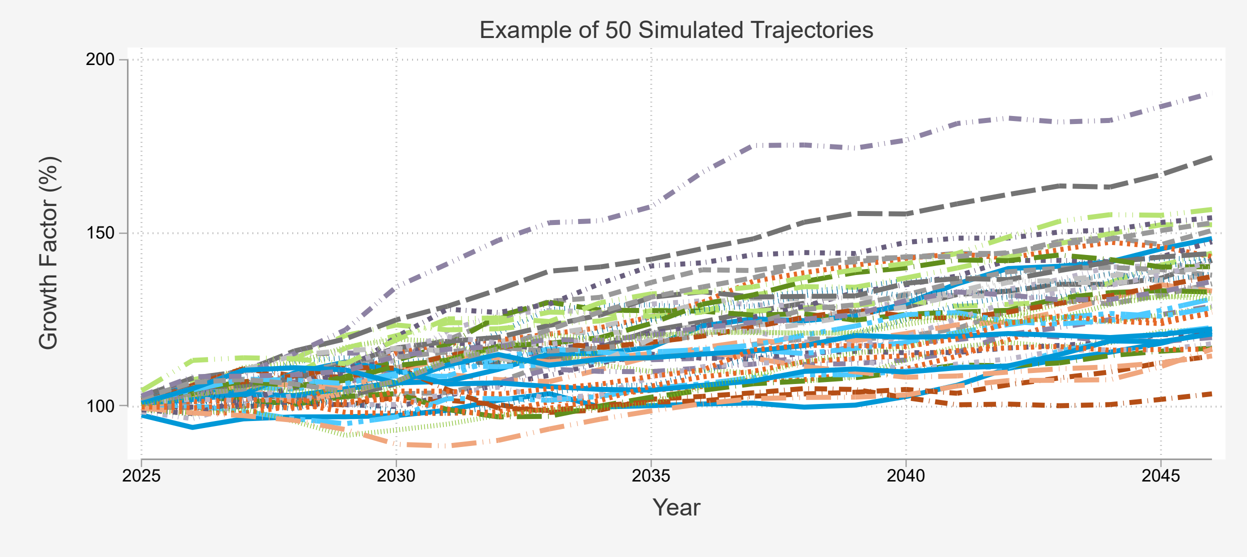
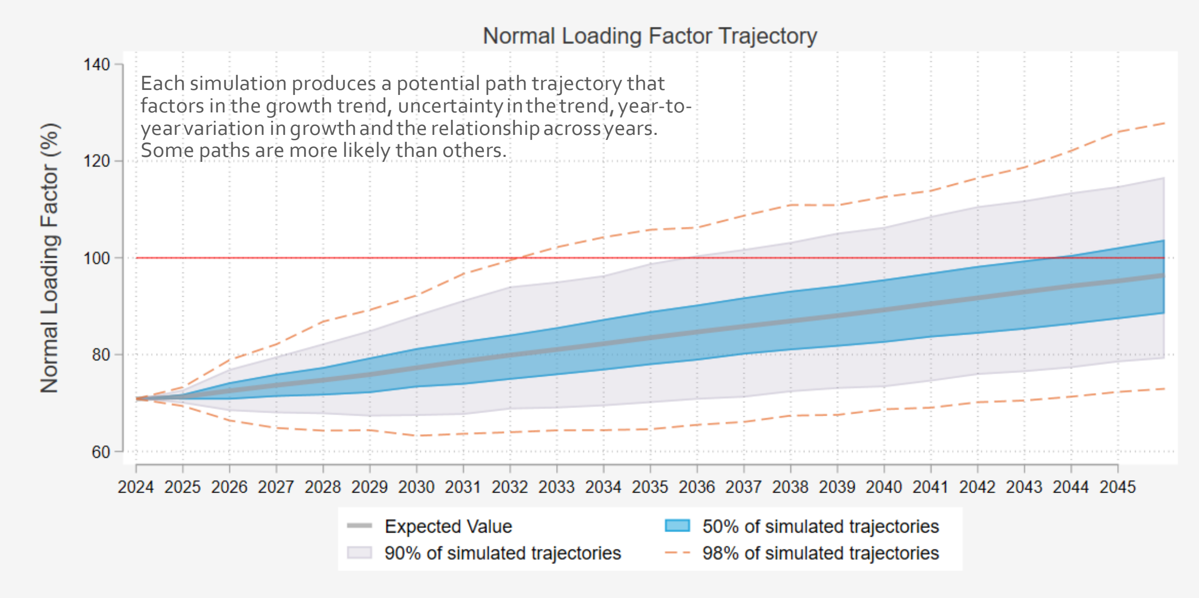


Figure 12: Annual Peak Forecast Confidence Bands

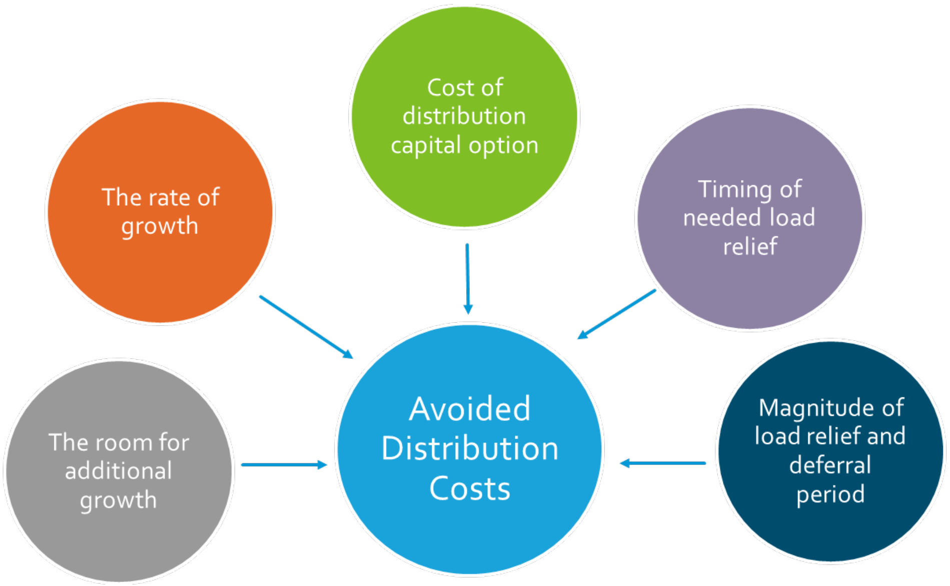


Each simulation produces a potential path trajectory that factors in the growth trend, uncertainty in the trend, year-to-year variation in growth and the relationship across years. Some paths are more likely than others.

2.3.4 ESTIMATE COSTS WITH AND WITHOUT DEFERRAL

Figure 13 summarizes the five factors the DSA team considered when calculating distribution deferral value. These factors are key to identifying the magnitude of reductions at the right location at the right time and right season to delay upgrades. The calculation was implemented for each feeder and substation transformer that had a valid growth rate and operating limit. Next, the DSA team layered the two levels (feeder plus substation transformer) to get the total distribution avoided cost for each site. For system-wide values, the estimates consider the likelihood that reductions would be in locations with value due to random chance. The DSA team emphasizes that system-wide value is a load-weighted average of areas where reductions do lead to deferral of distribution investments.

Figure 13: Several Factors Affect Avoided Distribution Value



The estimated avoided distribution costs are based on the load forecast and the outcome of each simulation run. The process involved applying the four steps below to each of the 500 simulation runs for each location:

1. **Identify the timing of the upgrade for each simulation run, location, and year.** For each location, each simulation run produced a potential growth trajectory, which either exceeded the design rating or remained below it.

2. **Identify the magnitude of demand reduction needed to maintain loads below the design rating.** Once peak demand reductions were determined, the DSA team simulated demand reductions equal to the projected overload amount. Once introduced, the peak demand reductions were assumed to remain in place for the maximum deferral period (10 years) or until peak demand exceeded the operating limit by 20%, whichever came first. This reflects the reality that most projects cannot be postponed indefinitely, and the length of deferral may be shorter in areas with rapid growth.

3. **Model infrastructure costs with and without peak demand reductions for each simulation run, location, and year.** When the design ratings were exceeded, the costs of the infrastructure investments were triggered and allocated based on the revenue requirement of the upgrade. For example, equipment upgrade costs of $8.7 million with a 34-year book life would be spread out, or annualized, over 34 years. This approach replicates how capital costs are incorporated into the rate base. The DSA team implemented the same cost calculations but instead assumed the investment could be deferred for up to the maximum deferral period.

4. **Calculate the avoided costs per kW for each simulation run and location.** If loads were not projected to exceed the respective design rating, no costs are avoided since a growth-related infrastructure investment would not have taken place. If the loads in a particular simulation exceeded the design rating, reducing loads to levels below the design rating would avoid or defer growth related infrastructure investment. Thus, the avoided costs are the difference between the costs with and without the reduction in loads necessary to avoid or defer the upgrade. Distribution deferral value considered the capital costs and the magnitude of the required load reduction. Equation 2 reflects the deferral value calculations for each simulation run and location. In the equation, i reflects the inflation rate, r reflects the discount rate, and Δt reflects the deferral period. In practice, the DSA team implemented the calculations using revenue requirement multipliers[8], based on fixed charge rate[9] and asset booklife[10] assumptions provided by the PNM rates department. The share of capital cost was annualized over the book life with the revenue requirement multiplier.

Equation 2: Total Deferral Value Calculation

$$Total\ Deferral\ Value\left(\frac{\$}{kW}\right)=\frac{Capital\ Cost\ (\$)\ \cdot Revenue\ Requirement\ Multiplier\ \cdot\left(1-\left(\frac{1+i}{1+r}\right)\right)^{\Delta t}}{Load\ Reduction\ Needed\ for\ Deferral\ (kW)}$$

The total deferral value was annualized over the deferral period for each simulation run and location using Equation 3, where r equals the discount rate, i is the inflation rate and n is the number of deferral years:

Equation 3: Annualized Deferral Value Calculation

$$Annualized\ Deferral\ Value=Total\ Deferral\ Value\left(\frac{\$}{kW}\right)\cdot\frac{(r-i)}{(1+r)}\cdot\frac{(1+r)^n}{[(1+r)^n-(1+i)^n}$$

The detailed calculations for each of the 500 simulations at each site were subsequently used to estimate the expected avoided costs per kW at each location for each year. As Equation 4 shows, the

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[8] 1.62 assuming an after tax WACC of 6.90%

[9] 12.21% for transmission investments and 12.46% for distribution investments

[10] 37 years for transmission investments and 34 years for distribution investments

expected avoided cost is calculated by taking the average across all simulation runs (r) for each year (t) at an individual location (i).

Equation 4: Expected Avoided Cost Calculation

$$Expected\ Avoided\ Cost_{i,t} = \frac{\sum_{r=1}^{500} \$ \frac{kW}{year}_{i,t,r}}{500}$$

Because the analysis relied on probabilistic methods, the avoided cost estimates reflect the risk mitigation value of managing loads to remain below the design rating. That is, the probabilistic method assigns avoided costs to locations and years with, for example, a 10% likelihood of an upgrade. A linear forecast would not assign any value to that year.

2.3.5 ALLOCATE AND TIME-DIFFERENTIATE PROJECT DEFERRAL VALUE

Distribution deferral value per kW-year is assigned to each substation transformer and feeder where load relief helps to avoid overloads (locational deferral value). The locational deferral values at each level of the distribution system are aggregated up the hierarchy to form the distribution deferral value. In practice, locational value can only be captured by acquiring load relief (reduction in peak demand) in the locations where deferral value exists. Value can be aggregated to the system level by taking the average value across locations with value. To account for variation in size across locations, value across locations was weighted by the coincident peak contribution of each location.

The time-differentiated value is based on when, for how long, and how much load relief is needed. For example, no amount of summer peak demand reduction will defer an upgrade to a substation with projected overloads in the winter. The normalized peak day load shape for each location was used to allocate value across hours. While relatively shallow load relief needs may only require load reductions in the top one or two hours, deeper load relief needs necessitate shaving load across more hours and results in a less concentrated value as it is spread across more hours.

2.3.6 CALCULATE VALUE OF ENERGY EFFICIENCY

Calculating the value of EE was the final step in the analysis. First, end-use load shapes[11] were weighted based on the expected end-use mix in the EE forecast and combined to produce an EE load shape for each site. The load shape was then normalized by dividing by the maximum annual MW of EE at that location, allowing the DSA team to compare shapes across sites with different EE magnitudes. The normalized EE load shape values were then multiplied by the deferral value to derive the locational value of EE.

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[11] Water heating, space cooling, space heating, ventilation, lighting, other

To aggregate granular values to a system-wide metric, the granular value at each location was weighted by coincidence with the system seasonal peak, which is consistent with the technology-agnostic avoided cost approach.

2.3.7 METHODOLOGY ADJUSTMENTS FOR TRANSMISSION DEFERRAL VALUE

The approach for estimating avoided transmission costs was similar in many ways to the approach for estimating avoided distribution costs. Table 6 compares key methodological elements for distribution and transmission deferral valuation.

Table 6: Comparison of Approaches for Distribution and Transmission Deferral Valuation

Methodological Element	Distribution	Transmission
What type of loads were used for the analysis?	Local peak load forecasts for each feeder and substation transformer from 2026 through 2045.	System coincident peak load forecasts for each substation transformer from 2026 through 2045.
Was the analysis probabilistic?	Yes, avoided costs were estimated for each of 500 growth trajectory simulations for each location.	No, the avoided costs were estimated using expected growth trajectory for each location.
How were overloads modeled?	Overloads on each location for each simulation were defined as projected peak load surpassing the normal rating twice consecutively, or surpassing the emergency rating.	Load flow analysis was performed across substation transformers with load modifiers (planning load) and without load modifiers (valuation load) to identify the limiting element and projected future investments.
How was the deferral period determined?	The deferral period was calculated for each probabilistic forecast run. Deferral was assumed to start when the overloads occurred and remain in place for the maximum deferral period (10 years) or until peak demand exceeded the operating limit by 20%, whichever came first.	The first year of deferral was the projected in-service year under the without load modifiers scenario. The last year of deferral was assumed to be the year before the in-service year under the with load modifiers scenario.
How was deferral value calculated?	Equation 2 was used to calculate total deferral value and Equation 3 to annualize the value. As shown in Equation 4 expected value was the average across simulation runs.	Equation 2 was used to calculate total deferral value and Equation 3 to annualize the value. The analysis was not probabilistic and there was no need to take the expected value.
How was project deferral cost allocated across locations?	No allocation was needed given the locational nature of the analysis.	Load flow calculations were used to proportionally allocate deferral value to substation transformers where load reductions helped alleviate the transmission constraint.

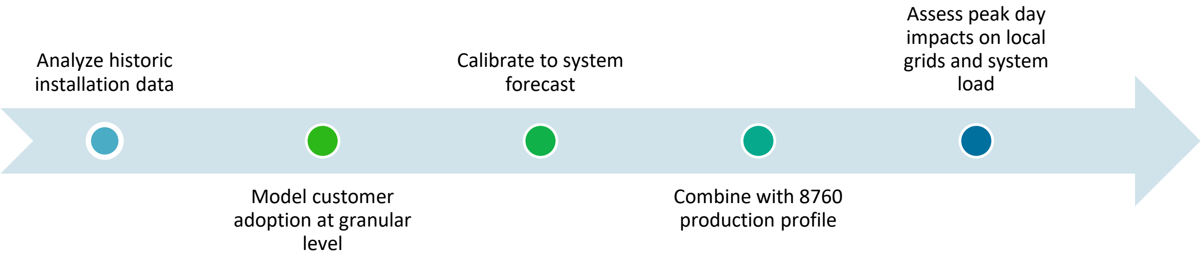
Methodological Element	Distribution	Transmission
What approach was used to quantify the magnitude of load relief required for a deferral?	Within each growth simulation, demand reductions were assumed to equal the projected overload amount.	For substation transformers where load reduction was deemed beneficial, the load relief to achieve deferral was quantified as the difference in projected loads in the final deferral year between the with and without load modifier scenarios.
How was annual deferral value time differentiated by hour and season?	The normalized peak day load shape for each location was used to allocate peaking risk and value across hours.	The system peak day load shape was used to allocate peaking risk and value across hours, by applying a 15% peak hour reduction to avoid concentrating value in a single peak hour and to avoid spreading the value among hours with no real peaking risk.
How was the value of EE calculated?	The value at each location was derated to reflect coincidence with the shape of EE forecast for that location.	The value at each location was derated to reflect coincidence with the shape of EE forecast the system.
How was the system average value calculated?	The system value was weighted by coincidence with the system seasonal peak.	The system value was weighted by coincidence with the system seasonal peak.

2.4 ADJUSTMENTS TO LOAD FORECASTS

Several adjustments were made to load forecasts to account for large load changes in the forecast that are not a part of native load growth. These adjustments come from projected load growth from (1) planned economic development, (2) electric vehicles, (3) existing energy efficiency, (4) behind-the-meter solar, and (5) economic development (lump loads). For community solar (CS), , all CS capacity in the queue was assumed to be built when developing the granular forecast. For economic development projects, which include data centers, warehouses, and public (DCFC/L2) charging stations, an economic development forecast provided by PNM was dispersed among the feeders.

A separate approach was taken for forecasting EVs and behind-the-meter solar, in which propensities were developed at the premise level, and subsequently calibrated to add to the total system-level forecast. Figure 14 provides an overview of the general methodology used for granular forecasting. This methodology is relevant in this study to only EVs and BTM solar.

Figure 14: General Overview of Granular Forecast Methodology



Customer-level usage and property characteristics, such as square footage, market value, and year built, were used to produce propensity scores for each premise in the territory, as these features are often predictive of whether or not a customer will adopt a technology in the future. The propensities were then adjusted for each forecast year so that the total consumption or generation from increased EV or BTM solar adoption equaled the top-down, system-level forecast provided by PNM. Because the system-level forecast was rate class-specific, the calibration process was done at the rate class level as well.

Finally, since there was little data on EE adoption at the premise level, propensity scores for EE were developed by using the gross annual usage of the customer as a proxy propensity. PNM's system-level EE forecast was then spread among the premises according to their usage.

In order to stack the load modifier forecasts on top of the hourly native load growth, the annual consumption and generation forecast produced from the calibration process needed to be converted into an hourly demand forecast. Load shapes for EVs and BTM solar were provided by PNM and applied to the annual forecast to achieve this. For EE, NREL's aggregated end-use load profiles were pulled for the counties that pertained to PNM's territory. These end-use load profiles were narrowed to the end uses relevant to the residential, commercial, and industrial sectors, and a composite load shape of these end uses was created. Weights were applied to each end use when creating the composite load shape, and were derived from the annual share of forecasted achievable potential, which was taken from PNM's potential study.

Table 7 summarizes the primary data sources, the forecasting method, and the load shape source for each of the load modifiers forecasted in this study. More detail on each step of the granular forecasting method can be found in Appendix A – Granular Forecasting Methods.

Table 7: Data Sources and Methods for Load Modifier Forecasting

Load Modifier	Primary Data Sources	Granular Dispersion Method	Load Shape Source
Energy Efficiency	Customer billing data (2020-2025)	Use annual gross usage as a proxy propensity score	NREL
Electric Vehicles	Customer billing data (those on whole-home EV rate)	Propensity model (random forecast classification)	PNM
Economic Development	IRP Economic Development forecast	Disperse IRP Economic Development forecast	IRP
BTM Solar	Customer billing data (monthly generation) Historical PV interconnections (2020-2025) Hourly generation for large solar sites	Propensity model (random forecast classification)	Large solar site hourly generation, de-rated to account for decreased efficiency for smaller customers
Community Solar	CS queue	Assume all queue CS is built	Large solar site hourly generation

The result of the granular forecasting is 20 years of hourly demand for each of the load modifiers. This forecast can be added to the native load forecast to understand how the planning load changes over time, and how the peak hour shifts as load modifiers such as solar and EVs become more prevalent across the territory. Table 8 shows the coincident peak demand by year for the entire system, and shows how the planning and valuation load are developed from the granular forecast. The table specifically shows the annual peaks based on the valuation load, which does not include load relief resources that have not been built and which are uncertain, specifically BTM solar and energy efficiency.

Table 8: Forecasted Peak Coincident Valuation Load, MW (2026-2045)*

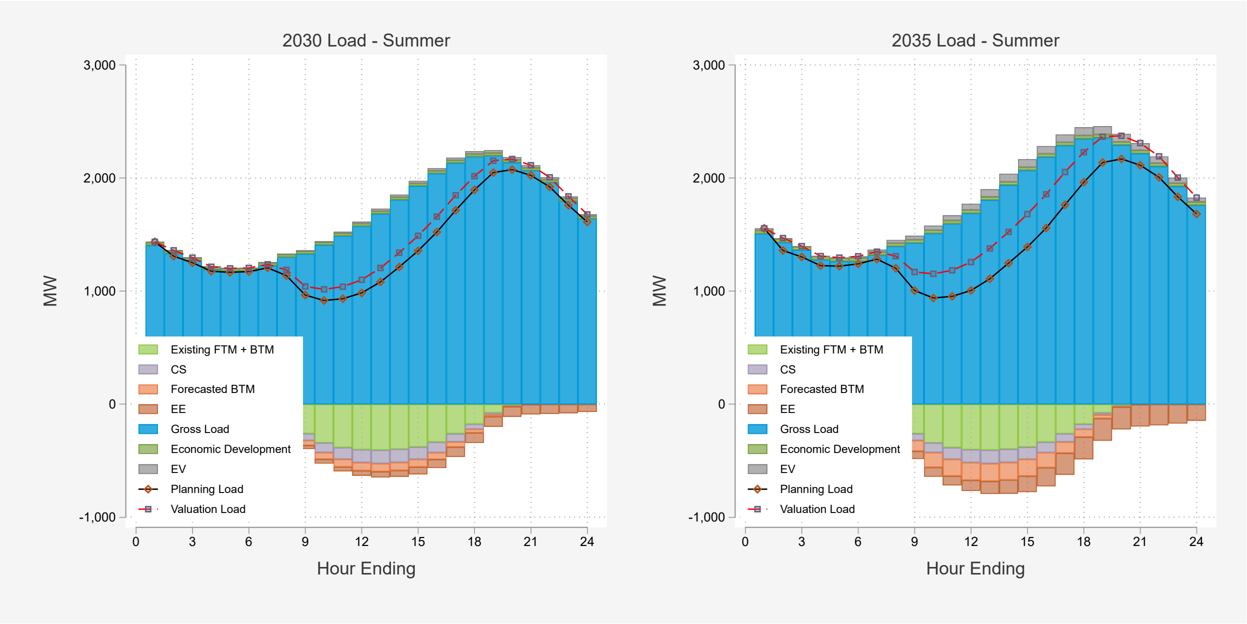
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		
Year	Gross Load Forecast	Economic Development	EE	CS	Existing FTM	Existing BTM	Forecasted BTM	EV	Planning Load (a)+(b)+(c)+(d)+(e)+(f)+(g)+(h)	Valuation Load (a)+(b)+(d)+(e)+(f)+(h)
2026	2014	11	-17	-2	-4	-10	-1	3	1994	2012
2027	2057	15	-34	-3	-4	-10	-1	7	2027	2062
2028	2101	20	-49	-3	-4	-10	-2	13	2065	2117
2029	2118	21	-66	-3	-4	-10	-2	19	2073	2141
2030	2139	23	-91	-3	-4	-10	-3	26	2077	2170
2031	2158	24	-116	-3	-4	-10	-4	33	2079	2199
2032	2211	26	-139	-3	-4	-10	-5	42	2118	2262
2033	2242	27	-160	-3	-4	-10	-5	51	2138	2304
2034	2277	27	-180	-3	-4	-10	-6	61	2162	2348
2035	2294	27	-198	-3	-4	-10	-7	71	2171	2376
2036	2299	27	-215	-3	-4	-10	-7	83	2170	2392
2037	2333	27	-229	-3	-4	-10	-8	94	2200	2437
2038	2349	27	-243	-3	-4	-10	-9	107	2214	2466
2039**	2442	27	-254	-18	-29	-47	-45	130	2206	2505
2040	2480	27	-267	-18	-29	-47	-49	146	2244	2560
2041	2480	27	-279	-18	-29	-47	-52	162	2244	2575
2042	2510	27	-290	-18	-29	-47	-55	178	2276	2621
2043	2544	27	-300	-18	-29	-47	-59	193	2312	2671
2044	2572	27	-309	-18	-29	-47	-63	209	2343	2715
2045	2615	27	-317	-18	-29	-47	-66	224	2390	2774

*Since the study was performed at the distribution level, transmission level loads and load modifiers are excluded from this table and the distribution analysis. Transmission level loads and load modifiers were included in the transmission load flow analysis.

**The system peak day was modeled by summing the bottom up 8760 valuation load forecasts. Beginning in 2039 the peak hour of the 24-hour shape of the system peak day forecast shifted from HE 20 to HE 19, resulting in a modest increase in contribution from solar PV sources.

Once the valuation load is calculated, the peak days for each forecast year based on the valuation load can be determined. Figure 15 shows the summer system coincident peak day for years 2030 and 2035, and shows how the various components of the forecast add to the total planning and valuation load. The planning load in this study is the sum of the gross load and all the load modifiers, regardless if they have been built or not.

Figure 15: Forecasted Planning and Valuation Load on the Summer System Peak Day



3 AVOIDED COST RESULTS

This section of the report provides an overview of the study outputs.

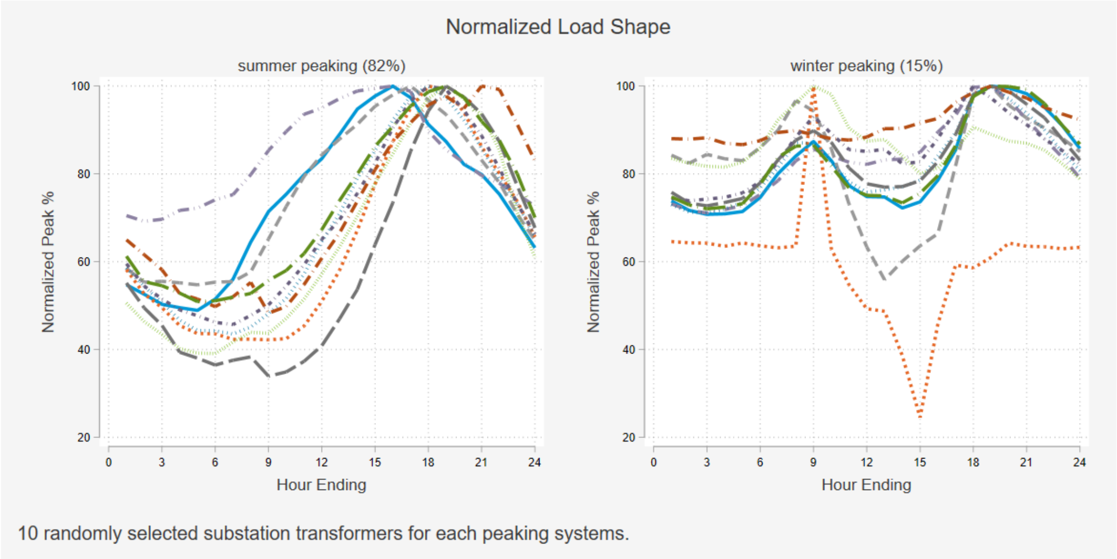
3.1 HISTORIC LOAD PATTERNS

To focus the analysis on assets that need or may need upgrades due to load growth, the DSA team conducted a "loading and growth" analysis. The primary goal of the loading and growth analysis was to understand the magnitude of recent peaks relative to the maximum loads for which those assets are rated. This also provides the growth trend over time of both yearly and seasonal peaks.

A key topic was the kind of components that are the most important in making infrastructure upgrade decisions, e.g., feeders, terminals, transformers, substations, or bulk substations. An additional point was what equipment rating (operating limit) PNM uses to determine loading factor.

When examining historic loads, the DSA team looked both at load shapes on peak days, as well as the concentration of peak loads. Figure 16 illustrates the timing of peak day usage for a sample of PNM's substation transformers. The plot shows the weather normalized hourly loads top peak load day for each individual substation transformer, broken out by whether the substation transformer peaked in summer or winter. The plots were normalized to display the percentage of usage in each hour relative to the peak usage of the day (the highest point of each curve is 100%), allowing comparison of distribution networks of different sizes. Generally, the greatest usage on peak days occurs between 4 PM and 7 PM for locations that peak in summer, and between 7 AM-9 AM and 5 PM-7 PM for locations that peak in winter. Among the 165 substation transformers included in the analysis, 82% were summer-peaking, 13% were winter-peaking, and the remaining 3% peaked during shoulder months.

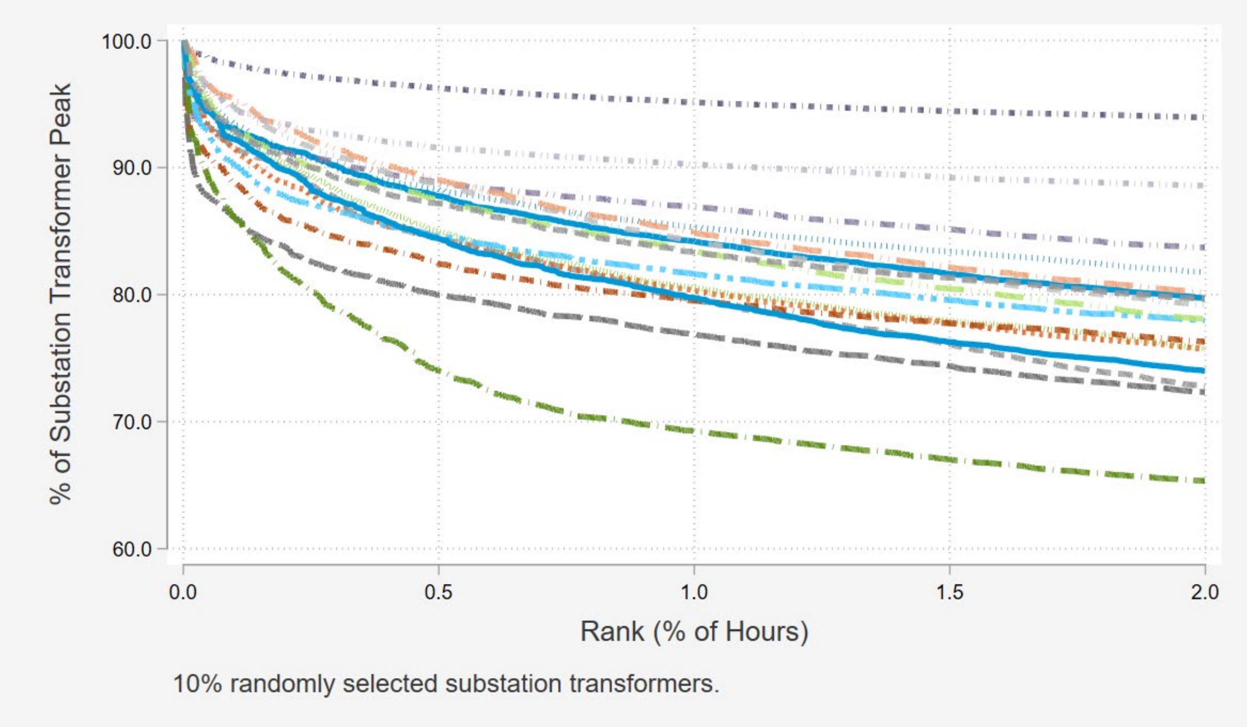
Figure 16: PNM Location Specific Peak Day Load Shapes – Substation Transformer



10 randomly selected substation transformers for each peaking systems.

Figure 17 uses load duration curves to illustrate a fundamental feature of electric load. Load duration curves sort electric demand from highest to lowest and highlight how extreme loading conditions are concentrated in a limited number of time periods. The graphs reflect the load duration curves for PNM's distribution system. The graph shows only the top 2% of 60-minute periods in the analysis period for 10% randomly selected substation transformers. Each load duration curve shows load as a percentage of each substation transformer's largest load, allowing side-by-side comparisons for areas with a different magnitude of demand. For all locations, all loads within 10% of the peak occur in less than 2% of the periods over the analysis period. In some locations, all loads within 20% of the peak occur in less than 1% of the periods. These substation transformers have a higher concentration of peak loads than others. In other words, the highest peak loads occur in only a small fraction of periods for these substations. Substation transformers with these characteristics may be good candidates for dispatchable demand response or NWA projects because a relatively small number of hours need to be targeted to reduce a large portion of the peak load.

Figure 17: PNM Normalized Load Duration Curves – Percent of Peak Load



3.2 LOADING AND GROWTH RATES

Locations with potential infrastructure deferral value are areas where loads are growing and there is limited excess capacity to accommodate the growth. Areas with enough capacity to accommodate growth are less likely to trigger growth-related infrastructure upgrades. Similarly, areas where local peak demands are declining over time are less likely to require growth-related upgrades. Table 9 summarizes the 2025 weather normalized loading factor for substation transformers and feeders in

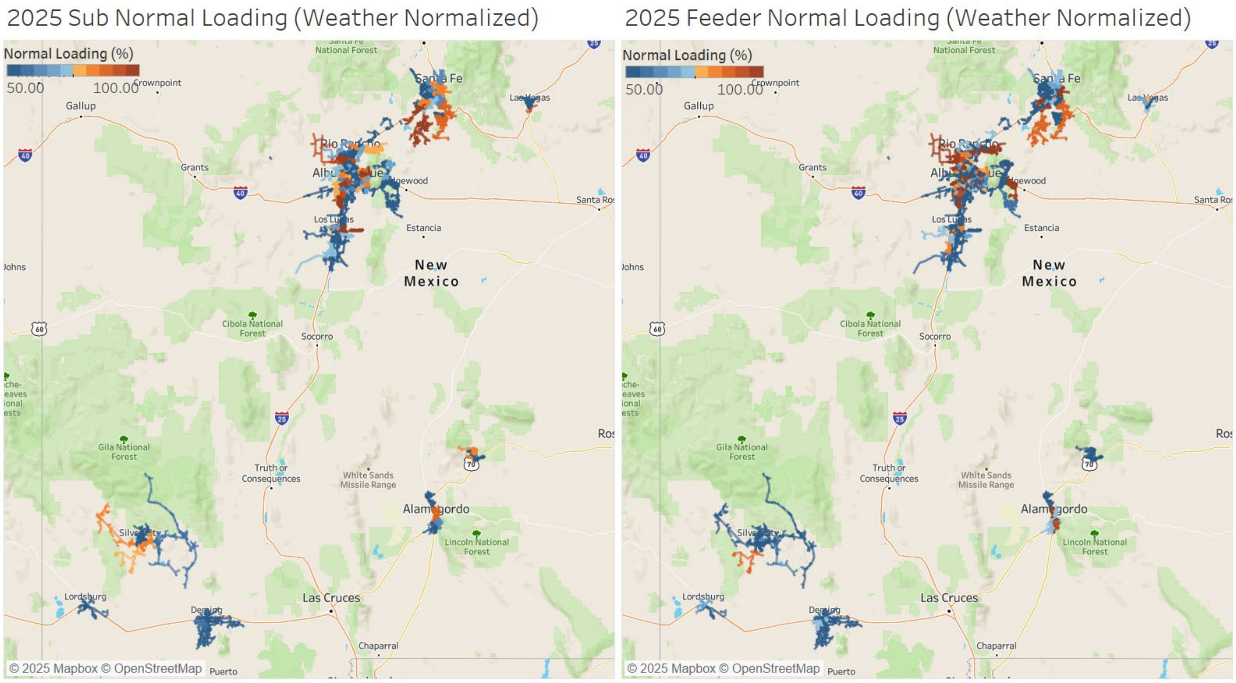
PNM territory. Most are not highly loaded, but a significant number of peaks exceeded operating limits for feeders.

Table 9: Overview of 2025 Weather Normalized Normal Loading Factors

Loading Factor	# of substation transformers	# of feeders
Less than 50%	65	251
50% to 60%	25	63
60% to 70%	26	42
70% to 80%	20	48
80% to 90%	13	31
90% to 100%	9	14
100% or higher	7	54
Total	**165**	**503**

Figure 18 displays the 2025 weather-normalized loading factor and geographical location for feeders and substation transformers in PNM territory. Figure 19 zooms in the three large zones: Albuquerque, Santa Fe, and Sandoval where high loading are concentrated. Darker orange colors indicate higher loading factors.

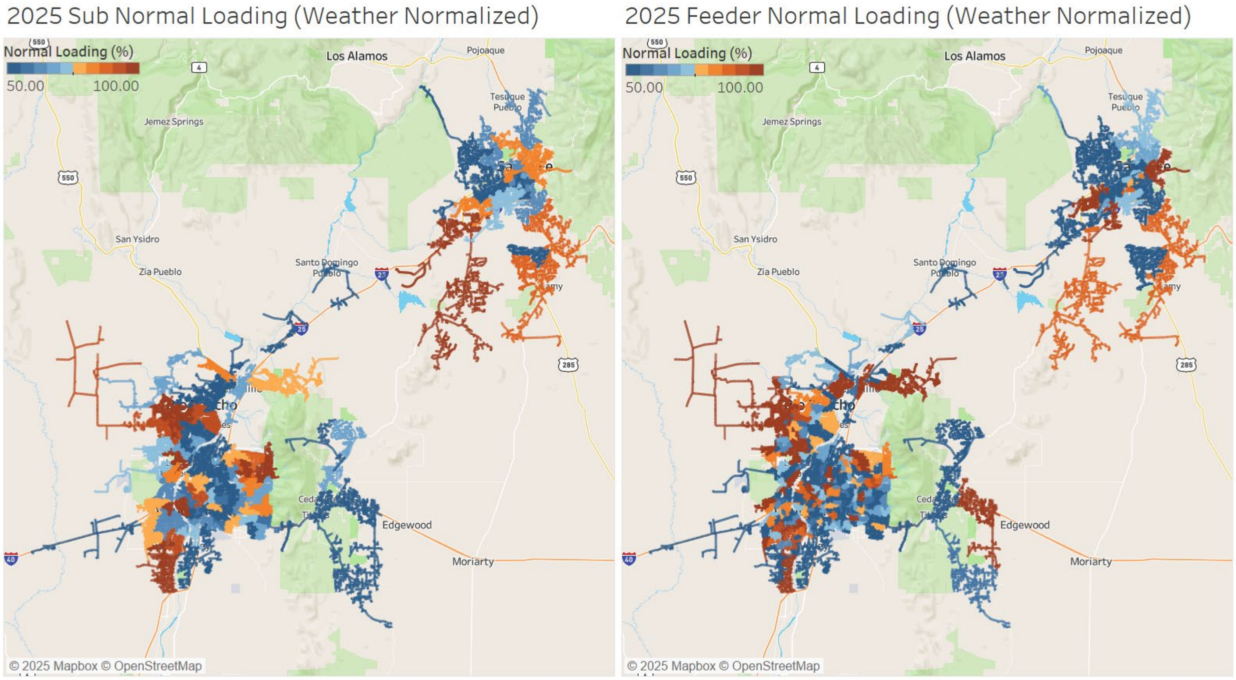
Figure 18: Heat Map of 2025 Normalized Loading Factors – PNM Territory



2025 Sub Normal Loading (Weather Normalized)

2025 Feeder Normal Loading (Weather Normalized)

Figure 19: Heat Map of 2025 Normalized Loading Factors – Albuquerque, Santa Fe, and Sandoval



2025 Sub Normal Loading (Weather Normalized)

2025 Feeder Normal Loading (Weather Normalized)

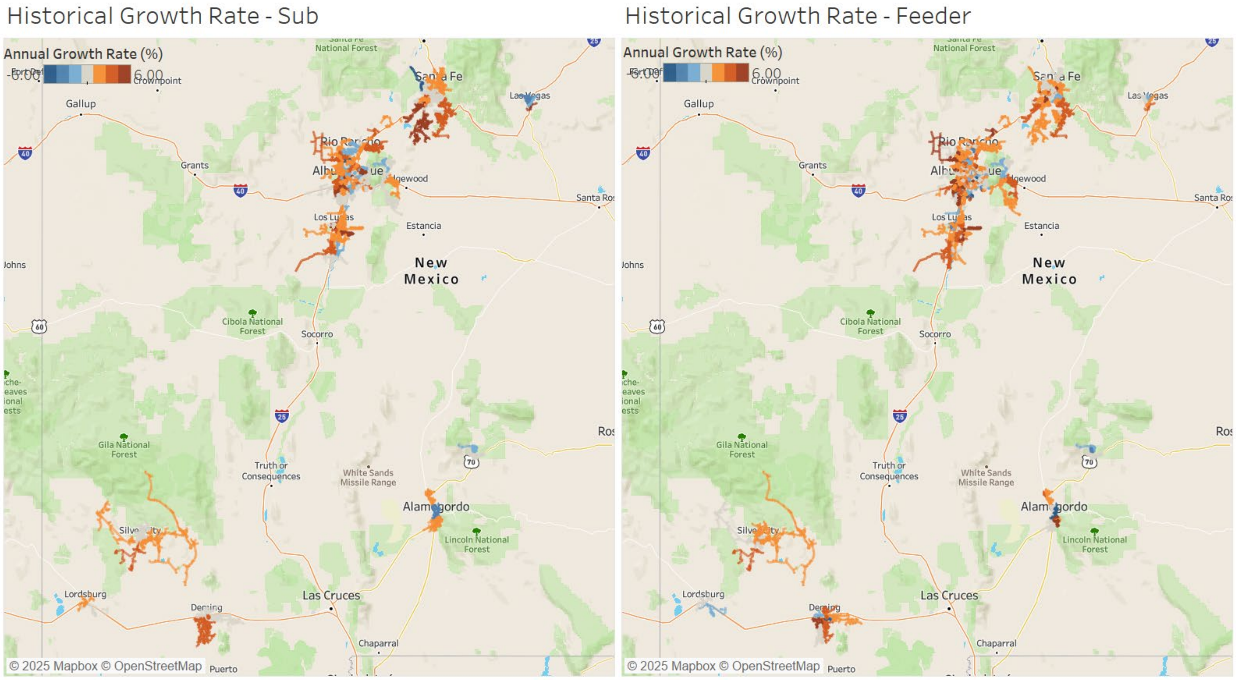
The DSA team estimated compound annual growth rate of each feeder and substation transformers. Table 10 summarizes the number of substation transformers and feeders falling into different bins of annual growth rate. Many feeders (306) and transformers (108) fall within the -2% to 2% growth rate category, indicating that they have experienced relatively flat growth. However, only a few feeders (34) and transformers (3) exhibited growth at a rate of 6% or higher.

Table 10: Overview of Weather-Normalized Annual Growth Rates

Annual Growth Rate (%)	# of substation transformers	# of feeder
Less than -6%	2	1
-6% to -2%	10	33
-2% to 2%	108	306
2% to 6%	41	129
6% or higher	3	34
Total	**165**	**503**

Figure 20 and Figure 21 show the growth rates estimated by the DSA team. Figure 20 shows results for the overall PNM service territory, while Figure 21 provides a focused view of the Albuquerque, Santa Fe, and Sandoval zones. Shades of blue indicate declining loads while orange and dark orange indicate load growth. Grey indicates a flat growth rate (e.g. close to zero). There is not a clear pattern of where growth and negative growth are happening, but rather positive and negative growth rates are interspersed throughout the territory. It is worth noting that most components are experiencing flat or slight growing shown as grey to light orange. The location-specific growth rates were used to develop probabilistic 20-year forecasts for each individual feeder and substation transformer. For each component, the location-specific growth rate was applied for the first five years and then converged to the PNM average growth rate by year ten. This approach was adopted since it can be unrealistic to project 20 years of trends based on five years of historical data for areas with high growth or rapid decline. A couple of components with extreme high or low growth rate were replaced with system level growth rate at 2.1%.

Figure 20: Historical Growth Rates – PNM Territory


Historical Growth Rate - Sub

Historical Growth Rate - Feeder

Figure 21: Historical Growth Rates – Albuquerque, Santa Fe, and Sandoval

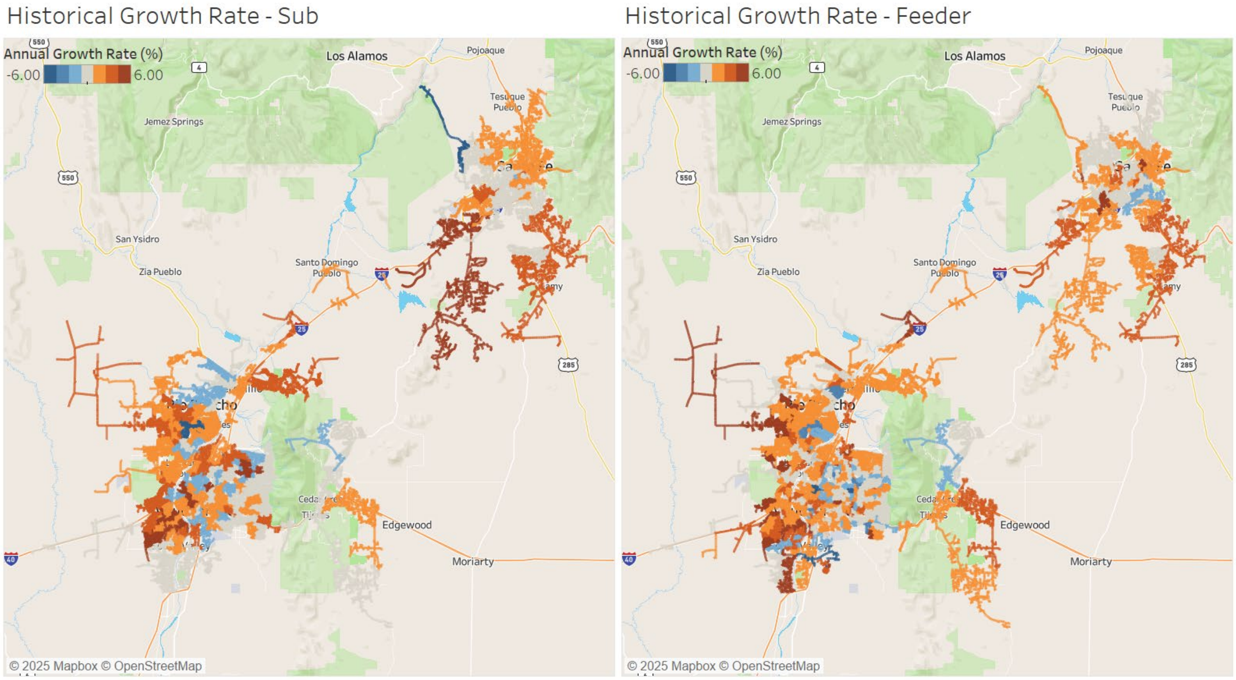
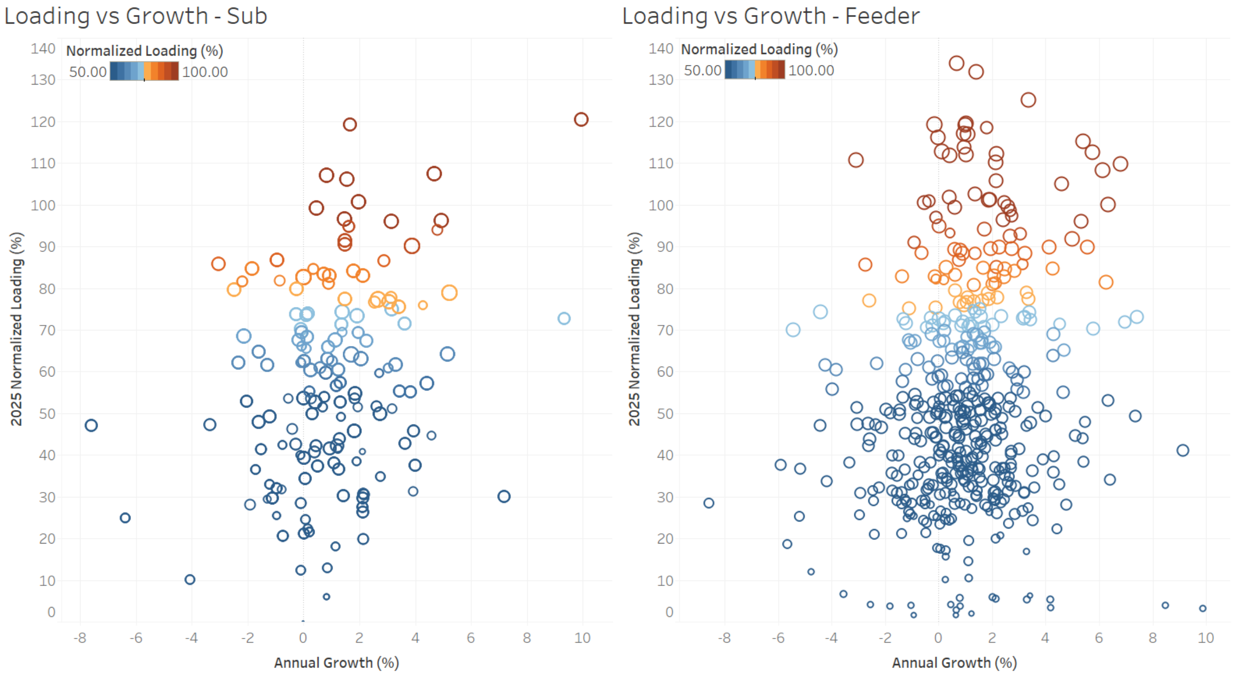


Figure 22 compares the annual load growth rate to the loading factor (weather-normalized peak divided by the location's normal rating) for each of PNM's feeders and substation transformers. Some are experiencing slowing growth or declining loads or have ample room for growth without having to upgrade them. Locations with a growth rate above 0% are experiencing growth, and locations where the loading factor is closer to 100% have less room for growth. Several feeders and substation transformers are highly loaded and growing, indicating a high likelihood of overloading. This chart, however, does not factor in the uncertainty of future growth patterns. For reference, the color reflects the loading factor, and the bubble size is proportional to the component's size (as defined by peak MVA). For the purposes of this study, the bubbles in the upper-right quadrant of the graph below are most important because they are locations that are both highly loaded and growing.

Figure 22: Growth Rates Versus Room for Growth

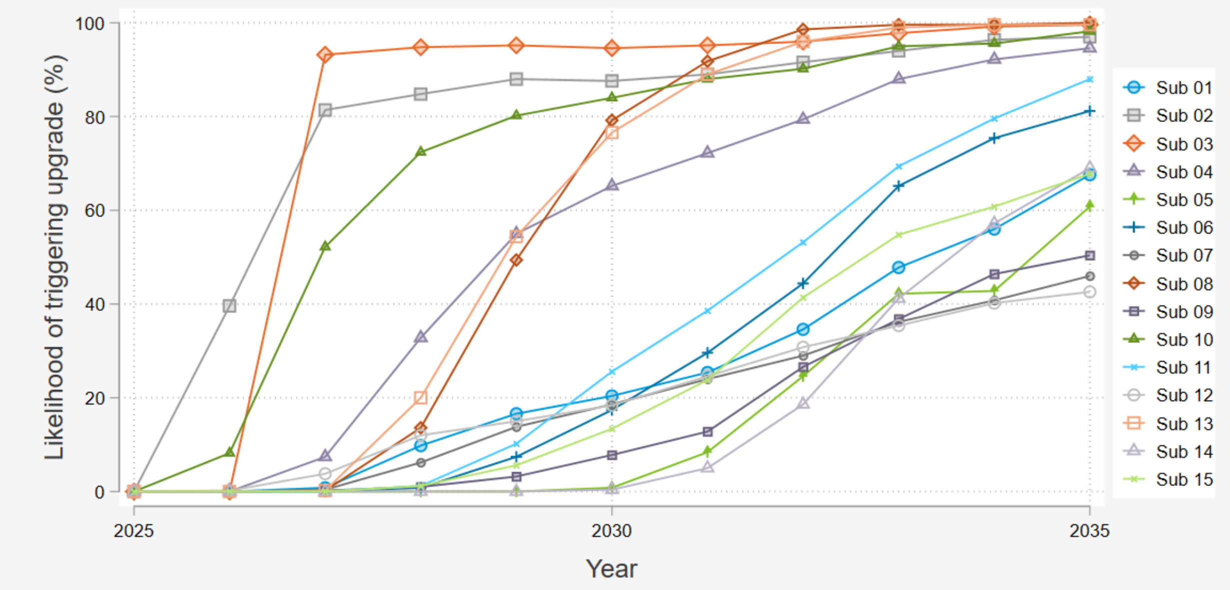


Bubble size is proportional to the annual peak MVA with weather normalization of the site. The color reflects the overall loading for each site based on 2025 data. A few outliers were removed from the figure.

3.3 DISTRIBUTION SYSTEM LIKELIHOOD OF UPGRADES

Figure 23 summarizes the likelihood of triggering an infrastructure upgrade if the historical load trends continue. This figure presents data for 15 randomly selected substation transformers with a likelihood greater than 10% of triggering upgrades by 2035. For Sub 3 in the figure, the likelihood of triggering an upgrade increases rapidly, approaching 100%, due to rising demand trends. In some cases, the likelihood of triggering an upgrade increases steadily over time. For those systems, peak demand reductions from EE programs lower the likelihood of triggering an upgrade, deferring capital investment, or potentially avoiding it entirely if native loads begin to decline.

Figure 23: PNM Likelihood of Triggering Upgrades



Randomly selected substation transformers with likelihood greater than 10% of triggering upgrades by 2035.

3.4 TRANSMISSION AND DISTRIBUTION DEFERRAL VALUE

Distribution costs are location specific. Locations with potential infrastructure deferral value are those where load growth is occurring and available capacity is limited. However, not all locations with a high likelihood of overload are considered deferrable. If the overload risk occurs too soon, the location is unlikely to yield deferral benefits.

The DSA team defined a "beneficial" location as one with (1) a violation risk greater than 10% within the next 10 years, and (2) a violation risk below 50% within the next three years. A violation is defined using a two-part criterion: peak load exceeding the normal rating for two consecutive years, or peak load exceeding the emergency rating. Based on these criteria, the DSA team compiled a list of beneficial locations at both the substation transformer and feeder levels. This list was reviewed with the PNM Distribution team to classify each hypothetical upgrade into four categories as shown in Figure 24. Most of the beneficial locations were classified as potentially deferrable for both substation and transformer and others spread into three other categories. It is worth noting that 16 substation transformers and 65 feeders exhibit overload risk too soon (defined as greater than 50% risk within the next three years) and therefore are not considered beneficial for deferral.

Figure 24: Beneficial Distribution Location Classification

Classification	Number of Substation Transformers	Number of Feeders
Already in the capital plan	1	3
Deferral not possible	4	6
Project not required (e.g., can be resolved through load transfer)	4	4
Potentially deferrable	18	44
Total	**27**	**57**

Similarly, 39 deferable transmission projects were identified and analyzed for deferral value using system coincident peak load on substation transformers. In contrast to the distribution projects which were specific to a single distribution feeder or substation transformer, each transmission project was specific to a transmission line. Load flow analysis was performed across substation transformers with load modifiers (planning load) and without load modifiers (valuation load) to identify the limiting element and projected future investments. The first year of deferral was the projected in-service year under the without load modifiers scenario. The last year of deferral was assumed to be the year before the in-service year under the with load modifiers scenario. Load flow calculations were used to proportionally allocate deferral value to substation transformers where load reductions helped alleviate the transmission constraint

For both distribution and transmission value to be realized by delaying upgrades, a sufficient magnitude of demand reductions at the right location, time, and season is necessary. For system-wide untargeted values, the estimates consider the likelihood that reductions would be in locations with value due to random chance. The DSA team emphasizes that system-wide value is a load-weighted average of areas where reductions do lead to deferral of distribution or transmission investments.

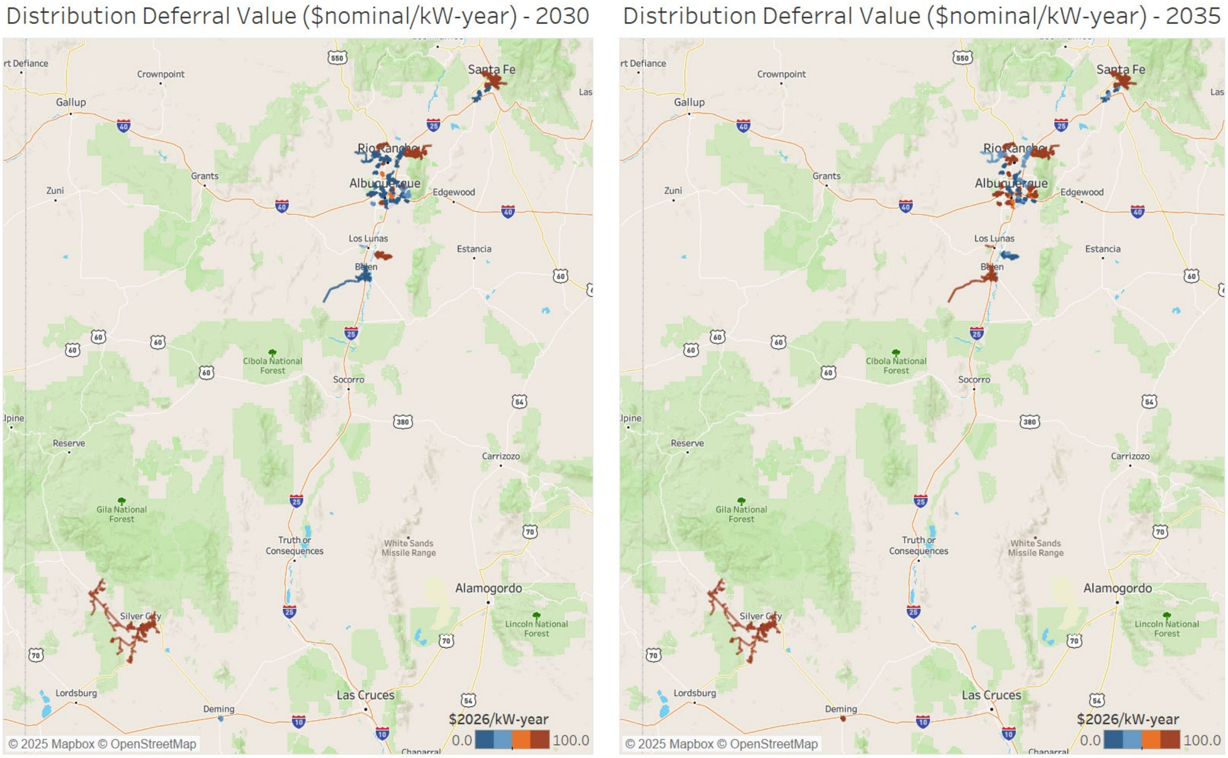
To calculate the total deferral value, the DSA team aggregated the deferral value at the feeder and substation transformer levels, then incorporated the deferral value of transmission. Table 11 shows the total deferral value for the PNM territory at the system level, as well as the 10-year levelized value from 2028 to 2037. From 2026 to 2045, the total deferral value increases from $1.73/kW-year to $66.59/kW-year, peaking at $81.43/kW-year in 2039. The distribution value is consistently lower than the transmission value. Both components of the distribution value, the distribution feeder and the substation transformer values, as well as the transmission value show a steady increase initially but decreases towards the end of the study period. This trend may be attributed to the expectation that many sites will exceed their maximum deferral periods by around 2040, at which point these sites will be considered non-deferrable, thereby necessitating infrastructure investments.

Table 11: PNM Deferral Value (load-weighted average, nominal $/kW-year)

Year	Distribution		Transmission	Total
	Feeder	Substation Transformer		
2026	$1.73	$0.00	$0.00	$1.73
2027	$1.70	$0.82	$0.00	$2.51
2028	$2.51	$4.44	$28.96	$35.91
2029	$3.82	$7.72	$27.72	$39.26
2030	$4.80	$9.32	$27.60	$41.72
2031	$5.71	$10.23	$27.53	$43.48
2032	$6.54	$11.90	$48.17	$66.61
2033	$8.19	$13.73	$48.12	$70.04
2034	$9.17	$14.81	$47.03	$71.02
2035	$10.43	$15.86	$47.06	$73.35
2036	$9.83	$16.52	$50.78	$77.13
2037	$10.21	$16.46	$50.17	$76.85
2038	$10.62	$14.89	$45.43	$70.94
2039	$10.31	$14.31	$56.72	$81.34
2040	$10.49	$14.72	$46.47	$71.68
2041	$11.01	$15.31	$46.50	$72.82
2042	$10.55	$15.17	$47.73	$73.45
2043	$10.80	$15.82	$47.63	$74.25
2044	$9.63	$14.32	$47.60	$71.55
2045	$8.18	$12.69	$45.72	$66.59
10-year levelized value (2028-2037, $2025)	**$6.51**	**$10.89**	**$35.76**	**$53.16**

Figure 25 provides a heat map of the distribution deferral value in 2030 and 2035. The distribution deferral value is concentrated in specific pockets rather than across the PNM service territory. Areas with relatively higher deferral value include Southwest, Belen, Albuquerque, Sandoval, and Santa Fe. Figure 26 shows an analogous heat map of the transmission deferral value in 2030 and 2035. The transmission deferral value is still concentrated but somewhat less so than the distribution deferral value because the system is somewhat networked and load reductions on multiple substation transformers can help reduce load on the limiting element for a given project.

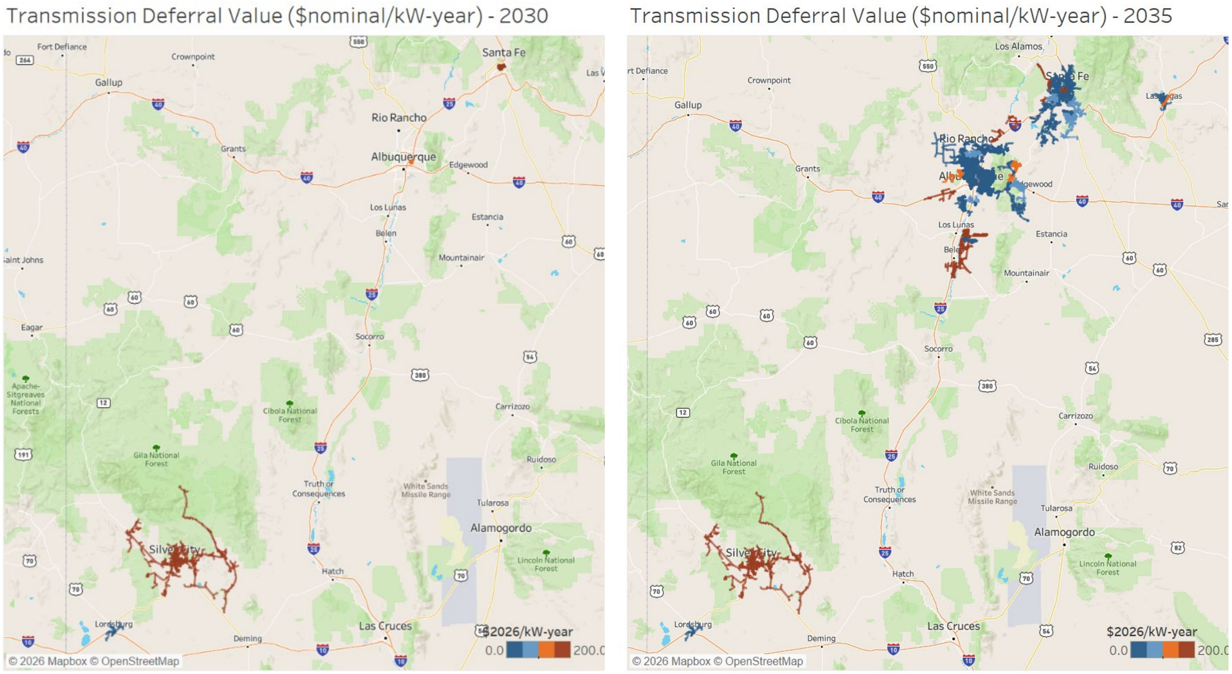
Figure 25: Heat Map of PNM Distribution Deferral Value



Distribution Deferral Value ($nominal/kW-year) - 2030

Distribution Deferral Value ($nominal/kW-year) - 2035

Figure 26: Heat Map of PNM Transmission Deferral Value



Transmission Deferral Value ($nominal/kW-year) - 2030

Transmission Deferral Value ($nominal/kW-year) - 2035

Notably, the most imminent investments, those with high risk in the next one to three years, are largely not deferrable. This means that the avoided cost is also a function of the period over which investment deferral is valued. Table 12 shows 10-year levelized deferral value as a function of the ten-year valuation period start year. Selecting a later start year means that there is more value in all ten valuation years, which translates to as much as double the value.

Table 12: PNM 10-Year Levelized Deferral Value Sensitivity to Valuation Start Year (load-weighted average, nominal $/kW-year)

Start Year for 10-Year Levelized Value	Distribution		Transmission	Total
	Feeder	Substation Transformer		
2026	$4.75	$7.46	$24.38	$36.58
2027	$5.59	$9.17	$29.83	$44.60
2028	$6.51	$10.89	$35.76	$53.16
2029	$7.42	$12.14	$37.87	$57.42
2030	$8.16	$13.09	$41.08	$62.34
2031	$8.83	$13.89	$40.43	$63.15
2032	$9.45	$14.59	$43.22	$67.26
2033	$9.95	$15.03	$45.41	$70.39
2034	$10.25	$15.26	$46.04	$71.55
2035	$10.36	$15.27	$46.54	$72.18

3.5 TIME-DIFFERENTIATED VALUE

Deferral of an infrastructure upgrade requires sufficient magnitude of load reduction at the right location at the right time of day during the right season. For example, no amount of summer peak demand reduction will defer an upgrade to a substation with projected overloads in the winter. The DSA team broke out the avoided distribution costs into summer and winter categories and allocated them across 24 hours.

Although the peak load relief needed to defer upgrades is driven by the projected exceedance of the peak load relative to the available capacity for a site, load relief needs are not restricted to the single peak hour. Rather, load relief is required in all hours where load exceeds the available capacity on the limiting element for a given site. As such, analyzing all hours where load relief is needed can reveal the concentration of need by hour of day and for how long (peak window duration) load relief is needed. Understanding the need by hour is particularly critical for assessing the extent to which specific EE program offerings can provide the necessary load relief. For example, load reductions in a business that closes at 5 PM will provide limited value on a feeder with projected overloads at 7 PM. Similarly, PNM's load management (LM) resources offer very little available capacity in the winter and can therefore only capture summer value.

The seasonal peak day load shape for each component was used to allocate value across hours. This allocation was performed at a granular level and then aggregated to reflect a territory-wide perspective. Figure 27 shows the varying value allocation by hour of day for each year for the 1-in-2 weather normalized distribution peak day load shape weighed to the system level. Note that as load relief needs change year over year, deferral value changes and the allocation of that value across hours also changes. In the summer season, load relief need peaks at hour 19 (6 to 7 PM) for years 2026-2028 and shifts to hour 20 (7-8 PM) in 2029 and 2030. In the winter season, the need peaks at hour 8 (7 to 8 AM) but there is a second concentration of value in the early evening at hour 19 (6-7 PM).

Figure 27: Yearly Distribution Value Allocation by Hour

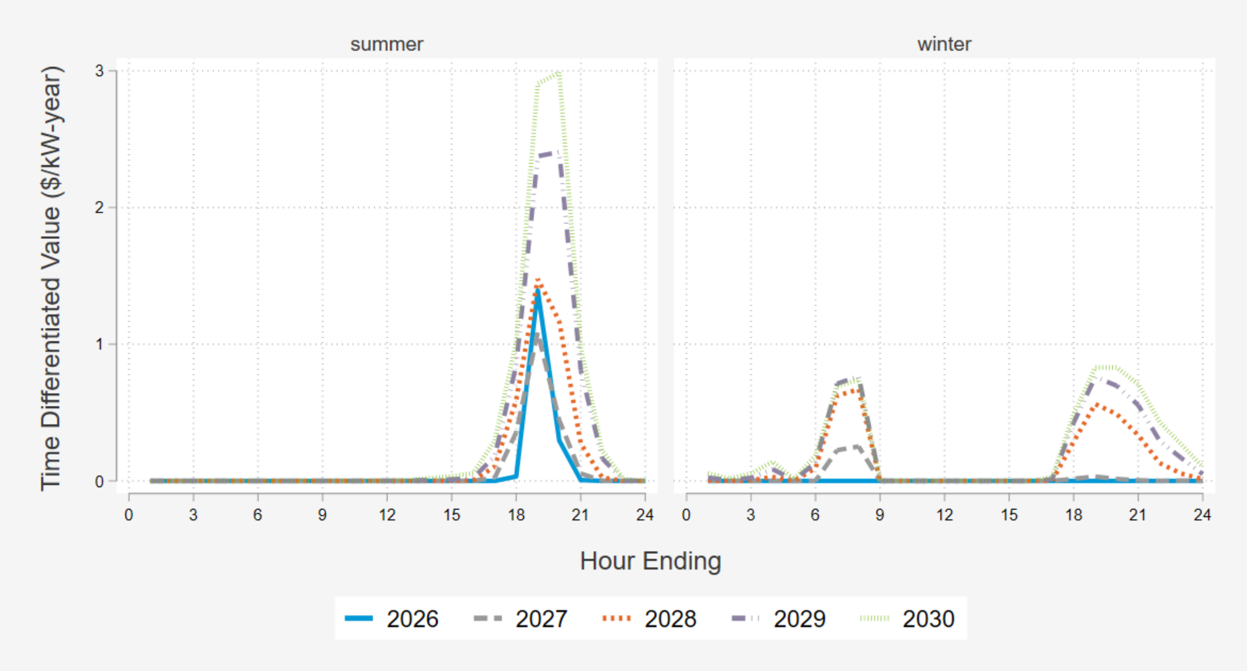


Figure 28 shows the varying value allocation by hour of day for each year for the 1-in-2 weather normalized system coincident peak day load shape, assuming it is concentrated in the hours that would be affected by a 15 % reduction in system peak. This approach is taken to reflect that system peaking risk is not entirely concentrated in a single hour, rather there is system peaking risk in adjacent hours. The consistency in hourly allocation across years reflects the relative consistency of the system peak day load shape across years. The increase in magnitude of the time differentiated value from year to year reflects the increase in annual transmission value over time. Because transmission projects are largely driven by PNM system peak conditions, which always occur in the summer, there is no transmission value in the winter.

Figure 28: Yearly Transmission Value Allocation by Hour

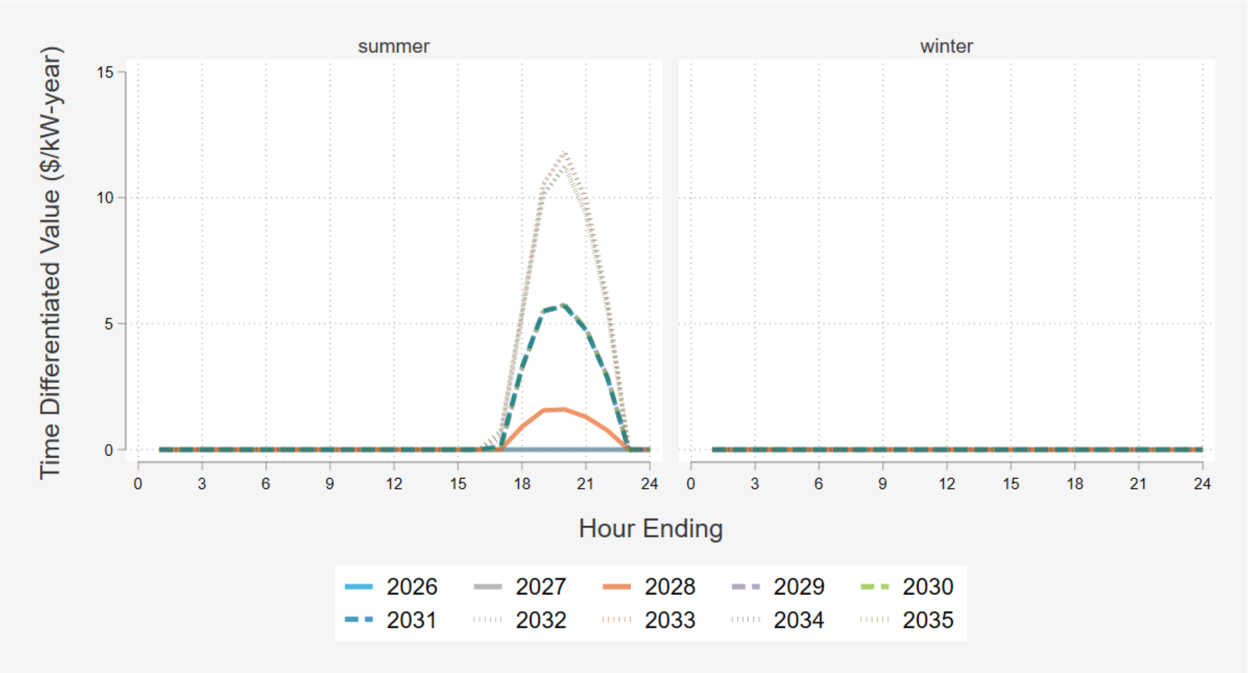


Table 13 shows the territory-wide time differentiated value by season and hour of day based on 10-year levelized value. Note that the value allocation is spread over a wide number of hours, reflecting the variation in load shape across the underlying systems. Most components peak in the summer, resulting in 70% of the deferral value being allocated to this season. The need for load relief peaks during HE19 (6-7 PM) in summer, while the load relief requirement shows two peaks in winter – One in the morning around HE8 (7-8 AM) and another in the evening around HE21 (8-9 PM).

Table 13: Time Differentiated Deferral Value – 10-Year Levelized Value

		Distribution			
Season	Hour	Feeder	Substation Transformer	Trans-mission	Total
summer	1	$0.00	$0.00	$0.00	$0.00
summer	2	$0.00	$0.00	$0.00	$0.00
summer	3	$0.00	$0.00	$0.00	$0.00
summer	4	$0.00	$0.00	$0.00	$0.00
summer	5	$0.00	$0.00	$0.00	$0.00
summer	6	$0.00	$0.01	$0.00	$0.01
summer	7	$0.00	$0.00	$0.00	$0.00
summer	8	$0.00	$0.00	$0.00	$0.00
summer	9	$0.00	$0.01	$0.00	$0.01
summer	10	$0.00	$0.01	$0.00	$0.01
summer	11	$0.01	$0.01	$0.00	$0.02
summer	12	$0.02	$0.02	$0.00	$0.03
summer	13	$0.03	$0.03	$0.00	$0.06
summer	14	$0.08	$0.05	$0.00	$0.13
summer	15	$0.09	$0.07	$0.00	$0.16
summer	16	$0.11	$0.11	$0.00	$0.22
summer	17	$0.28	$0.34	$0.97	$1.58
summer	18	$0.77	$0.83	$5.02	$6.63
summer	19	$1.76	$1.49	$8.64	$11.89
summer	20	$1.90	$1.28	$9.17	$12.35
summer	21	$0.94	$0.77	$7.50	$9.21
summer	22	$0.34	$0.34	$4.45	$5.13
summer	23	$0.06	$0.06	$0.00	$0.12
summer	24	$0.01	$0.01	$0.00	$0.01
10-year levelized value (2028-2037, $2025)		***$6.39***	***$5.44***	***$35.76***	***$47.59***

		Distribution			
Season	Hour	Feeder	Substation Transformer	Trans-mission	Total
winter	1	$0.00	$0.10	$0.00	$0.10
winter	2	$0.00	$0.07	$0.00	$0.07
winter	3	$0.00	$0.09	$0.00	$0.09
winter	4	$0.00	$0.13	$0.00	$0.13
winter	5	$0.00	$0.06	$0.00	$0.06
winter	6	$0.00	$0.20	$0.00	$0.20
winter	7	$0.00	$0.43	$0.00	$0.43
winter	8	$0.01	$0.51	$0.00	$0.51
winter	9	$0.01	$0.03	$0.00	$0.04
winter	10	$0.01	$0.00	$0.00	$0.01
winter	11	$0.01	$0.00	$0.00	$0.01
winter	12	$0.00	$0.00	$0.00	$0.00
winter	13	$0.00	$0.00	$0.00	$0.00
winter	14	$0.00	$0.00	$0.00	$0.00
winter	15	$0.00	$0.00	$0.00	$0.00
winter	16	$0.00	$0.02	$0.00	$0.02
winter	17	$0.01	$0.06	$0.00	$0.07
winter	18	$0.02	$0.32	$0.00	$0.34
winter	19	$0.02	$0.64	$0.00	$0.66
winter	20	$0.02	$0.79	$0.00	$0.80
winter	21	$0.01	$0.81	$0.00	$0.82
winter	22	$0.01	$0.65	$0.00	$0.65
winter	23	$0.00	$0.35	$0.00	$0.36
winter	24	$0.00	$0.16	$0.00	$0.17
10-year levelized value (2028-2037, $2025)		***$0.13***	***$5.45***	***$0.00***	***$5.57***

3.6 VALUE OF ENERGY EFFICIENCY

Table 14 shows the territory-wide 10-year levelized value of energy efficiency. EE is relatively more coincident with summer peak and less coincident with winter peaks, resulting in higher EE value in summer than in winter. In the summer, the value of EE is concentrated in the afternoon peaking at HE20 (7–8 PM) and reaches approximately $12.35/kW-year in that top hour. In the winter, unlike the load-relief requirement, which shows two distinct peaks, the EE value is more broadly distributed across the evening, midnight, and morning hours. The value is entirely comprised of distribution value since there is no transmission value in the winter. The highest winter values occur during the late evening from HE19 to HE23 (6-11PM), at roughly $0.10. These are the values that would be relevant for incorporation into future cost-effectiveness assessment of EE portfolio resources in PNM territory. This value reflects the load shape constraints of the expected PNM EE portfolio. However, individual EE measures will have different levels of coincidence with PNM need. For example, space cooling efficiency measures will be most coincident with summer resource needs and space heating measures will be most coincident with winter resource needs. Other measures, such as lighting, will be less "coincident" and therefore deliver less value. This should be considered when applying values to individual measures rather than at the portfolio level.

Table 14: Value of Energy Efficiency – 10-Year Levelized Value

		Distribution			
Season	Hour	Feeder	Substation Transformer	Trans-mission	Total
summer	1	$0.00	$0.00	$0.00	$0.00
summer	2	$0.00	$0.00	$0.00	$0.00
summer	3	$0.00	$0.00	$0.00	$0.00
summer	4	$0.00	$0.00	$0.00	$0.00
summer	5	$0.00	$0.00	$0.00	$0.00
summer	6	$0.00	$0.00	$0.00	$0.00
summer	7	$0.00	$0.00	$0.00	$0.00
summer	8	$0.00	$0.00	$0.00	$0.00
summer	9	$0.00	$0.00	$0.00	$0.00
summer	10	$0.00	$0.00	$0.00	$0.00
summer	11	$0.00	$0.00	$0.00	$0.00
summer	12	$0.00	$0.00	$0.00	$0.01
summer	13	$0.01	$0.01	$0.00	$0.02
summer	14	$0.03	$0.02	$0.00	$0.05
summer	15	$0.04	$0.03	$0.00	$0.07
summer	16	$0.06	$0.07	$0.00	$0.14
summer	17	$0.19	$0.26	$0.62	$1.08
summer	18	$0.55	$0.67	$3.37	$4.60
summer	19	$1.30	$1.19	$5.90	$8.39
summer	20	$1.44	$0.97	$5.90	$8.32
summer	21	$0.65	$0.52	$4.46	$5.63
summer	22	$0.21	$0.20	$2.54	$2.95
summer	23	$0.03	$0.03	$0.00	$0.06
summer	24	$0.00	$0.00	$0.00	$0.01
10-year levelized value (2028-2037, $2025)		***$4.54***	***$3.99***	***$22.80***	***$31.32***

		Distribution			
Season	Hour	Feeder	Substation Transformer	Trans-mission	Total
winter	1	$0.00	$0.01	$0.00	$0.01
winter	2	$0.00	$0.01	$0.00	$0.01
winter	3	$0.00	$0.01	$0.00	$0.01
winter	4	$0.00	$0.01	$0.00	$0.01
winter	5	$0.00	$0.01	$0.00	$0.01
winter	6	$0.00	$0.02	$0.00	$0.02
winter	7	$0.00	$0.05	$0.00	$0.05
winter	8	$0.00	$0.06	$0.00	$0.07
winter	9	$0.00	$0.00	$0.00	$0.01
winter	10	$0.00	$0.00	$0.00	$0.00
winter	11	$0.00	$0.00	$0.00	$0.00
winter	12	$0.00	$0.00	$0.00	$0.00
winter	13	$0.00	$0.00	$0.00	$0.00
winter	14	$0.00	$0.00	$0.00	$0.00
winter	15	$0.00	$0.00	$0.00	$0.00
winter	16	$0.00	$0.00	$0.00	$0.00
winter	17	$0.00	$0.01	$0.00	$0.02
winter	18	$0.01	$0.08	$0.00	$0.08
winter	19	$0.01	$0.19	$0.00	$0.19
winter	20	$0.01	$0.22	$0.00	$0.22
winter	21	$0.00	$0.22	$0.00	$0.22
winter	22	$0.00	$0.16	$0.00	$0.16
winter	23	$0.00	$0.07	$0.00	$0.07
winter	24	$0.00	$0.02	$0.00	$0.02
10-year levelized value (2028-2037, $2025)		***$0.04***	***$1.14***	***$0.00***	***$1.18***

The territory-wide 10-year levelized value of energy efficiency shown in Table 14 corresponds to the ten-year period from 2028 to 2037. In practice, the applicable years over which value would be levelized should correspond to the install year and measure life of the efficiency measure being installed. Table 15 shows the value of energy efficiency in individual years that should be used as inputs to this calculation.

Table 15: PNM Value of Energy Efficiency (load-weighted average, nominal $/kW-year)

Year	Distribution		Transmission	Total
	Feeder	Substation Transformer		
2026	$1.23	$0.00	$0.00	$1.23
2027	$1.19	$0.32	$0.00	$1.51
2028	$1.80	$1.60	$17.75	$21.15
2029	$2.74	$3.18	$17.73	$23.65
2030	$3.46	$3.92	$17.68	$25.06
2031	$4.09	$4.43	$17.67	$26.19
2032	$4.66	$5.46	$30.83	$40.96
2033	$5.84	$6.64	$30.78	$43.26
2034	$6.51	$7.31	$30.04	$43.86
2035	$7.39	$8.05	$30.02	$45.46
2036	$6.98	$8.57	$32.36	$47.91
2037	$7.20	$8.71	$31.94	$47.85
2038	$7.45	$8.57	$28.90	$44.92
2039	$7.19	$8.52	$36.10	$51.81
2040	$7.30	$8.91	$29.67	$45.89
2041	$7.65	$9.51	$29.69	$46.85
2042	$7.33	$9.59	$30.49	$47.41
2043	$7.62	$10.20	$30.43	$48.25
2044	$6.80	$9.30	$30.42	$46.52
2045	$5.78	$8.21	$29.22	$43.22
10-year levelized value (2028-2037, $2025)	**$4.58**	**$5.13**	**$22.80**	**$32.50**

While the values estimated for this study are specific to PNM, the avoided T&D values used previously by PNM for cost-effectiveness purposes were not specific to PNM or developed using PNM data. Table 16 compares the annual value of EE from this study to the previous EE avoided cost values, from the PNM 2020 Proposed Plan. Years are only included for which values were produced in both studies. Notably, the values from this study are higher than the values previously used by PNM.

Table 16: Comparison of Study Value of EE with PNM 2020 EE Proposed Plan (EE Avoided T&D)

Year	PNM 2020 EE and LM Proposed Plan (EE Avoided T&D)	PNM 2025 Avoided T&D Cost Study (Value of EE)
2026	$5.39	$1.23
2027	$5.47	$1.51
2028	$5.55	$21.15
2029	$5.63	$23.65

Year	PNM 2020 EE and LM Proposed Plan (EE Avoided T&D)	PNM 2025 Avoided T&D Cost Study (Value of EE)
2030	$5.72	$25.06
2031	$5.80	$26.19
2032	$5.89	$40.96
2033	$5.98	$43.26
2034	$6.07	$43.86
2035	$6.16	$45.46
2036	$6.25	$47.91
2037	$6.34	$47.85
2038	$6.44	$44.92
2039	$6.54	$51.81

4 CONCLUSIONS AND RECOMMENDATIONS

This study was designed to quantify the deferral value of peak demand reductions on PNM transmission and distribution investments. The study focused on quantifying the T&D costs associated with an increase or decrease of peak kW and season. A key outcome of the study was to highlight the fact that the avoided T&D costs associated with peak load reductions (load relief) vary widely within PNM territory. Table 17 presents some broad study findings, which are followed by potential enhancements to more precisely value EE program impacts at the local level.

Table 17: Key Study Findings

Finding	Detail
Load growth varies by location. Some pockets are experiencing load growth, and some are experiencing load decreases.	The DSA team estimated granular growth rates. In PNM service territory, growth trends varied by location. As a result, location specific growth-related T&D investments are required even when overall PNM loads are flat or declining.
The T&D avoided costs are concentrated in locations that are more heavily loaded.	A key component of distribution planning is the load factor: the weather-normalized peak demand divided by the operating limit. Not surprisingly, avoided costs are concentrated in more highly loaded locations. Conversely, locations with ample capacity to accommodate additional loads had lower avoided T&D costs.
Individual locations are generally winter or summer peaking, not both.	Most distribution locations – feeders and substation transformers – can be classified as winter or summer peaking except for a few feeders that are dual peaking. The implication is that the avoidable T&D cost for a specific location is concentrated in the summer or winter, but not both.
Resources that deliver load relief at the right location, in the right season, and at the right hours are more valuable.	The same energy efficiency resource can deliver different T&D benefits at two locations based on how well it coincides with the local peak load. To illustrate, a more efficient air conditioner does not provide T&D load relief on a winter peaking substation but does so on a summer peaking substation. Likewise, measures with load shapes that better coincide with the need for load relief are more valuable.
A valuation period further in the future produces higher deferral value.	The most imminent investments, those with high risk in the next one to three years, are largely not deferrable, so deferral value is sensitive to the deferral value period. A later valuation period produces higher deferral value because it excludes the imminent period with little deferral value.
The avoided T&D value and value of EE estimated for this study is specific to the PNM system.	Previously, the avoided T&D values used by PNM for cost-effectiveness purposes were not specific to PNM or developed using PNM data. The values estimated for this study are specific to PNM and are higher than the values previously used by PNM.

The study focused on developing PNM specific T&D avoided costs to inform the value of EE. Thus, the avoided T&D costs are presented as territory-wide value. To provide EE value for summer and winter, the DSA team separated avoided T&D costs by season. One of the main implications of the study is that avoided T&D costs estimates can be produced at a more granular level and differentiated by time and season. The added spatial and temporal granularity can help better target peak demand reductions in the locations, seasons, and hours where deferral value is highest. The DSA team recommends that PNM, the Commission, and stakeholders consider a more granular perspective on avoided T&D costs, as summarized below. The recommendations below may not be currently funded, and costs need to be considered alongside other research and program priorities.

1. **Explore separate T&D avoided costs for different locations.** For example, classify circuit feeders, transformers, terminals, and substations as winter or summer peaking and into one of three loading factor levels – low (<50%), medium (50-80%), and high (80% or more). Produce annual values by classification group and time-differentiate the value by hour and season. The approach would more accurately reflect where and when avoided T&D costs are concentrated while limiting the additional complexity.
2. **Update PNM tracking databases so the corresponding T&D classification group can be looked up based on the geospatial location.** This would allow PNM to assess if the energy efficiency measures are in areas with high or low T&D avoided cost value.
3. **Consider targeting energy efficiency at a highly loaded area.** The goal is to assess if energy efficiency resources with other resources such as batteries can cost-effectively help modify the load shapes, bend the growth, and defer upgrades.
4. **Track geospatial adoption of EE.** Dispersion modeling of the EE system forecast lacked locational granularity since premise level adoption data was not available to inform how adoption may vary by location, building characteristics, or premise usage patterns. Tracking of EE adoption by premise or at least by point of sale where efficiency measures were rebated would improve future modeling precision of the magnitude of locational EE. This would in turn improve the precision of estimates of deferral value and Value of EE.

Based on the analysis, the DSA team recommends the proposed values shown in Table 3 for future incorporation into future cost-effectiveness analyses of PNM programs. The avoided cost of T&D reflects the value to the system of unconstrained resources. The Value of EE reflects the ability of EE resources to deliver T&D value given load shape constraints of the expected PNM EE portfolio. The 10-year levelized value shown summarizes annual values that will be applied to the useful life of modifiers being valued. The Value of LM reflects the ability of Load Management resources to deliver T&D value given the mostly summer capacity of the PNM LM portfolio.

Table 18: Recommended PNM Avoided T&D Values ($2025)

Type of Value	Description	Transmission	Distribution
Avoided T&D	10-year levelized value (2028-2037, $2025)	$35.76	$17.40
Value of EE	10-year levelized value (2028-2037, $2025)	$22.80	$9.71

Type of Value	Description	Transmission	Distribution
Value of LM	9-year levelized value (2027-2035, $2025)	$30.88	$13.26

5 APPENDIX A – GRANULAR FORECASTING METHODS

5.1 ADJUSTMENTS FOR ECONOMIC DEVELOPMENT LUMP LOAD

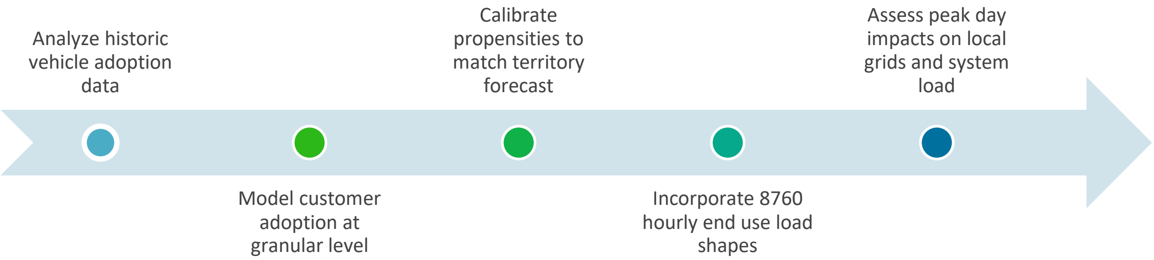
Economic development loads are simply new, large loads that do not appear each year at each location. These loads tend to concentrate in specific pockets and can potentially lead to transmission and distribution projects due to their relatively large size. However, the addition of economic development loads does not always necessitate transmission and distribution expansion projects. If the feeder or substation transformer serving the economic development has sufficient capacity to serve the additional load, no upgrade is required. PNM tracks expected large load additions through economic development efforts and initial discussions with customers considering construction of large new facilities. Typically, these scoping efforts include a projected facility size in MW.

For this study, the team assumes all planned economic development projects will be built as scheduled. The plan includes eight distribution-level economic development projects. Seven projects are associated with specific feeders, while one requires the construction of a new substation transformer. For projects with identified feeders, the DSA team allocated the expected load to the corresponding feeder using the projected MW magnitude and capacity factor, treating economic development load as flat across all hours and seasons. For the project requiring a new feeder or substation transformer, the load is included in the system-level forecast but is not assigned to specific distribution components.

5.2 ADJUSTMENTS FOR LOAD GROWTH FROM ELECTRIC VEHICLES

Figure 29 shows the methodology used to produce propensity scores for electric vehicle (EV) adoption at the premise level. Premises were identified as having at least one EV if the premise is on a whole-home EV rate (WHEV). Because only premises on the WHEV billing rate were classified as having an EV, this current penetration is likely an underestimate of the true count of premises in the PNM territory with an EV. Nevertheless, the property and billing characteristics of these premises can still be used to produce a likelihood of EV adoption for the remaining premises in the territory through the propensity modeling process.

Figure 29: EV Granular Forecasting Methodology



5.2.1 PROPENSITY SCORE DEVELOPMENT

Figure 30 details the methodology used to develop propensity scores for each premise. For light-duty vehicles, propensity scores were produced for each premise using the decision tree model XGBoost. XGBoost classifies a premise as either having an electric vehicle or not having an electric vehicle based on a set of premise features, such as the square footage of the home, the age of the home, the annual electricity usage at the premise, and whether the premise already has additional load modifiers, most notably solar.

Figure 30: EV Propensity Modeling Methodology Overview

STEP 1:
Exploratory Data Analysis

- Analyze customers who have and have not adopted the DER/load modifier in question
- Explore relationship of all possible predictive variables for DER adoption
  - ✓ Correlation
  - ✓ Plots
  - ✓ Bivariate regressions
- Identify the key predictors of adoption
- Identify non-linear patterns

STEP 2:
Machine Learning Model

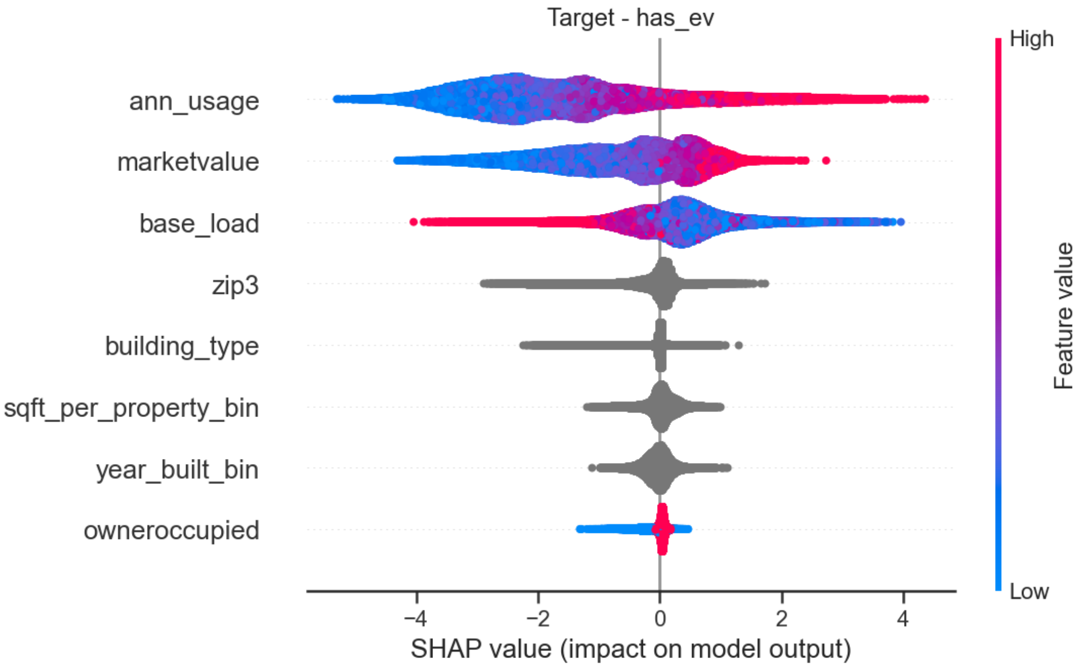
- Split data into training/testing data
- Train Model on predictive features
  - ✓ XG Boost
  - ✓ Model identifies what best predicts the outcome
  - ✓ Captures non-linear and linear relationships
  - ✓ The models iterates and learns, improving with each iteration
- Models are assessed using the testing data

STEP 3:
Apply to all Customers

- Predict likelihood of adoption (today) for each premise and DER/Load Modifier – aka propensity score
- The predictions factor in customer specific information and helps us distinguish early adopters from late adopters
- The propensity scores are scaled so the sum of the adoption probabilities for each year equals the system level forecast (Calibration)
- When aggregated by feeder, it provides the expected adoption by year and DER for each feeder

Figure 31 shows the most important features in predicting EV adoption. Among these features are the gross annual usage of the customer, as well as property-specific features such as the zip code, the building type (e.g., single-family, multi-family, etc.), the square footage, the year built, and whether the property is owner occupied or not. Typically, higher gross annual usage, high square footage, and newer homes impact the propensity model positively.

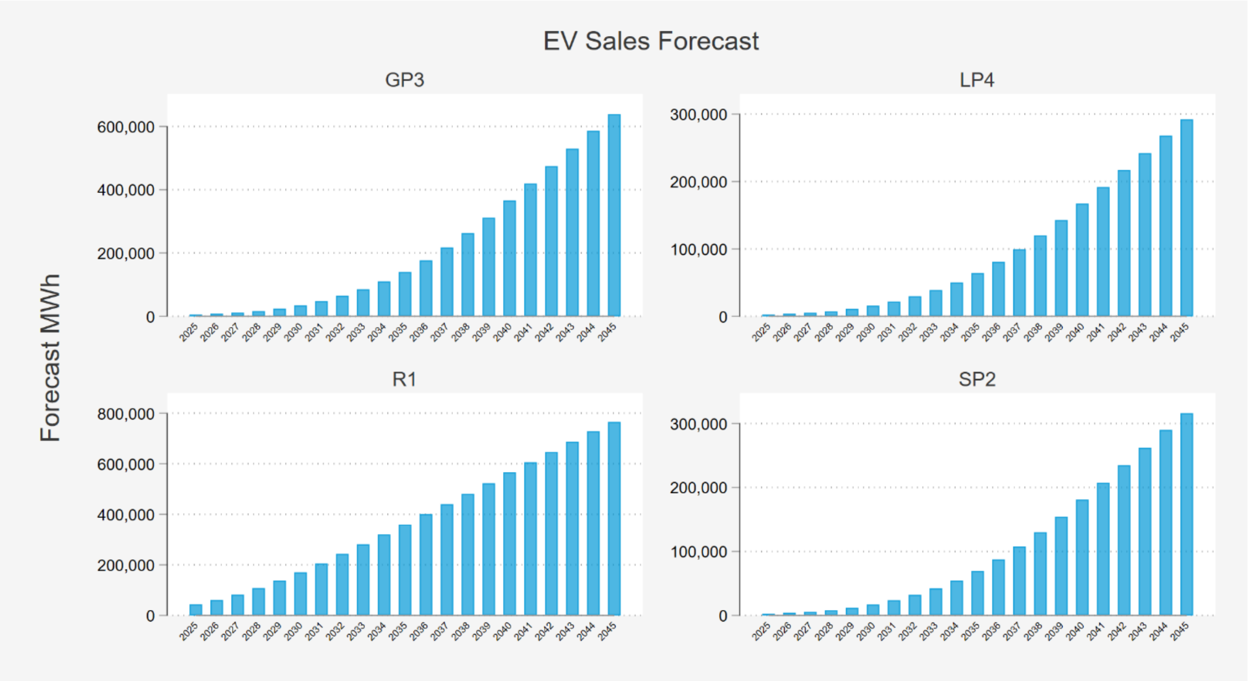
Figure 31: EV Propensity Model SHAP Feature Importance



5.2.2 CALIBRATION TO SYSTEM LEVEL FORECAST

While the propensity scores dictate where predicted, future demand from EV at-home charging occurs, the total magnitude of annual charging consumption is primarily driven by the system-level forecast. For this study, PNM provided the system-level forecast of sales (in MWh) by rate class. This forecast is shown in Figure 35. Although the forecast of EV charging sales is forecasted to grow at a steady rate over the next 20 years, the total residential sales is outpaced by non-residential sales by 2045. This reflects PNM's expectation that sales from non-residential EV charging will massively increase as New Mexico policies drive increased adoption.

Figure 32: PNM Territory-Wide EV Sales Forecast



There are several inputs for calibration. The primary input is sales (MWh), and additional inputs include the forecasted number of premises, as well as the market cap. In order to convert the provided sales forecast into a premise count, different sets of assumptions were used for the various rate classes in PNM. Table 19 shows the assumptions used for this process. In addition, Table 19 shows the market cap used for each of the rate classes, which is simply the total number of premises in each rate class.

Table 19: Assumptions Used to Convert Sales into Premise Counts

Rate Class	Annual Vehicle Miles Traveled	kWh per Mile	Fleet Size	Market Cap
R1	13,303	0.346	1	435,229
SP2	28,396	1.56	1	58,592
GP3	28,396	1.56	10	3,157
LP4	28,396	1.56	50	134

An average of 13,303 miles per year per premise was assumed for the residential (R1) rate class, as well as a charging efficiency of 0.346 kWh per mile. For the larger rate classes, specifically SP2, GP3, and LP4, the EV charging sales are assumed to come from medium and heavy duty (MHDV) rather than light-duty vehicles (LDV), and that customers within these rate classes have larger fleet sizes. This is reflected in the higher number of annual vehicle miles traveled, a higher number of kWh per mile needed to charge an MHDV, and a larger fleet size.

Propensity scores were then calibrated to sum to the system-level annual forecast by rate class. These propensities were developed at the premise-level, and subsequently rolled up to the feeder, substation, and zone levels. The feeder-level calibrated forecast is shown for all PNM territory and the Albuquerque, Santa Fe, and Sandoval zones for 2026 and 2031 in Figure 33 and Figure 36.

Figure 33: EV Penetration by Feeder: 2026 and 2031 - PNM Territory

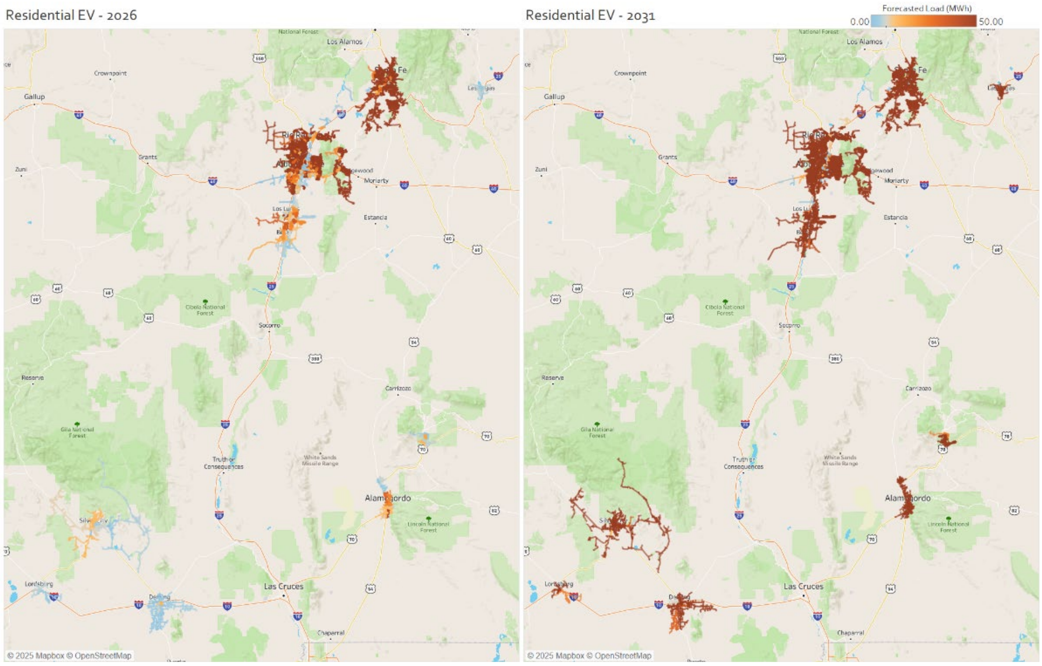
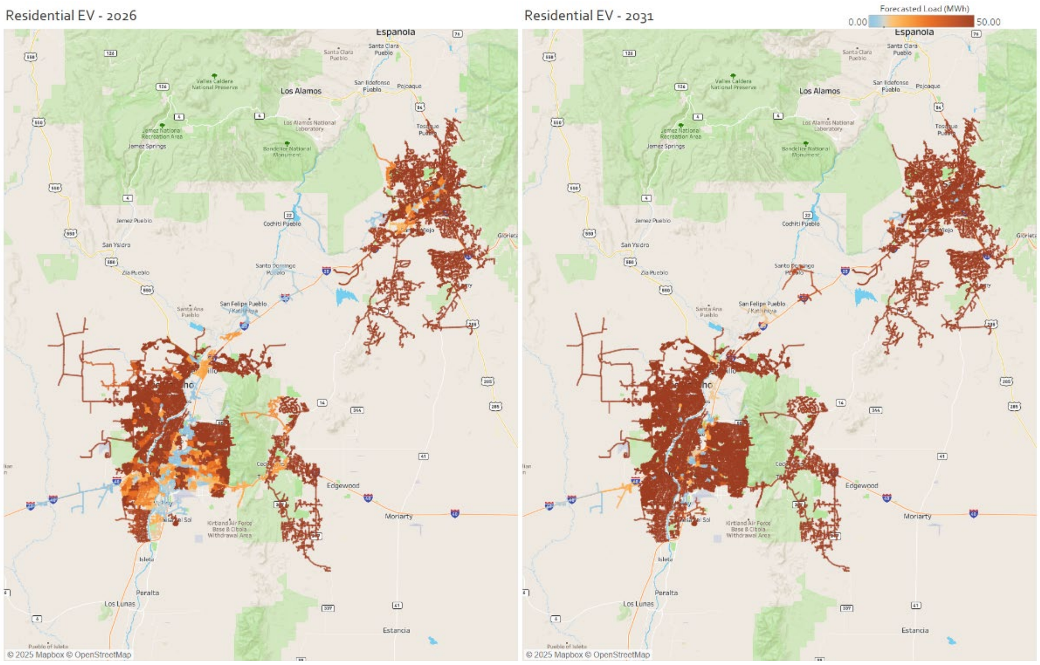


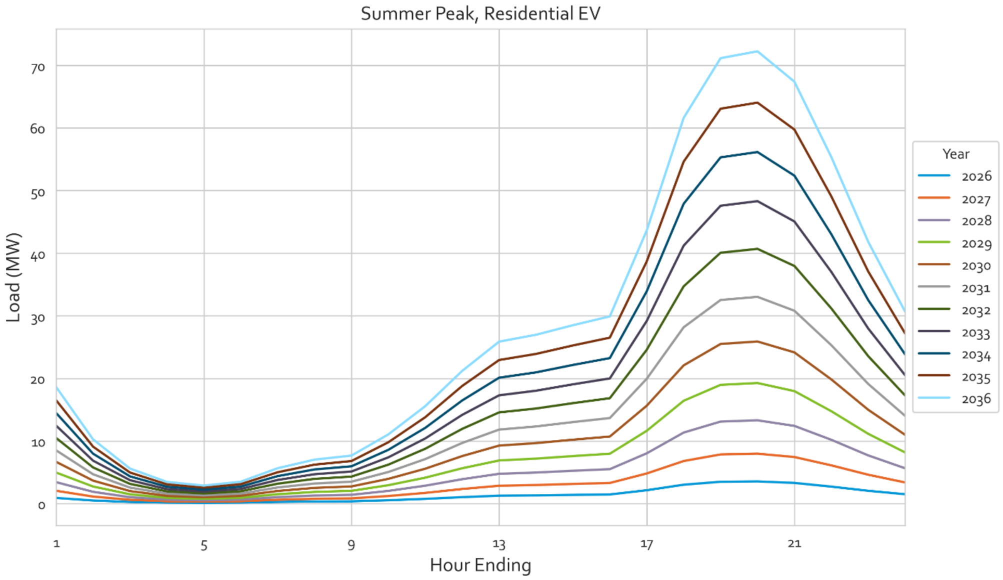
Figure 34: EV Penetration by Feeder: 2026 and 2031 - Albuquerque, Santa Fe, and Sandoval



5.2.3 HOURLY DEMAND FORECAST

The forecasted annual consumption, given in MWh, was then converted into an hourly demand forecast by applying a normalized annual load shape. PNM provided an annual load shape for 20 forecast years[12], which was then collapsed into an average load shape by season and weekday. This average load shape was then applied to the annual forecast MWh to obtain the hourly forecasted demand from EV charging. The summer and winter peak day hourly forecast is shown in Figure 35 and Figure 36.

Figure 35: Forecasted EV – Summer Peak Day: 2025-2035



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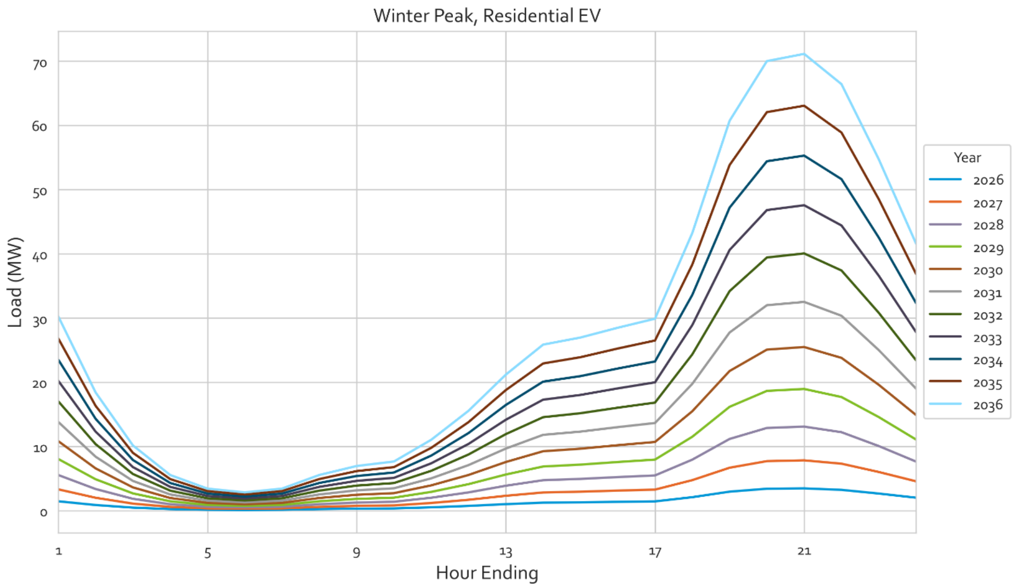
[12] The load shape was consistent with the PNM IRP and originated from participants in PNM's Whole Home Electric Vehicle rate. This could possibly evolve as AMI is rolled out and Time of Use and Critical Peak Pricing is incorporated into PNM's rate design. Benefits of AMI for future modeling include the ability to model EV propensity based on load shape signatures and the ability to develop unmanaged electric vehicle load shapes.

Figure 36: Forecasted EV - Winter Peak Day: 2025-2035



5.3 ADJUSTMENTS FOR LOAD GROWTH FROM EXISTING RESOURCES – EE

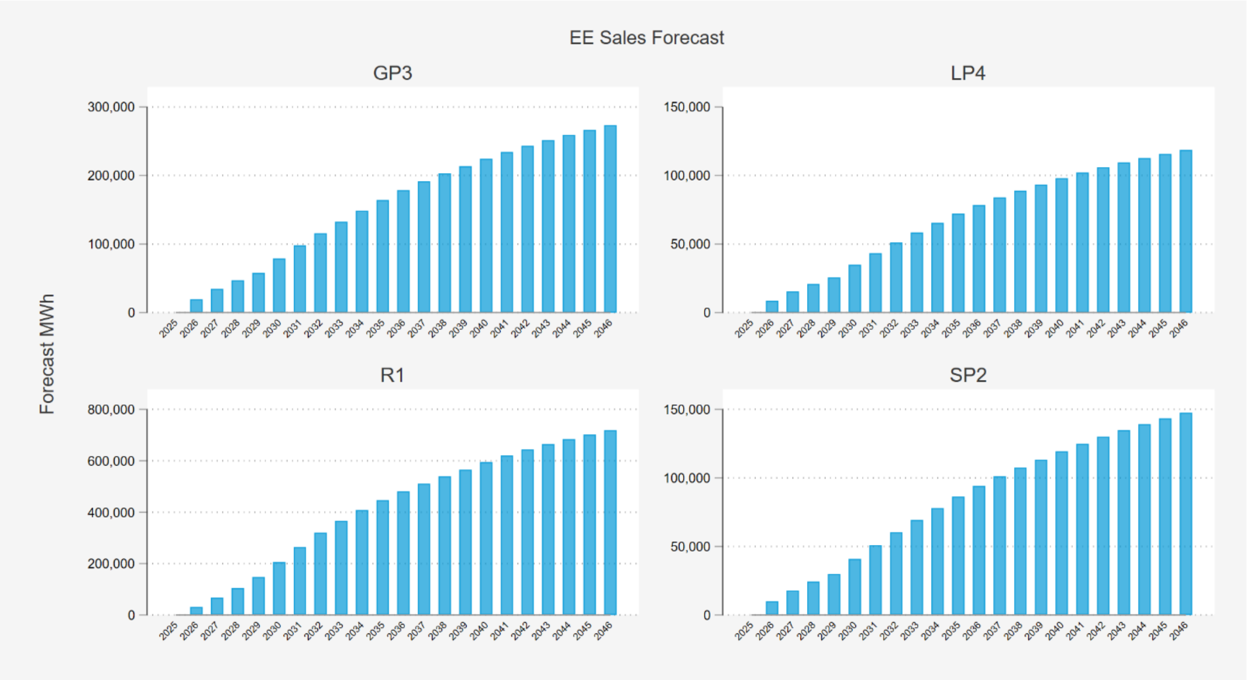
5.3.1 PROPENSITY SCORE DEVELOPMENT

Because there was little adoption data available for EE measures, propensities were developed for future EE measure adoption using premise-level annual gross usage. Within each rate class, the share of total annual gross usage was estimated for each premise, which serves as the propensity score. This was the most reasonable estimate given the granularity of the data available. In practice, EE adoption may be clustered in certain locations, more or less likely for premises with certain building or usage characteristics, etc. Future modeling precision would be improved with incorporation of premise level EE adoption data to better reflect these differences.

5.3.2 CALIBRATION TO SYSTEM LEVEL FORECAST

For this study, PNM provided the system-level forecast of sales (in MWh) by rate class. This forecast is shown in Figure 37, and is incremental to the EE currently installed in 2025.

Figure 37: PNM Territory-Wide EE Sales Forecast



The system-level forecast for each rate class was multiplied by the propensity score to produce the calibrated forecast, as the propensity scores developed are simply shares of total gross annual usage within rate classes. These propensity scores were subsequently rolled up to the feeder, substation, and zone levels. The feeder-level calibrated forecast is shown for all PNM territory and the Albuquerque, Santa Fe, and Sandoval zones for 2026 and 2031 in Figure 38 and Figure 39.

Figure 38: EE Feeder-level Penetration: 2026 and 2031 – PNM Territory

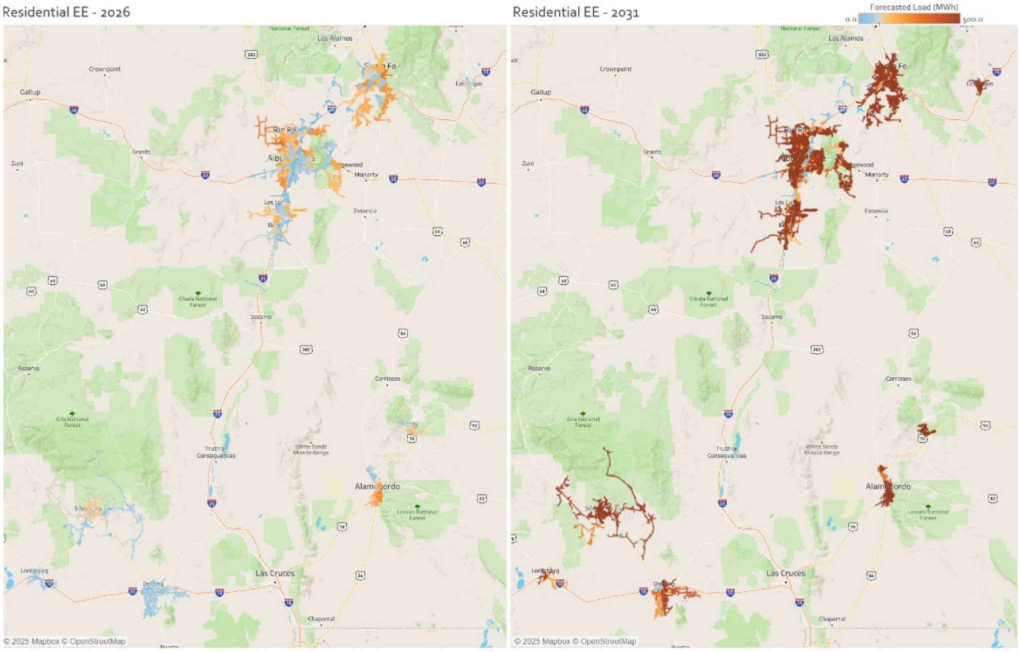
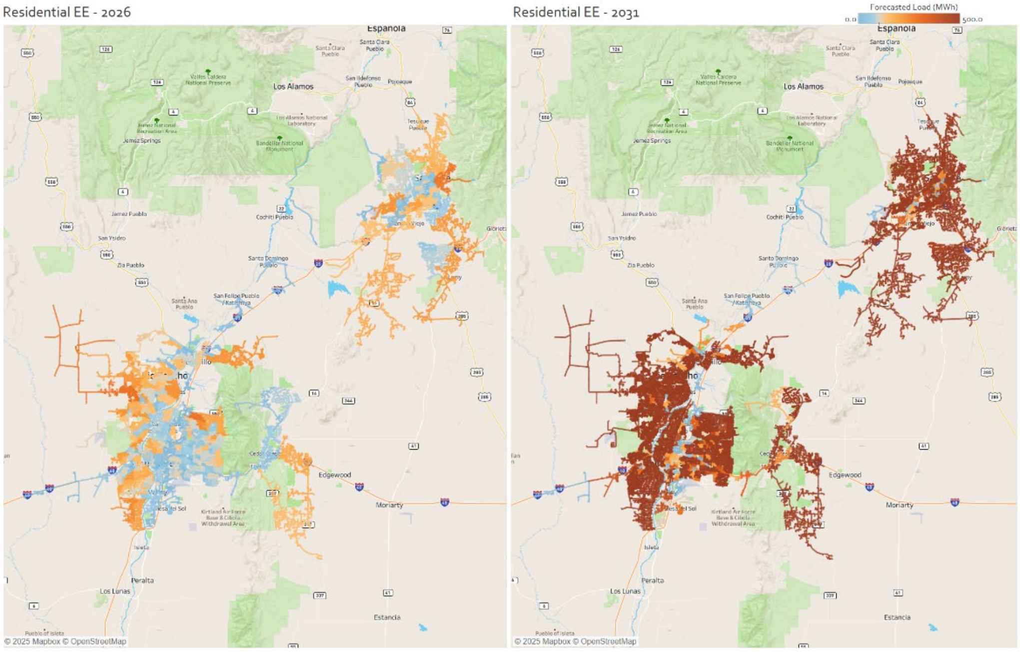


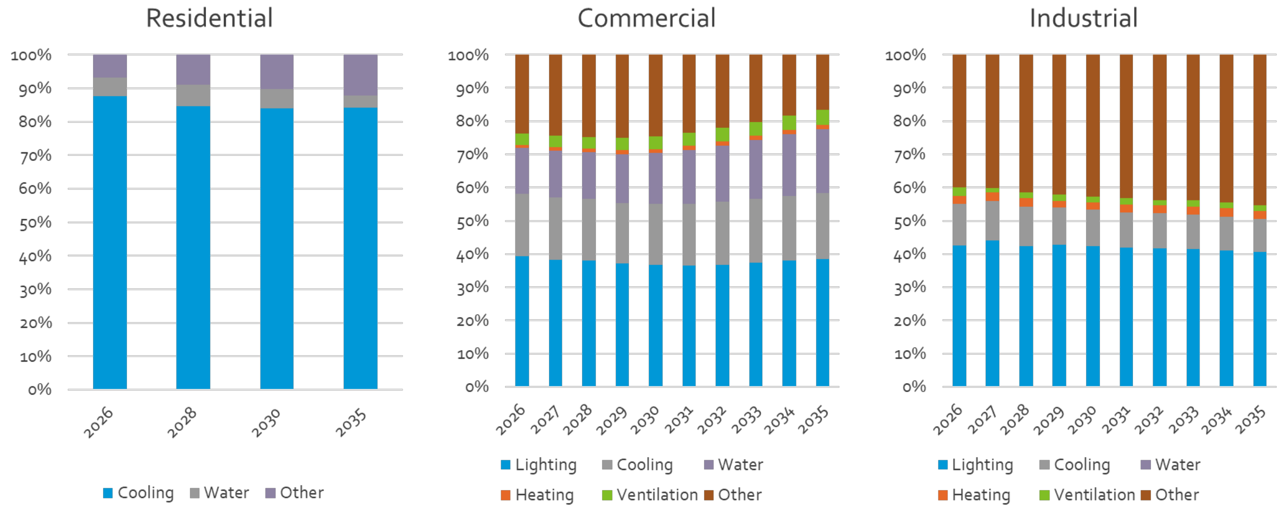
Figure 39: EE Feeder-level Penetration: 2026 and 2031 - Albuquerque, Santa Fe, and Sandoval



5.3.3 Hourly Demand Forecast

The forecasted annual consumption, given in MWh, was then converted into an hourly demand forecast by applying a normalized annual load shape. For EE, a composite, normalized load shape was developed primarily using NREL end use profiles, weighted for each rate class by the savings end use mix developed by the PNM Potential Study, a key input to the EE forecast for the PNM 2026 IRP. Figure 40 summarizes the end use share by year and rate class used to weight load shapes to derive portfolio weighted EE load shapes for the study.

Figure 40: EE Savings Forecast End Use Mix by Rate Class



NREL provides annual load shapes for common residential and non-residential end uses and building types, aggregated to the census tract level. Common end uses included in the aggregated end use profiles include heating, cooling, ventilation, and lighting for a variety of residential and non-residential building types. Substations within the PNM territory were mapped to their corresponding census tract in order to produce a normalized EE load shape unique to the rate class mix and building stock of each substation. The load shapes reflect the building stock in each census tract and the end use mix by rate class of the system wide forecast. As an example, Figure 41 shows the system level normalized residential load shape which reflects the end use mix in Figure 40. In practice the shape and magnitude of the EE modeled load shape for each location reflects:

1. the rate class and end use mix at that location,
2. the census tract end use specific load shapes corresponding to the location,
3. and the system level forecasted EE savings allocated to that location.

As described above, the locational dispersion of the system forecast lacks locational granularity since premise level adoption data was not available to inform how adoption may vary by location, building characteristics, or premise usage patterns. Future modeling precision of the magnitude of locational EE impacts would be improved with incorporation of premise level EE adoption data to better reflect these differences.

Figure 41: System Level Residential EE Load shape

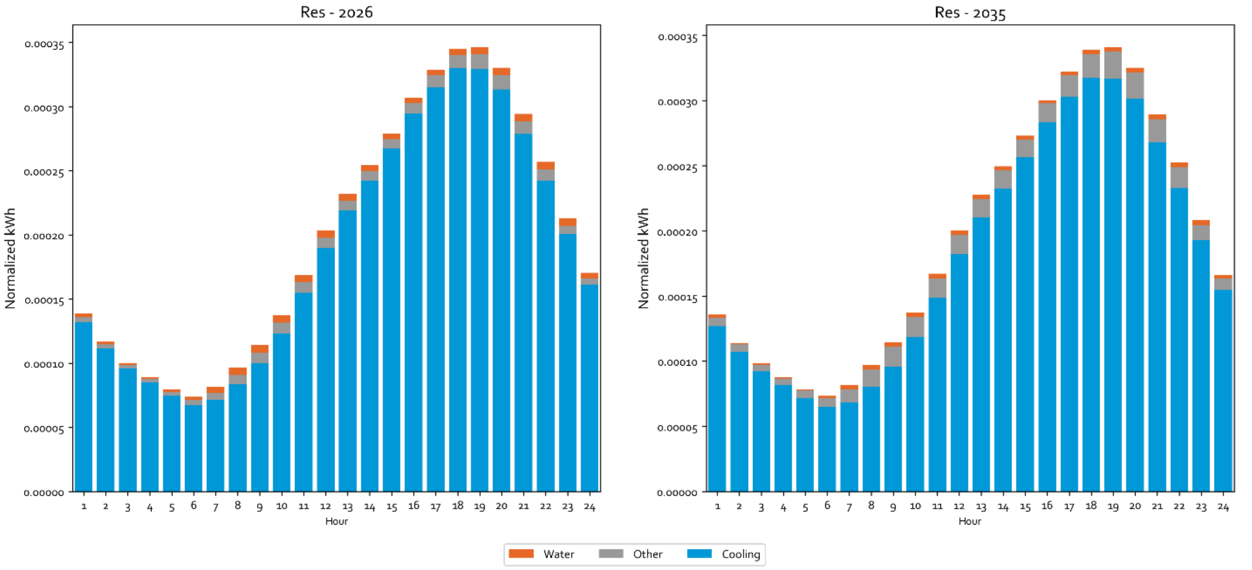


Figure 42: Forecasted EE - Summer Peak Day: 2025-2035

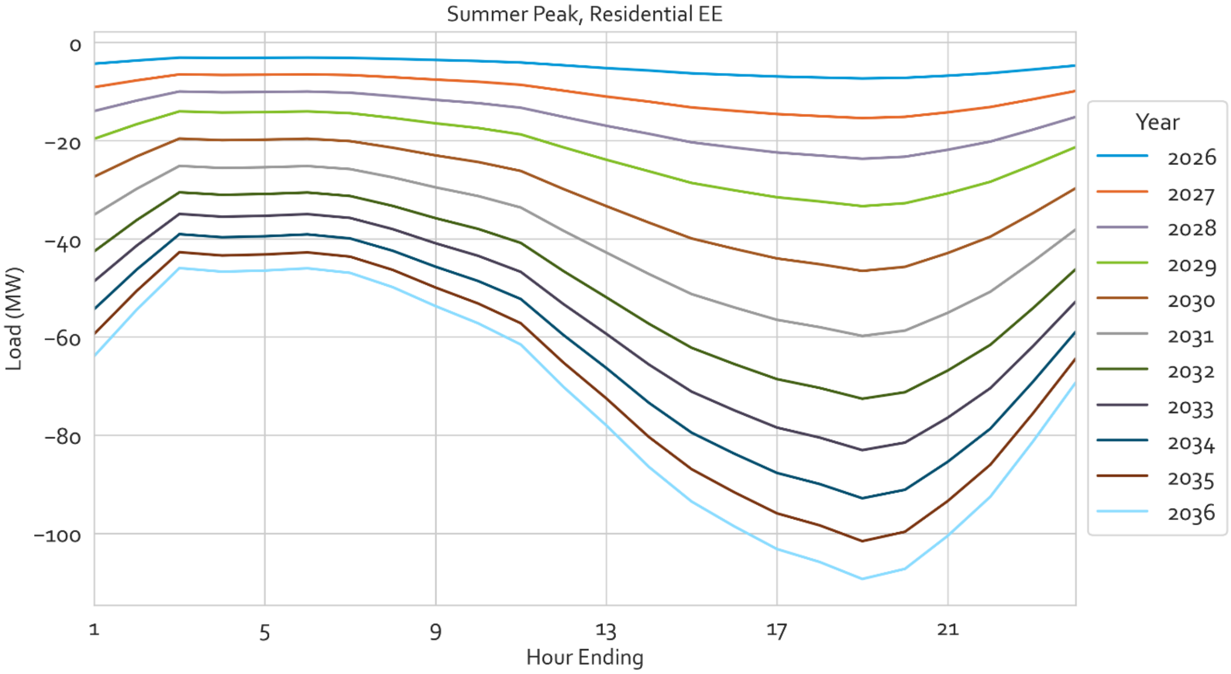
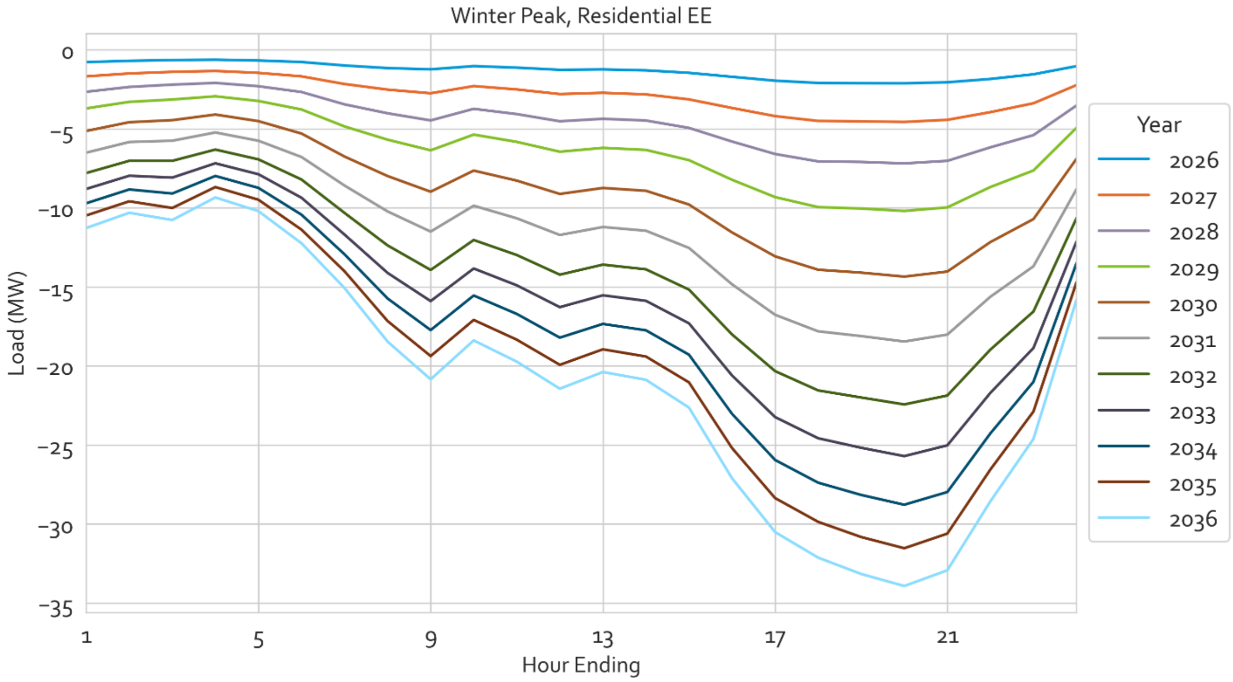


Figure 43: Forecasted EE- Winter Peak Day: 2025-2035



5.4 ADJUSTMENTS FOR LOAD GROWTH FROM EXISTING RESOURCES – BTM PV

Figure 44 shows the methodology used to produce propensity scores for behind-the-meter solar adoption at the premise level. There were several data sources used for BTM solar granular forecast. Historical Photovoltaic (PV) interconnections from 2020-2025 were provided by PNM, as well as front-of-the-meter and BTM solar production by zone for the same time frame. In addition, for the residential rate class, billing data with annual generation (kWh) was provided by PNM. The current penetration of premises with solar is displayed in Table 20.

Figure 44: BTM Solar Granular Forecasting Methodology

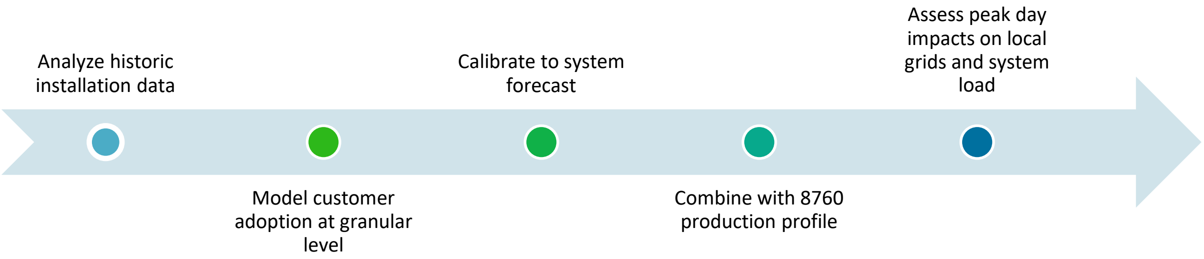


Table 20: Current Penetration of BTM Solar in PNM Territory

Year	Number of Sites	Installed MW
2020	22,793	205
2021	28,809	257
2022	34,807	305
2023	41,457	361
2024	45,106	396
2025 (Q1-Q2)	47,059	417

5.4.1 PROPENSITY SCORE DEVELOPMENT

Figure 45 details the methodology used to develop propensity scores. For BTM solar, propensity scores were produced for each premise using the decision tree model XGBoost. XGBoost classifies a premise as either having solar or not having solar based on a set of premise features, such as the square footage of the home, the age of the home, the annual electricity usage at the premise, and whether the premise already has additional load modifiers.

Figure 45: BTM Solar Propensity Modeling Methodology Overview

STEP 1:
Exploratory Data Analysis

- Analyze customers who have and have not adopted the DER/load modifier in question
- Explore relationship of all possible predictive variables for DER adoption
  - ✓ Correlation
  - ✓ Plots
  - ✓ Bivariate regressions
- Identify the key predictors of adoption
- Identify non-linear patterns

STEP 2:
Machine Learning Model

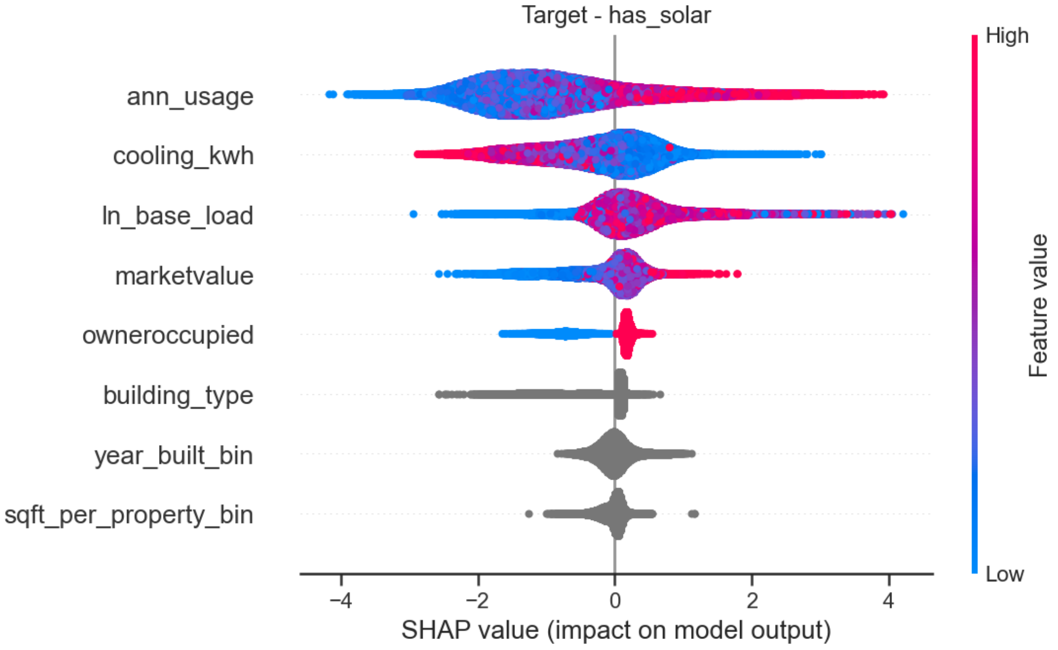
- Split data into training/testing data
- Train Model on predictive features
  - ✓ XG Boost
  - ✓ Model identifies what best predicts the outcome
  - ✓ Captures non-linear and linear relationships
  - ✓ The models iterates and learns, improving with each iteration
- Models are assessed using the testing data

STEP 3:
Apply to all Customers

- Predict likelihood of adoption (today) for each premise and DER/Load Modifier – aka propensity score
- The predictions factor in customer specific information and helps us distinguish early adopters from late adopters
- The propensity scores are scaled so the sum of the adoption probabilities for each year equals the system level forecast (Calibration)
- When aggregated by feeder, it provides the expected adoption by year and DER for each feeder

Figure 46 shows the most important features in predicting BTM solar adoption. Among these features are the gross annual usage and cooling load of the customer, as well as property-specific features such as the building type (e.g., single-family, multi-family, etc.), the square footage, the year built, and whether the property is owner occupied or not. Typically, higher gross annual usage, high square footage, and newer homes impact the propensity model positively.

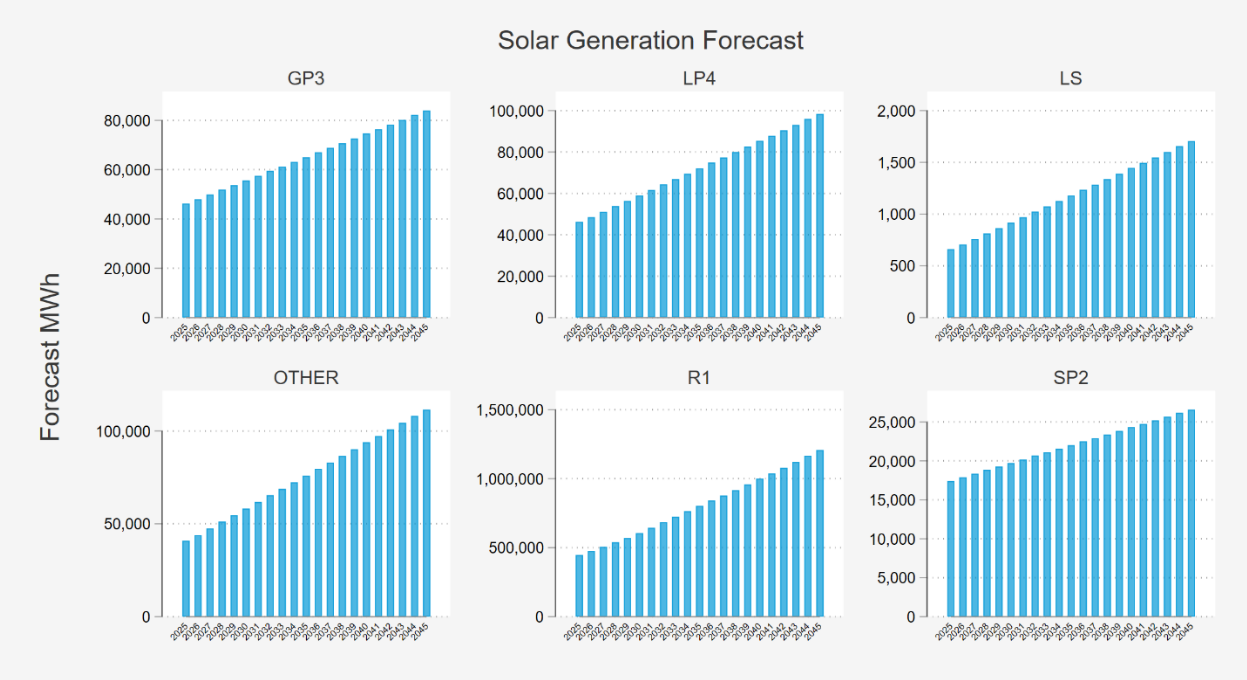
Figure 46: BTM Solar Propensity Model SHAP Feature Importance



5.4.2 CALIBRATION TO SYSTEM LEVEL FORECAST

While the propensity scores dictate where predicted, future generation from solar occurs, the total magnitude of annual generation is primarily driven by the system-level forecast. For this study, PNM provided the system-level forecast of generation (in MWh) by rate class. This forecast is shown in Figure 47. Propensity scores were then calibrated to sum to the system-level annual forecast by rate class.

Figure 47: PNM Territory-Wide Solar Production Forecast



There are several inputs for calibration. The primary input is energy (MWh), and additional inputs include the forecasted number of premises, as well as the market cap. In order to convert the provided generation forecast into a premise count, different sets of assumptions were used for the various rate classes in PNM. Table 21 shows the assumptions used for this process. In addition, Table 21 shows the market cap used for each of the rate classes, which is simply the total number of premises in each rate class.

Table 21: Assumptions Used to Convert Production into Premise Counts

Rate Class	Average Capacity (kW)	MWh/MW	Market Cap
R1	5.15	1,225	435,229
Other	58.04	222	71,905
SP2	18.28	98	58,592
GP3	92.49	169	3,157
LP4	523.71	172	134
LS	200	172	6

In order to convert the forecasted generation into a count of premises with solar, the generation forecast was first scaled by the average annual generation (MWh) per MW of capacity to estimate the forecasted installed capacity. The average capacity installed per premise was calculated using historic interconnection data. For large solar, the solar production data was summed to estimate the annual production in MWh, and for small solar – both residential and non-residential – billing data was used to estimate the annual MWh.

Propensity scores were then calibrated to sum to the system-level annual forecast by rate class. These propensities were developed at the premise-level, and subsequently rolled up to the feeder, substation, and zone levels. The feeder-level calibrated forecast is shown for all PNM territory and the Albuquerque, Santa Fe, and Sandoval zones for 2026 and 2031 in Figure 48 and Figure 49.

Figure 48: BTM Solar Feeder-level Penetration: 2026 and 2031 – PNM Territory

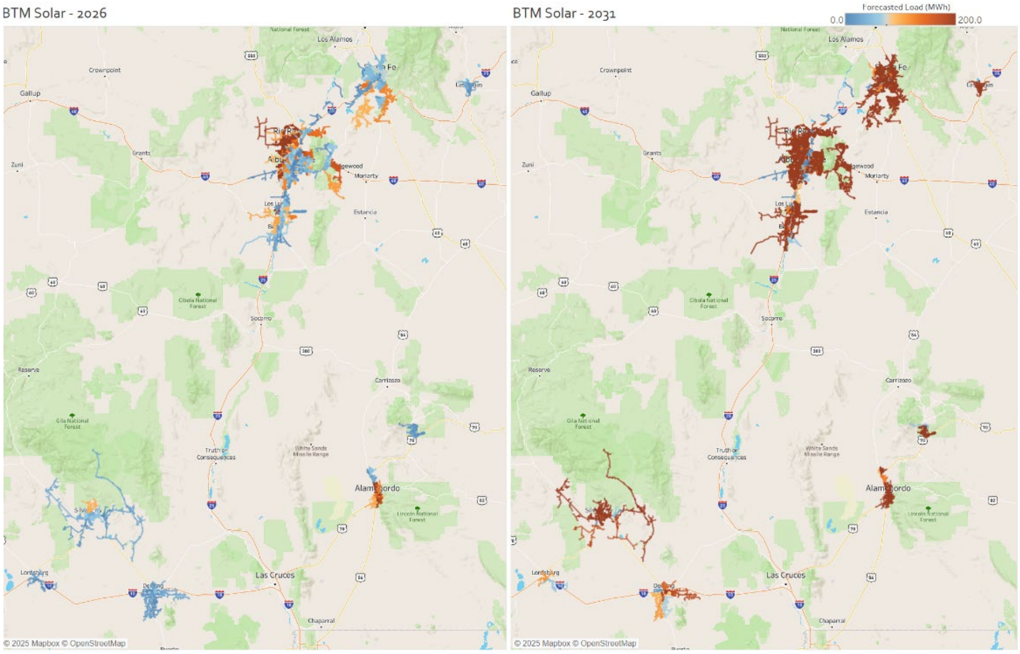
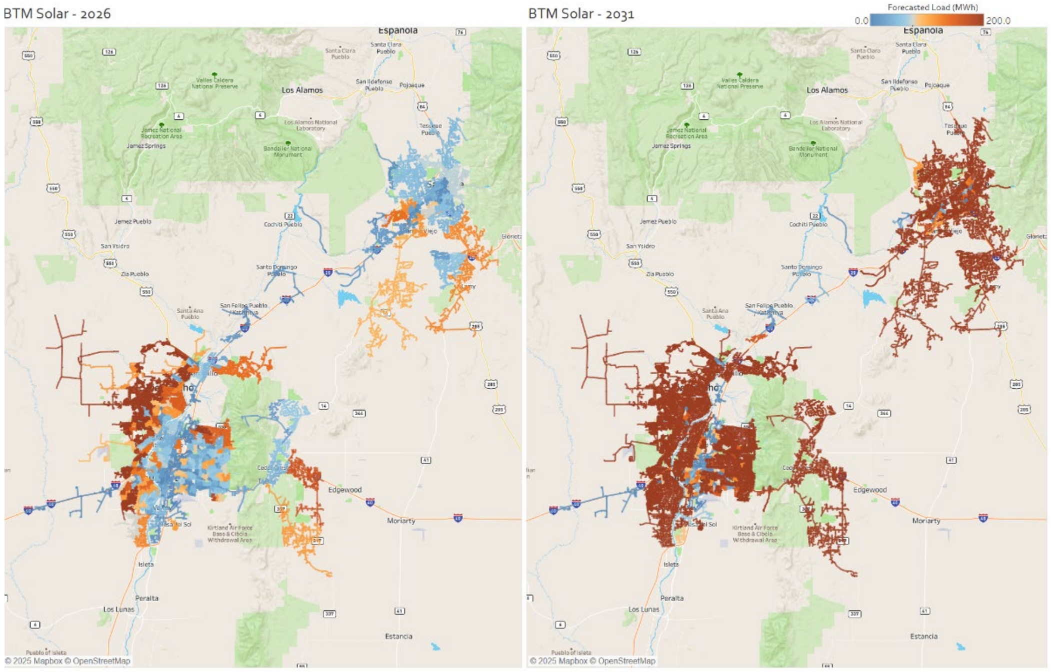


Figure 49: BTM Solar Feeder-level Penetration: 2026 and 2031 - Albuquerque, Santa Fe, and Sandoval



5.4.3 HOURLY DEMAND FORECAST

The forecasted annual generation from BTM solar, given in MWh, was then converted into an hourly demand forecast by applying a normalized annual load shape. For large solar, the historic generation profiles provided were weather-normalized and averaged, weighted by the respective nameplate capacities. The large solar normalized load shapes were de-rated to produce small non-residential and residential solar load shapes. The summer and winter peak day hourly forecasts are shown in Figure 50 and Figure 51.

Figure 50: Forecasted BTM Solar - Summer Peak Day: 2025-2035

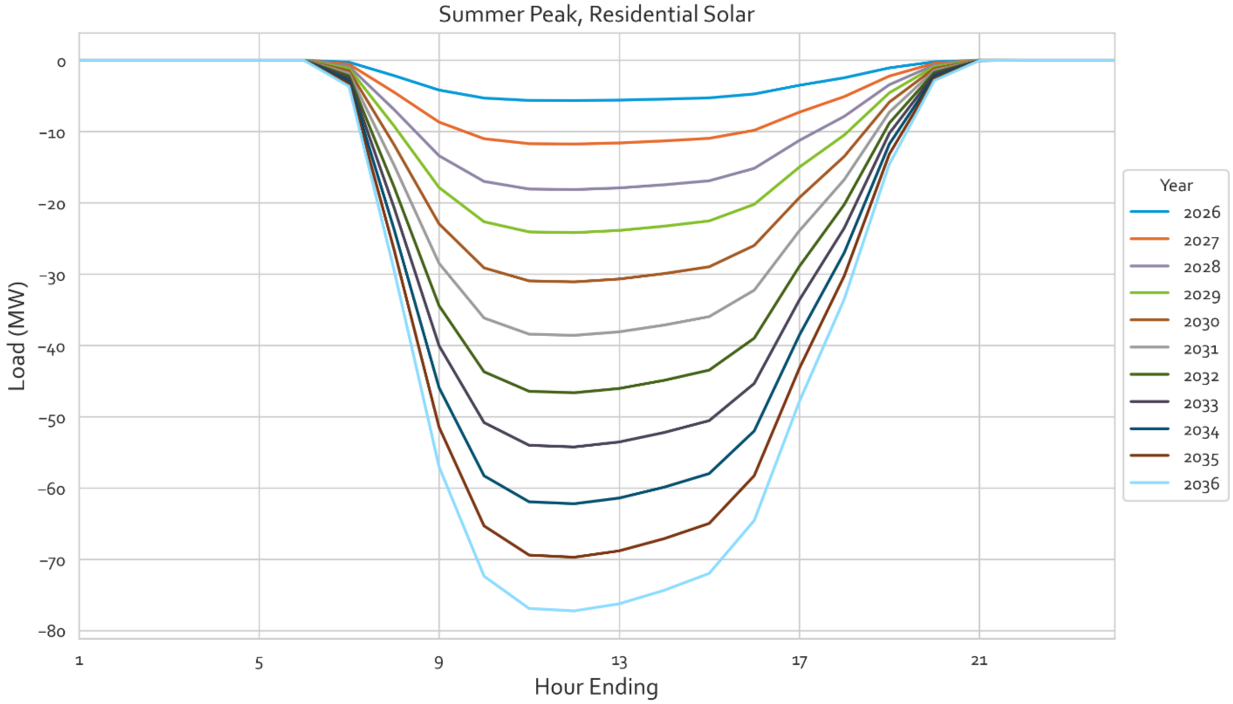
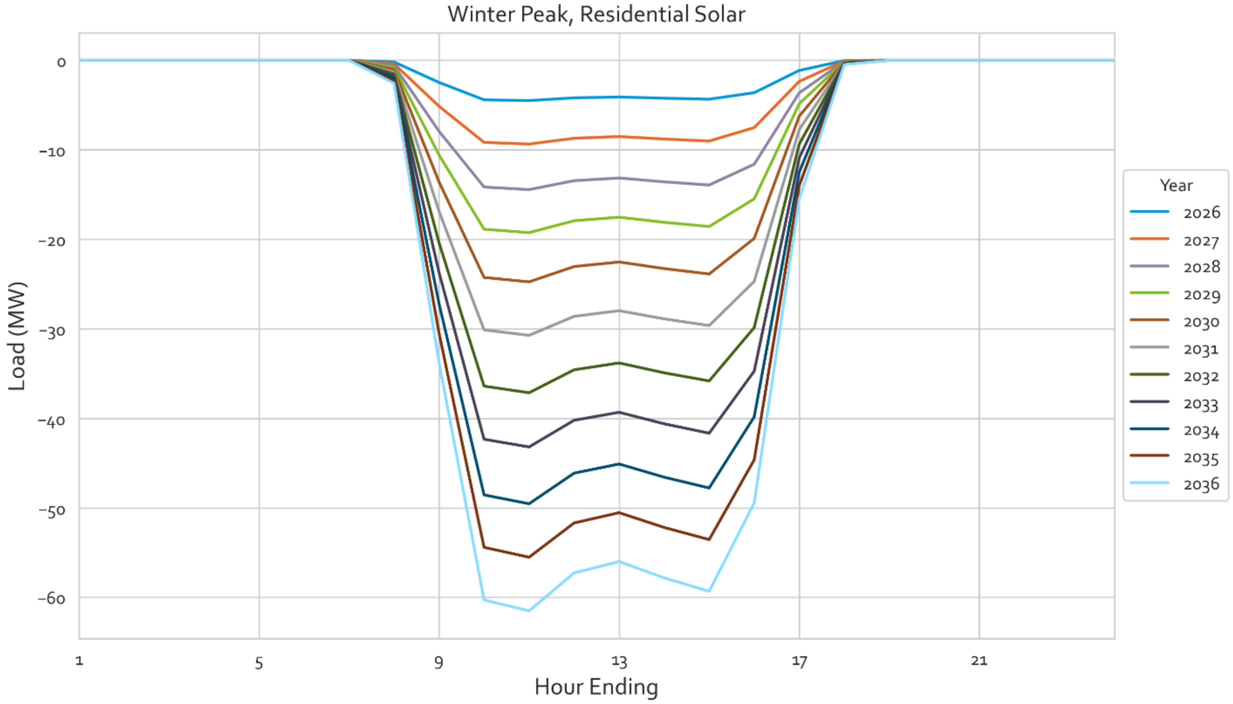


Figure 51: Forecasted BTM Solar - Winter Peak Day: 2025-2035



5.5 ADJUSTMENTS FOR LOAD GROWTH FROM EXISTING RESOURCES – FTM PV

Figure 52 shows the methodology used to produce forecasted Front-the-meter (FTM) solar at feeder level. The FTM forecast consists of two components: (1) existing FTM resources, which are assumed to continue operating throughout the forecast period, and (2) planned community solar. There were several data sources used for FTM solar granular forecast. PNM provided historical PV interconnection data for 2020–2025, as well as zonal FTM solar production for the same period. All 22 historical FTM sites were installed on or before 2019 and collectively total 188.32 MW of capacity. Additionally, PNM supplied a queue of community solar projects, including planned in-service dates and projected MW capacities. A summary of queue community solar projects is shown in Table 22**.**

Figure 52: FTM Solar Granular Forecasting Methodology

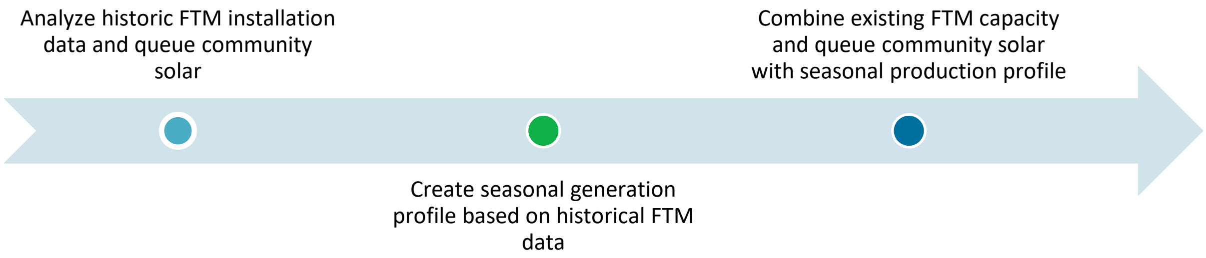


Table 22: Queue Community Solar in PNM Territory

Year	Cumulative Projects (Feeder-Level)	Cumulative Installed MW
2025	6	28.9
2026	30	124.4
2027	31	129.1

The historic generation profiles provided were weather-normalized and averaged, weighted by the respective capacities within each zone and for each season. The normalized load shapes are assumed to remain constant across years. Both the existing FTM capacity and the queue CS capacity were converted into an hourly forecast by applying the normalized seasonal FTM production profile. The summer and winter peak day hourly forecasts are shown in Figure 53 and Figure 54. Because there is no queue CS capacity after 2027, the 2027 profile and all subsequent years share the same shape.

Figure 53: Forecasted FTM Solar - Summer Peak Day: 2025-2035

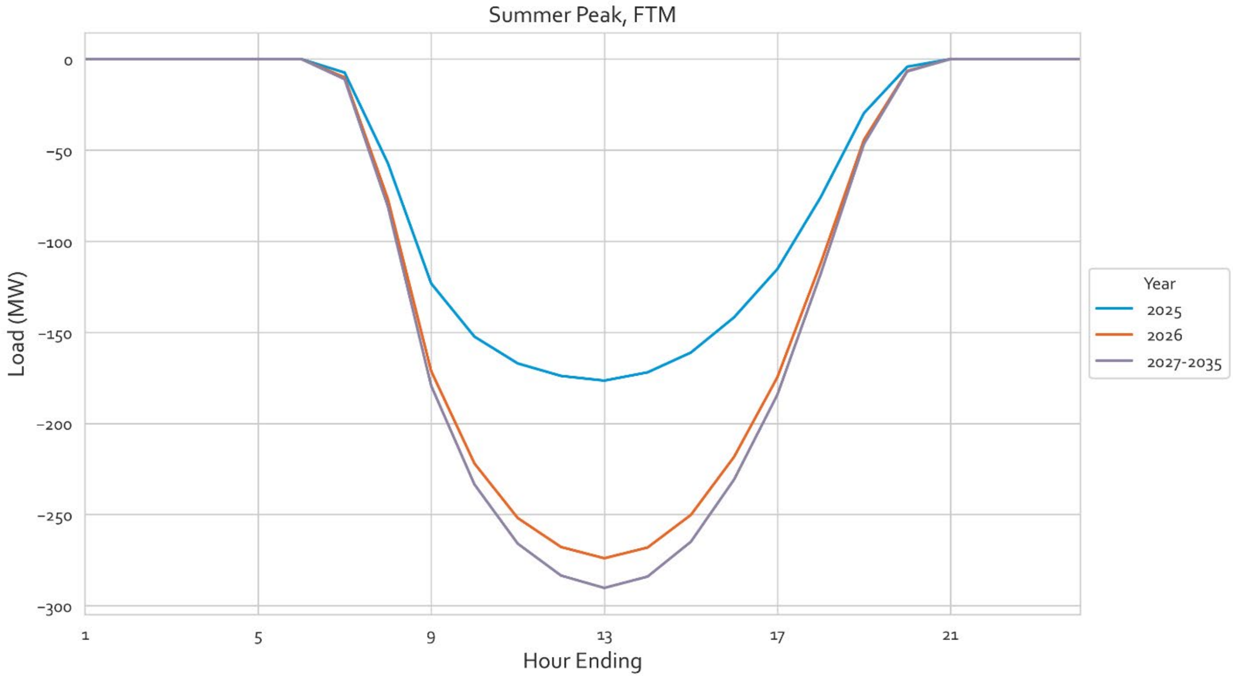
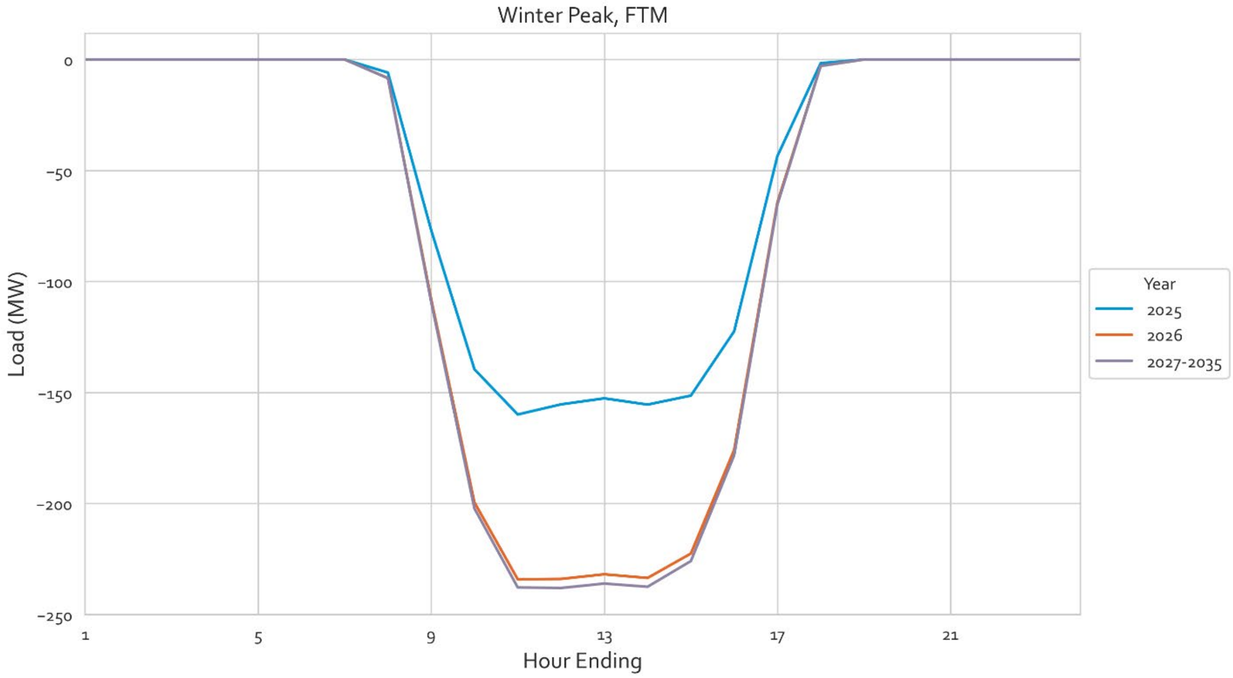


Figure 54: Forecasted FTM Solar - Winter Peak Day: 2025-2035



APPENDIX B – ECONOMETRIC MODELS USED TO ESTIMATE HISTORICAL GROWTH

The econometric models were purposefully designed to both estimate historical load growth in percentage terms and allow us to weather normalize loads for 1-in-2 and 1-in-10 weather peaking conditions.

The key to this process was to model the natural log of the daily peak loads as the dependent variable and include year-specific coefficients to estimate the percent change in loads, after controlling for other factors. By using the natural log as the dependent variable, all of the explanatory variables reflect the percent change in load associated with a unit change in the independent variable.

The regressions were estimated on the highest 150 local peak days for each analysis year in the 2020 to 2024 timeframe for each location. The goal was to include a sufficient number of days that reflected peaking conditions for each year. The number of observations by location varies slightly because of differences in the amount of data available and because peaks occurring on weekends or holidays were excluded. The model estimated daily peaks as a function of weather interacted with day of week, month, and historical year. Weather was included using a process that avoids assumptions about the type of relationship between weather and load. Rather than assume a constant linear relationship, the weather data is split into equally sized bins and a separate relationship is estimated for different temperature ranges, also known as a spline regression. All models were estimated using time series methods to take into account auto-correlation.[13]

Figure 55 illustrates the model output for one location. A separate model was estimated for each substation transformer and feeder. The model explained 98.8% of the variation and, more importantly, produced estimates of the percent change in loads—the load growth—relative to 2020, after controlling for weather, day of week, and other factors. The coefficient on the year term represents annualized percent growth (in this case of 0.2%). The growth trend and the amount of year-to-year variation differ by location and are central to developing the probabilistic load forecasts. In addition, the confidence bands for the historical growth estimates are linked to the explanatory power of the models. When explanatory power is high, confidence bands are tight. When explanatory power is lower, confidence bands are broader.

The estimates of year-to-year historical load growth also were used to assess the degree to which growth patterns are related to each other, that is, the degree to which growth in the prior year predicts growth in the following year, technically known as auto-correlation. Each individual site had a limited

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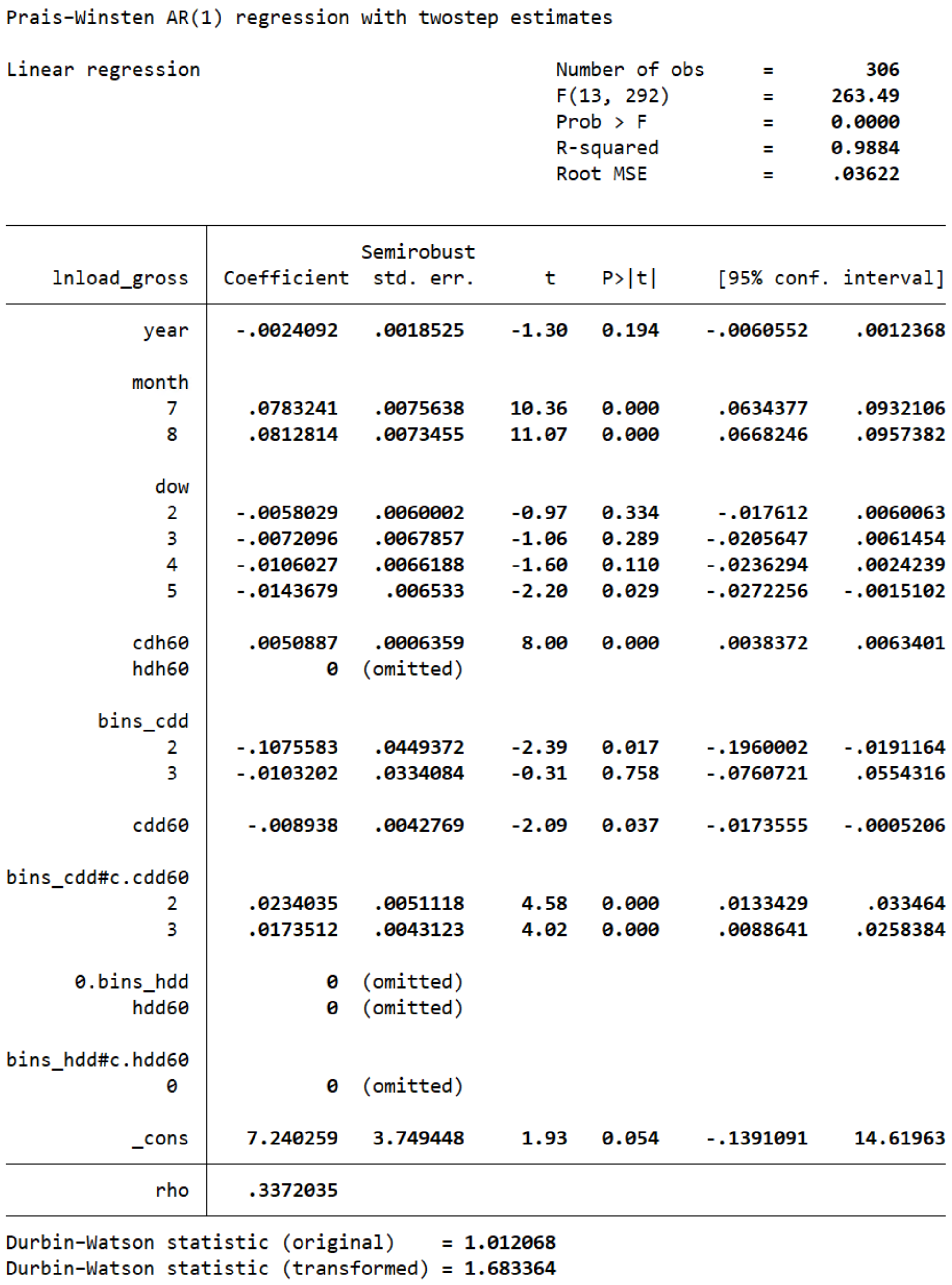
[13] We relied on an iterative feasible GLS model with first order auto-correlation. Other time series options—such as ARIMA and the Newey-West model—do not handle gaps in the time series as easily. All options, however, produce consistent estimates.

number of individual year growth estimates—five years at most—so the estimate of auto-correlation was developed across all sites.

Figure 55: Example Load Growth Econometric Model



```
Prais-Winsten AR(1) regression with twostep estimates

Linear regression                               Number of obs     =        306
                                                F(13, 292)        =     263.49
                                                Prob > F          =     0.0000
                                                R-squared         =     0.9884
                                                Root MSE          =     .03622

------------------------------------------------------------------------------
             |             Semirobust
 lnload_gross | Coefficient  std. err.      t    P>|t|     [95% conf. interval]
-------------+----------------------------------------------------------------
        year |  -.0024092   .0018525    -1.30   0.194    -.0060552    .0012368
             |
       month |
          7  |   .0783241   .0075638    10.36   0.000     .0634377    .0932106
          8  |   .0812814   .0073455    11.07   0.000     .0668246    .0957382
             |
         dow |
          2  |  -.0058029   .0060002    -0.97   0.334     -.017612    .0060063
          3  |  -.0072096   .0067857    -1.06   0.289    -.0205647    .0061454
          4  |  -.0106027   .0066188    -1.60   0.110    -.0236294    .0024239
          5  |  -.0143679    .006533    -2.20   0.029    -.0272256   -.0015102
             |
       cdh60 |   .0050887   .0006359     8.00   0.000     .0038372    .0063401
       hdh60 |          0  (omitted)
             |
    bins_cdd |
          2  |  -.1075583   .0449372    -2.39   0.017    -.1960002   -.0191164
          3  |  -.0103202   .0334084    -0.31   0.758    -.0760721    .0554316
             |
       cdd60 |   -.008938   .0042769    -2.09   0.037    -.0173555   -.0005206
             |
bins_cdd#c.cdd60 |
          2  |   .0234035   .0051118     4.58   0.000     .0133429     .033464
          3  |   .0173512   .0043123     4.02   0.000     .0088641    .0258384
             |
  0.bins_hdd |          0  (omitted)
       hdd60 |          0  (omitted)
             |
bins_hdd#c.hdd60 |
          0  |          0  (omitted)
             |
       _cons |   7.240259   3.749448     1.93   0.054    -.1391091    14.61963
-------------+----------------------------------------------------------------
         rho |   .3372035
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    = 1.012068
Durbin-Watson statistic (transformed) = 1.683364
```

APPENDIX C – TABLE OF ACRONYMS

Table 23 lists the acronyms used in this report and their meaning.

Table 23: Acronyms and Meanings

Acronym	Meaning
BTM	Behind-the-meter
CS	Community Solar
CT	Contingency
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resource
EE	Energy Efficiency
EV	Electric Vehicle
FTM	Front-the-meter
HE	Hour Ending
IRP	Integrated Resource Plan
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LDV	Light-Duty Vehicles
MHDV	Medium- and Heavy- Duty Vehicles
MVA	Megavolt-Amperes
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
NWA	Non-Wire Alternative
O&M	Operation and Management
PNM	The Public Service Company of New Mexico
PUC	Public Utility Commission
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
WHEV	Whole-Home Electric Vehicle