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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 317	)	**Case No. 25-00082-UT**
EL PASO ELECTRIC COMPANY, Applicant.	)	

DIRECT TESTIMONY

OF

ENEDINA SOTO

ON BEHALF OF

EL PASO ELECTRIC COMPANY

MARCH 2026

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EL PASO ELECTRIC COMPANY
TESTIMONY DIRECT OF
ENEDINA SOTO

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.

A. My name is Enedina Soto. My business address is 100 N. Stanton Street, El Paso, Texas 79901-1341.

Q2. BY WHOM ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company").

Q3. WHAT IS YOUR CURRENT POSITION WITH EPE?

A. I am the Manager of the Load Research & Data Analytics Department.

Q4. HOW LONG HAVE YOU BEEN EMPLOYED BY EPE?

A. I have been employed by EPE since March of 2010.

Q5. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS MANAGER?

A. I am responsible for the economic forecasting and load research functions. I manage and direct the activities of the Load Research & Data Analytics Department, including the development of load research studies and reports, allocation factors, weather normalization, and the long-term customer, energy, and load forecasts.

Q6. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. After earning my master's degree, I was hired by EPE as a Load Research Specialist, where my responsibilities included the derivation of the energy and demand allocation factors, the design and implementation of load research samples, the design of the Residential Appliance Saturation Survey, and the completion of schedules for regulatory rate case filings. In 2020, I was promoted to Principal-Economist where my responsibilities included the development of the long-term energy, demand, and customer forecast, as well as the weather normalization model. Shortly thereafter, I was promoted to my current position as Manager of the Load Research & Data Analytics Department in 2021.

Q7. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from The University of Texas at El Paso with a Bachelor of Business Administration in Economics in 2008, and a Master of Science in Economics in 2010.

Q8. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have filed testimony with the Public Utility Commission of Texas.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q9. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the load research function and its role in gathering the energy and demand data necessary for assigning costs to jurisdictions and to rate classes for the development of tariffs; describe and support EPE's proposed weather normalization adjustments; present and support the results of EPE's most recent system loss study; as well as to provide EPE's forecasted sales and demand. I also support two compliance issues: (1) the allocation factors assuming the reopening of Rate No. 07 - City and County Service to new customers and (2) the load data for Rate No. 42 – Experimental Electric Vehicle Charging Rate. The Company's current energy and demand forecast summary is provided in Exhibit ES-6.

Q10. WHAT SCHEDULES DO YOU SPONSOR?

A. I am sponsoring Schedules M-3, P-1, P-6, P-9, and Q-1.

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III. LOAD RESEARCH

A. LOAD STUDIES

Q11. PLEASE DESCRIBE THE LOAD RESEARCH PROGRAM AT EPE.

A. EPE's Load Research & Data Analytics Department conducts census and sample studies of New Mexico and Texas customer energy and demand usage by rate class to estimate class coincident peak demand, maximum class demand, and non-coincident maximum demand. EPE witness Adrian Hernandez uses this data to allocate costs to jurisdictions and rate classes, and EPE witness Manny Carrasco uses this data to develop rates based on energy and demand usage.

Q12. CAN YOU DESCRIBE A CENSUS STUDY?

A. Yes. A census study, or a 100 percent-metered study, indicates that every customer in that rate class is being measured with an Interval Data Recorder ("IDR") meter or through EPE's Advanced Metering System ("AMS"). These studies are typically performed on single customer rate classes or rate classes with a low number of customers. For example, EPE's New Mexico Large Power Service rate has about 24 customers, all of which have either IDR or AMS meters. Load studies for rate classes that are based on a census study are shown on Schedule P-1(b). Data for census studies are shown in total form; there is no sampling error in developing the total class load. The census data presented in Schedule P-1(b) is based on calendar

month information. Therefore, due to differences between calendar months and billing months, the data will not exactly match billing data.

Q13. FOR WHICH EXISTING RATE CLASSES IN NEW MEXICO DOES EPE CURRENTLY UTILIZE A CENSUS STUDY?

A. New Mexico rate classes that are evaluated using a census study are as follows:

- Rate 09 - Large Power Service;
- Rate 10 - Military Research and Development Service;
- Rate 26 - University Service; and
- Rate 29 - Large Power Interruptible Service.

Q14. CAN YOU DESCRIBE A SAMPLE STUDY?

A. Yes. Sample studies are performed on rate classes that have a large number of customers. Historically, for these larger rate classes, it has not been economically feasible to install IDR meters on every customer. For example, the load study for the New Mexico Residential Service rate class is a sample study due to the large number of customers in the rate class. With over 97,000 New Mexico Residential customers as of September 30, 2025, it would not have been economically feasible to install IDR meters on all customers in this class. With the deployment of AMS (which was completed in 2025 in New Mexico), all sample studies for the Base

Period were estimated using data from the AMS meters. The adoption of AMS has increased the availability of data; however, there will always be missing data due to customer opt-outs and possible data loss. For this reason, EPE will continue to rely on sampling when developing load studies for the larger rate classes but will transition to using larger sample sizes and will leverage the available data. The sample study data is shown in Schedule P-1b.

Q15. HAS EPE EVALUATED THE FEASIBILITY OF TRANSITIONING FROM SAMPLE-BASED LOAD STUDIES TO POPULATION-BASED LOAD STUDIES FOR THE CURRENT RATE CASE?

A. Yes. A population-based approach would indicate that every customer in that rate class is included in the load study. EPE explored the feasibility of using a population-based approach by leveraging all available AMS data for the New Mexico jurisdiction for the Base Period. The analysis compared six key metrics between the two approaches: average energy per customer, average coincident demand per customer, average maximum class demand per customer, average non-coincident demand per customer, class load factor, and class coincidence factor. The comparison is provided in Exhibit ES-1. The analysis shows that the population-based approach is consistent with the traditional sample-based results.

Based on this analysis, EPE elected to continue using a sample-based

approach. This decision was made with confidence that the sample is representative of the population and offers advantages in terms of computational efficiency, reduced processing time, resource optimization, and transparency.

Q16. ARE THERE ANY CONCERNS WITH USING POPULATION-BASED LOAD STUDIES IN THE CURRENT BASE RATE CASE?

A. Yes. Because the AMS rollout had not been completed at the start of the Base Period, complete data is not available for all customers. Also, because AMS meters were installed by geographic region, entire neighborhoods may not be represented at various timeframes throughout the Base Period.

In addition, the Load Research team validates the data used in computing the sampled load studies. Reviewing and validating data for the entire population within a rate class is much more resource intensive.

Q17. WILL EPE USE POPULATION-BASED LOAD STUDIES IN FUTURE FILINGS?

A. Not at this time. As previously mentioned, due to customer opt-outs from AMS and possible data loss, full population data may not be available. However, EPE intends to leverage AMS data by incorporating the use of larger sample sizes to calculate the key metrics in its load studies for future filings.

Q18. FOR WHICH EXISTING RATE CLASSES IN NEW MEXICO DOES EPE CURRENTLY UTILIZE A SAMPLE STUDY?

A. The following rate classes in New Mexico are sampled:

- Rate 01 - Residential Service;
- Rate 03 - Small General Service;
- Rate 04 - General Service;
- Rate 05 - Irrigation Service;
- Rate 07 – City and County Service;
- Rate 08 – Water, Sewage, Storm Sewage Pumping or Sewage Disposal rate; and
- Rate 25 - Outdoor Recreational Lighting.

Q19. WHAT ARE THE PROCEDURES EPE USES TO DEVELOP A SAMPLE DESIGN?

A. EPE uses a stratified random sample process to develop the sample design. The stratified random sample process is composed of the Dalenius-Hodges stratification procedure and the Neyman allocation methodology. The Dalenius-Hodges procedure categorizes each customer into predetermined energy or demand blocks and calculates stratum boundaries based on the frequency of customers per block.

It is important that each customer selected for the sample is in the appropriate strata to ensure an accurate weighted average. The Neyman allocation method is then used to calculate the optimal sample size and to allocate samples between the strata. These methods make use of available data to build efficient and cost-effective sample designs.

Q20. WHAT DOES EPE DO TO COMPLETE THE DEVELOPMENT OF A SAMPLE STUDY AFTER IT IS DESIGNED?

A. After the steps described previously are completed, EPE randomly selects customers from each rate class being sampled and installs survey equipment at each customer's premises, which includes either an IDR or AMS meter. EPE's Meter Testing Department maintains the IDR meters and performs a monthly translation of the data. The Meter Testing Department screens data to ensure the accuracy and validity of the IDR meter readings. AMS data is validated by the Meter Data Management System ("MDMS") on a daily basis. The Load Research & Data Analytics Department performs data analysis on the interval data to identify possible data errors. Data within a normal tolerance range are used in the load study calculations.

For the analysis, a "typical customer" for each study is used for data comparison. The data for each account is collected on a continuous basis with IDR

meters read monthly. For AMS metering, residential meters are read every fifteen minutes and commercial meters are read every five minutes. The data is collected by the AMS system every four hours. After the data is validated, it is merged into the Load Research database which is updated every other day. Accounts in each stratum are then averaged, producing a stratum average. Each stratum average is then multiplied by the stratum weighting factor to develop the class weighted average. The strata weighting factors are the population customers in each stratum as a percentage of the total population for the entire rate class at the time the sample is designed. The weighted average represents a typical customer for each sampled rate class.

Q21. WHAT PROCESS DOES EPE USE TO KEEP THE LOAD STUDIES CURRENT?

A. EPE aims to re-stratify its sample studies and implement new samples every three to five years. The most recent samples were designed in the summer of 2023 and implemented in February 2024. Re-stratification uses the Dalenius-Hodges and Neyman Allocation techniques to derive a new sample design and select a new random sample for each sampled rate class. For the most current samples, AMS meters were installed instead of the usual IDR sample.

For census studies, the customer composition of each rate class is updated every month to ensure full representation.

B. DEVELOPMENT OF JURISDICTION AND RATE CLASS ALLOCATION FACTORS

Q22. HOW ARE ENERGY AND DEMAND BY JURISDICTION DETERMINED?

A. Energy for each jurisdiction is based on billed energy, adjusted for losses. For jurisdictional demand at the time of the native system peak, New Mexico load data are gathered from substations in New Mexico and along the Texas-New Mexico state line. The New Mexico load contribution for each substation is updated on an annual basis. The total coincident demand from New Mexico and EPE's wholesale customer, Rio Grande Electric Cooperative ("RGEC"), is subtracted from total system demand at time of peak to determine Texas coincident load. Maximum and coincident demand by rate class are determined by using billed energy and the estimated load and coincidence factors from the load studies. Energy and demand losses are applied in this model using the most current loss study.

Q23. DO THE ENERGY AND DEMAND ALLOCATORS NEED TO TAKE LOSSES INTO ACCOUNT?

A. Yes. Customers are served at different voltage levels and, therefore, have different losses associated with service. For proper allocation of costs, both energy and demand allocators take losses into account to appropriately reflect generation "at the source". EPE's latest loss study is used in the development of EPE's allocators and is further discussed in Section V of this testimony.

Q24. WHAT ADJUSTMENTS WERE MADE TO THE JURISDICTIONAL ENERGY AND DEMAND ALLOCATORS?

A. Generation from EPE's resources that are assigned to serve customers from a specific jurisdiction were directly assigned to the relevant jurisdiction and removed from the retail customers' energy and demand usage used in the jurisdictional allocators. For example, Newman Unit 6 is assigned to Texas, and the Carne Project is assigned to New Mexico. Please refer to the direct testimony of EPE witness Jeffery Hughes for EPE's generation resources and refer to the direct testimony of EPE witness Victor Martinez for a discussion of EPE's battery energy storage system resources.

Q25. WHY IS THE ADJUSTMENT FOR DEDICATED RESOURCES TO THE JURISDICTIONAL ENERGY AND DEMAND ALLOCATORS IN THE TOTAL COMPANY COST OF SERVICE STUDY APPROPRIATE?

A. The adjustment is appropriate because the costs associated with these generation resources are recovered from customers in specific jurisdictions and are directly assigned to the relevant jurisdiction in the jurisdictional costs of service study.

Q26. WAS A SIMILAR ADJUSTMENT MADE FOR ANY EPE OWNED DEDICATED GENERATION IN CASE NO. 20-00104-UT?

A. Yes. This adjustment was made to Holloman Air Force Base's ("HAFB") energy and demand usages to account for the solar photovoltaic facility that was built to serve HAFB's specific load. This adjustment was made in the same manner as solar resources that were built to serve a specific jurisdiction.

Q27. HAS EPE MADE ANY NOTEWORTHY CHANGES IN ITS ALLOCATION METHODOLOGY FROM ITS LAST NEW MEXICO BASE RATE CASE FILING IN CASE NO. 20-00104-UT?

A. Yes. EPE changed the billing determinants used in calculating the production and transmission allocation factors for distributed generation ("DG") customers.

Q28. CAN YOU DESCRIBES EPE'S HISTORICAL TREATMENT OF DG CUSTOMERS' BILLING DETERMINANTS IN THE CALCULATION OF

THE ALLOCATION FACTORS AND HOW THIS DIFFERS FROM THE CURRENT CALCULATION?

A. Yes, historically, EPE has made an adjustment ("DG Adjustment") to the per book billing determinants to account for the total energy delivered to DG customers rather than using net energy. Total energy delivered reflects the energy delivered by EPE to DG customers, while net energy is the difference between the energy delivered and the energy received by EPE from the DG customers. Historically, these adjusted billing determinants have been used in the calculation of the production, transmission, and distribution allocation factors.

For the current rate case, EPE did not include the DG Adjustment in its calculation of the production and transmission allocations factors but did include it in its calculation of the distribution allocators. Contrary to the historical treatment of DG customers' billing determinants, the current production and transmission allocators rely on DG customers' net energy as opposed to delivered energy.

Q29. WHY IS EPE USING NET ENERGY FOR DG CUSTOMERS IN THE CALCULATION OF THE PRODUCTION AND TRANSMISSION ALLOCATORS?

A. EPE is using net energy for DG customers because these customers produce a portion of the energy they consume, reducing the generation required to serve these

customers throughout the year and at the time of EPE's system peak. EPE's use of DG customers' net energy in the production and transmission allocation factors recognizes the customers' reduced energy consumption and contribution to the native system peak resulting from producing a portion of their own generation.

Q30. WHY IS THE ADJUSTMENT TO ACCOUNT FOR ENERGY DELIVERED TO DG CUSTOMERS APPROPRIATE IN THE CALCULATION OF THE DISTRIBUTION ALLOCATORS?

A. The adjustment is appropriate because distribution costs are a function of all energy delivered to each customer's service point regardless of the type of customer.

Q31. WHAT IS THE EFFECT TO THE JURISDICTIONAL AND CLASS ALLOCATORS OF USING NET ENERGY FOR DG CUSTOMERS IN THE PRODUCTION AND TRANSMISSION ALLOCATORS?

A. Using net energy instead of delivered energy for DG customers resulted in a change to both jurisdictional and class allocators. At the jurisdictional level, New Mexico saw a decrease in the E1Energy allocator, as well as decreases in all the demand jurisdictional allocators for both per book and adjusted allocation factors. At the class level, the use of net energy resulted in a decrease to the residential class energy and demand allocators. Changes to all allocators are shown in Exhibit ES-2.

Q32. DID EPE DEVELOP ANY SCENARIOS FOR THE ALLOCATION FACTORS?

A. Yes, EPE produced two scenarios for the allocation factors. Scenario 1 was developed to illustrate the effect of reopening Rate No. 07-City and County Service to new customers. EPE developed this illustrative set of class allocation factors to comply with the Commission Case No. 20-00104-UT Final Order, but it does not reflect EPE's proposal for this current base rate case. This alternative set of class allocation factors is displayed in Exhibit ES-3. EPE witness Mr. Hernandez uses these illustrative allocators in a cost of service study to comply with that final order regarding reopening Rate No. 07 to new customers.

In addition, EPE also developed a second scenario of allocation factors to support the large load tariffs presented by EPE witness Mr. Carrasco. These allocators are also found in Exhibit ES-3.

C. LOAD DATA AND LOAD PROFILE FOR ELECTRIC VEHICLE ("EV") CHARGING RATE

Q33. WHAT INFORMATION DID EPE AGREE TO PROVIDE FOR RATE NO. 42 – EXPERIMENTAL ELECTRIC VEHICLE CHARGING RATE ("RATE NO. 42") IN THE LAST RATE CASE?

A. EPE agreed to provide the following information:

- The maximum number of customers taking service under the rate schedule by rate class.
- The number of customers that have taken service under the rate schedule at any one time since implementation.
- The average bill for Rate No. 42 customers.
- The load data and the load profile of Rate No. 42 customers, including data on how EV charging load coincides with EPE's system peak.

The following two questions in my testimony address the load data and load profile requirement as well as the charging behavior at the time of EPE's system peak. All other requirements are addressed by EPE witness Rene Gonzalez.

Q34. DID EPE ANALYZE THE LOAD PROFILE OF CUSTOMERS ENROLLED IN RATE NO. 42?

A. Yes. EPE's Load Research & Data Analytics Department produces typical day profiles per month for customers enrolled in Rate No. 42 to better understand the energy consumption of these customers in addition to measuring the effectiveness of the rate to incentivize off-peak EV charging. The load study and load profiles for Rate No. 42 are provided in Workpaper ES-1. Figures ES-1 to ES-3 provide the average hourly profile for customers during the Summer (June-September),

Non-Summer Daylight Saving Time (March, April, May and October), and Non-Summer Standard Time (January, February, November, and December) months. Figures ES-1 to ES-3 show that the majority of customer EV charging occurs during the super off-peak and off-peak periods, effectively reducing demand during on-peak hours. All months show a distinct reduction in demand during the on-peak afternoon period, with the lowest demand occurring between approximately 2–4 PM, after which the demand starts to increase across all months. The pronounced reduction in on-peak demand, followed by a post-peak rebound, strongly suggests intentional load shifting away from on-peak hours.

Figure ES-1 – Average Daily Charging Profiles Summer (June-September) Months of the Base Period

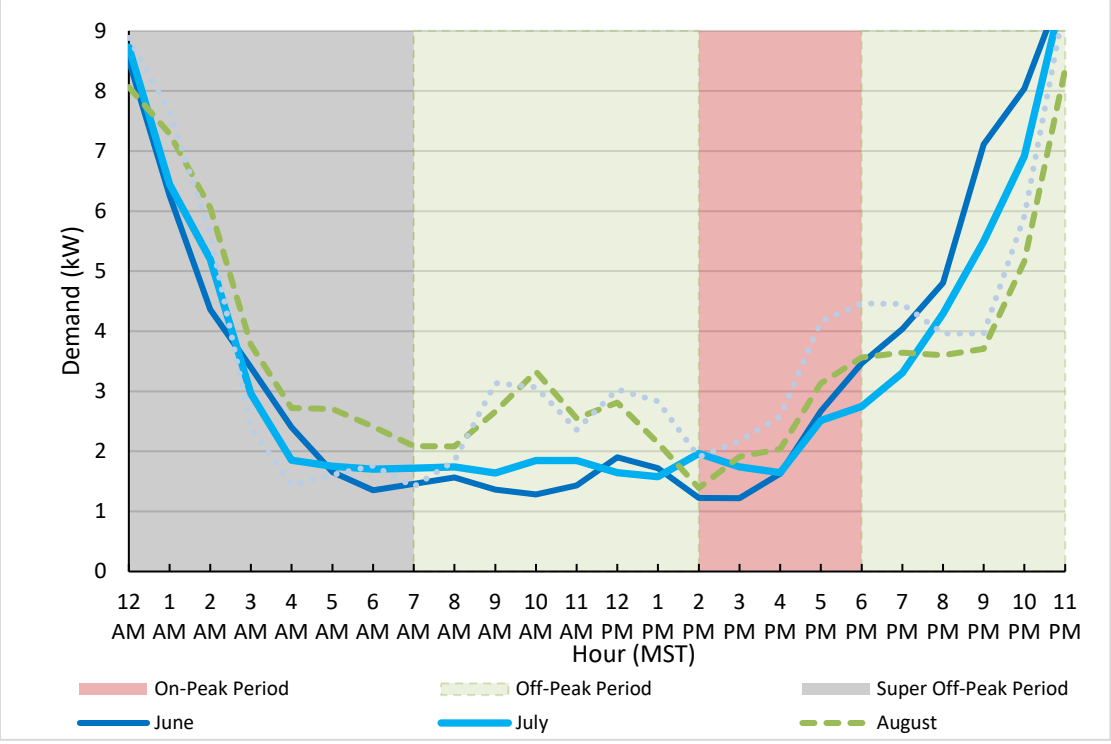

Figure ES-2 - Average Daily Charging Profiles Non-Summer Daylight Saving Time (March, April, May and October) Months of the Base Period

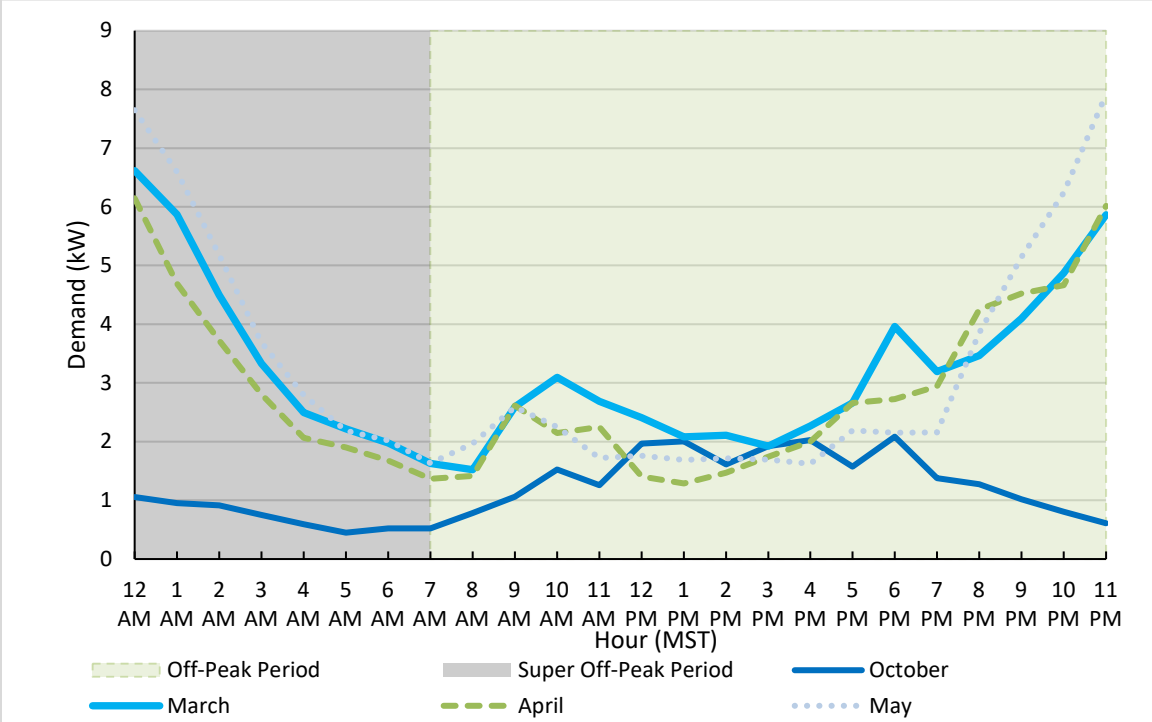

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Figure ES-3 - Average Daily Charging Profiles Non-Summer Standard Time (January, February, November, and December) Months of the Base Period

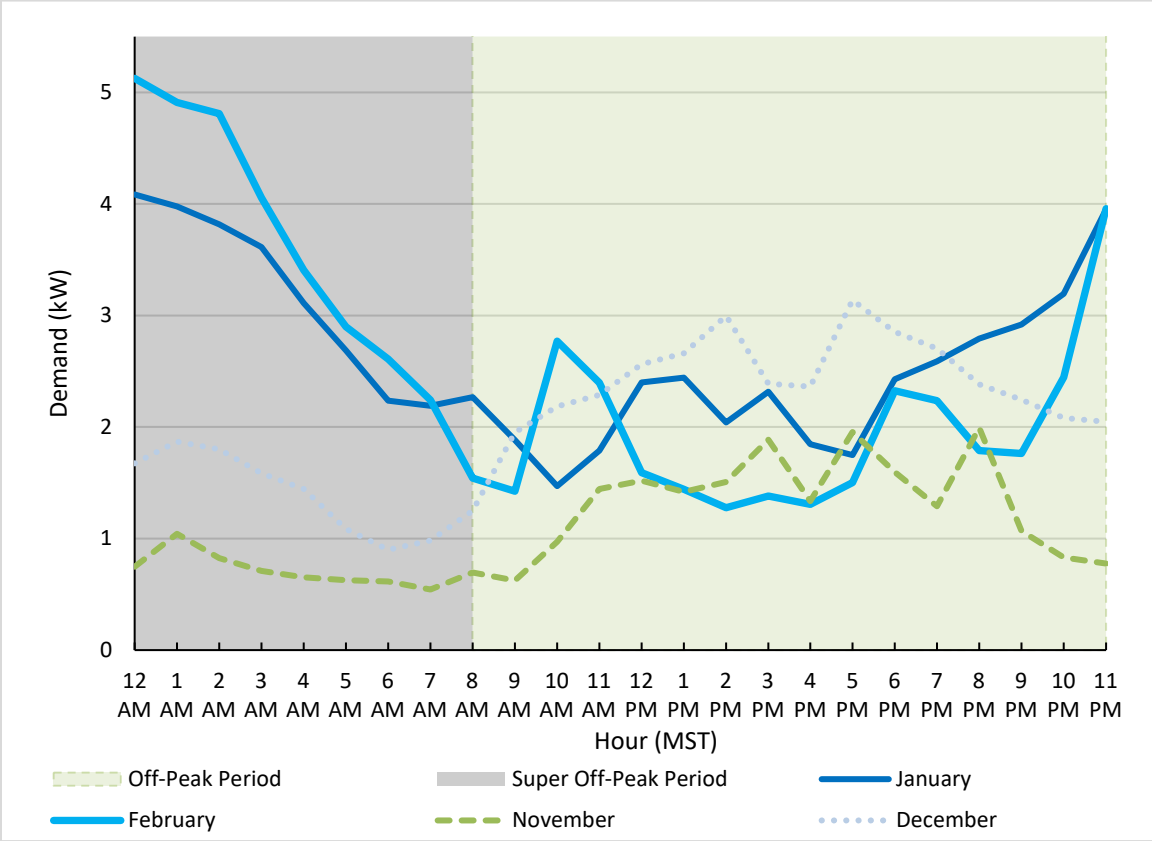

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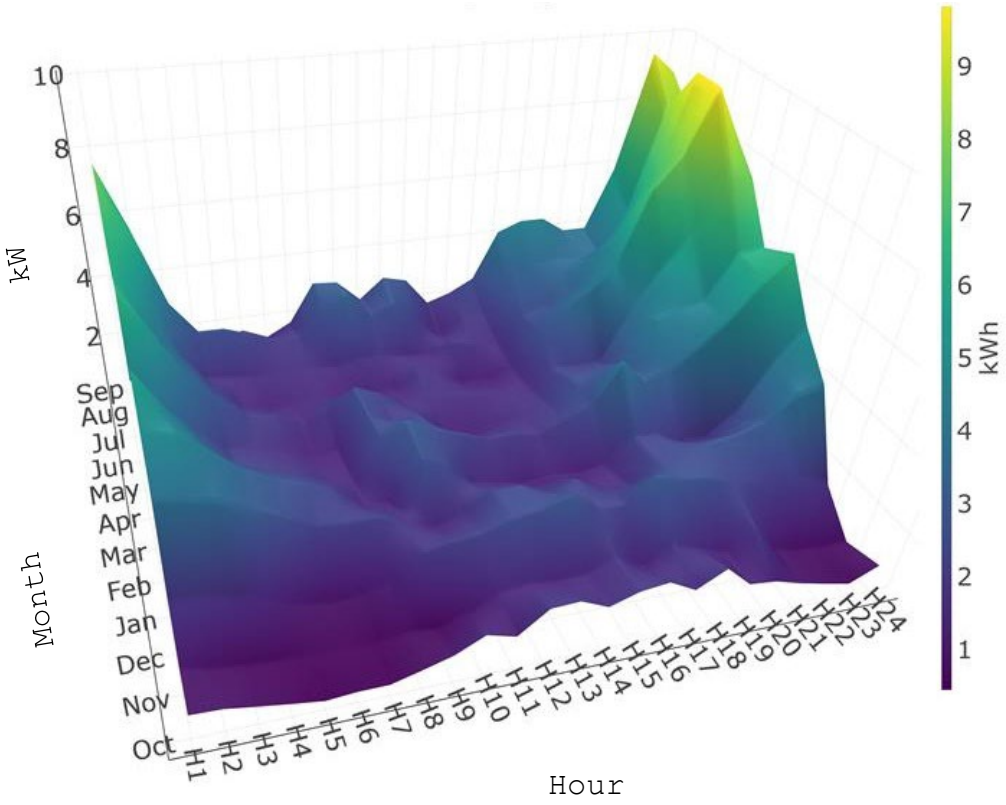
Figure ES-4 provides an annual look at the hourly profile for Rate No. 42 customers.

Figure ES-4 - Average Daily Charging Profiles for Base Period



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Q35. DID EPE ANALYZE THE IMPACT OF EV CHARGING FROM CUSTOMERS ENROLLED IN RATE NO. 42 ON EPE'S NATIVE SYSTEM PEAK?

A. Yes. EPE's Load Research & Data Analytics Department produces load studies to analyze demand and energy consumption during system peak hours of customers enrolled in Rate No. 42. Figure ES-5 summarizes the average monthly energy per customer and the percentage of energy used during the on-peak, off-peak and super off-peak periods during the 4-CP summer months (June-September). Figure ES-6 shows the coincidence factor (percentage of the maximum demand with respect to the demand at the time of the system peak) per customer during the 4-CP summer months (June-September). Workpaper ES-1 provides the load study information for the Base Period October 2024 – September 2025.

The graphs indicate that customers enrolled in Rate No. 42 predominantly charge during off-peak and super off-peak periods across the summer months (June through September), with on-peak energy consumption comprising a relatively small portion of total usage. On-peak energy use remains limited to approximately 6.4–10.5% of total consumption during June through September. Off-peak periods consistently account for the largest share of energy consumption, ranging from

approximately 52% to 58% of total energy use, while super off-peak periods contribute an additional 34% to 40%. This distribution indicates sustained customer behavior aligned with time-of-day price signals.

The observed pattern reflects effective load-shifting behavior and demonstrates the continued ability of participating customers to manage usage in a manner that mitigates on-peak demand impacts. This load distribution is consistent with program objectives to reduce on-peak system impacts.

Figure ES-5 - Monthly Energy and the Percentage of Energy used During the On-Peak, Off-Peak and Super Off-Peak periods during the summer months (June-September) of the Base Period.

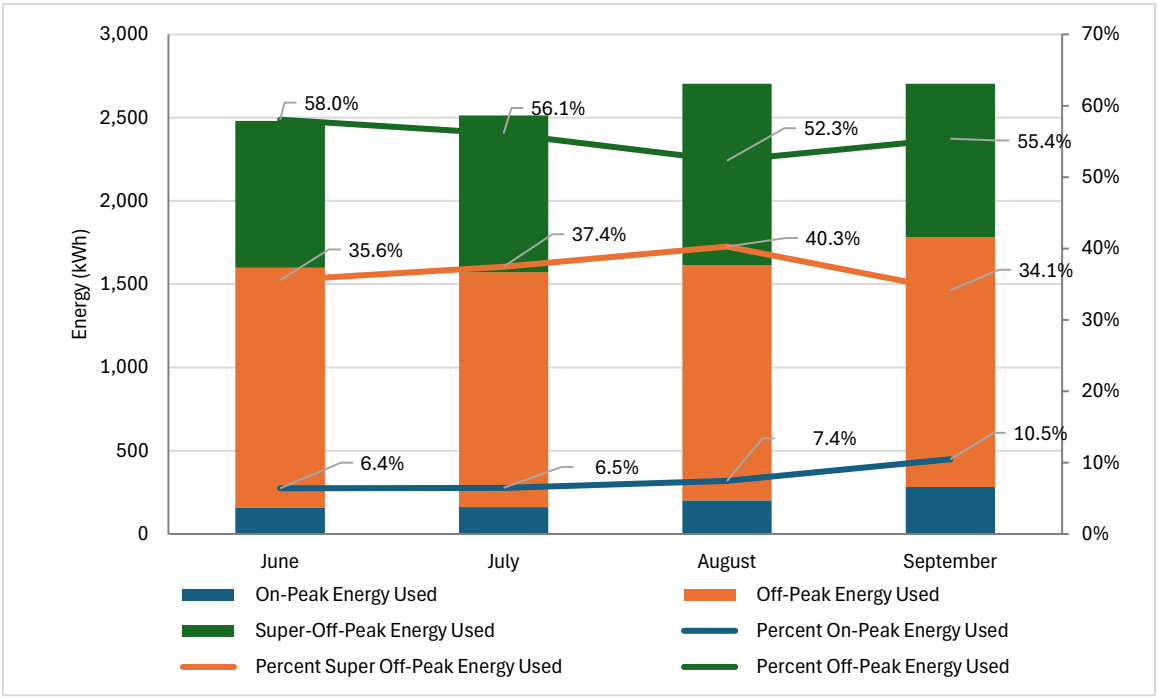
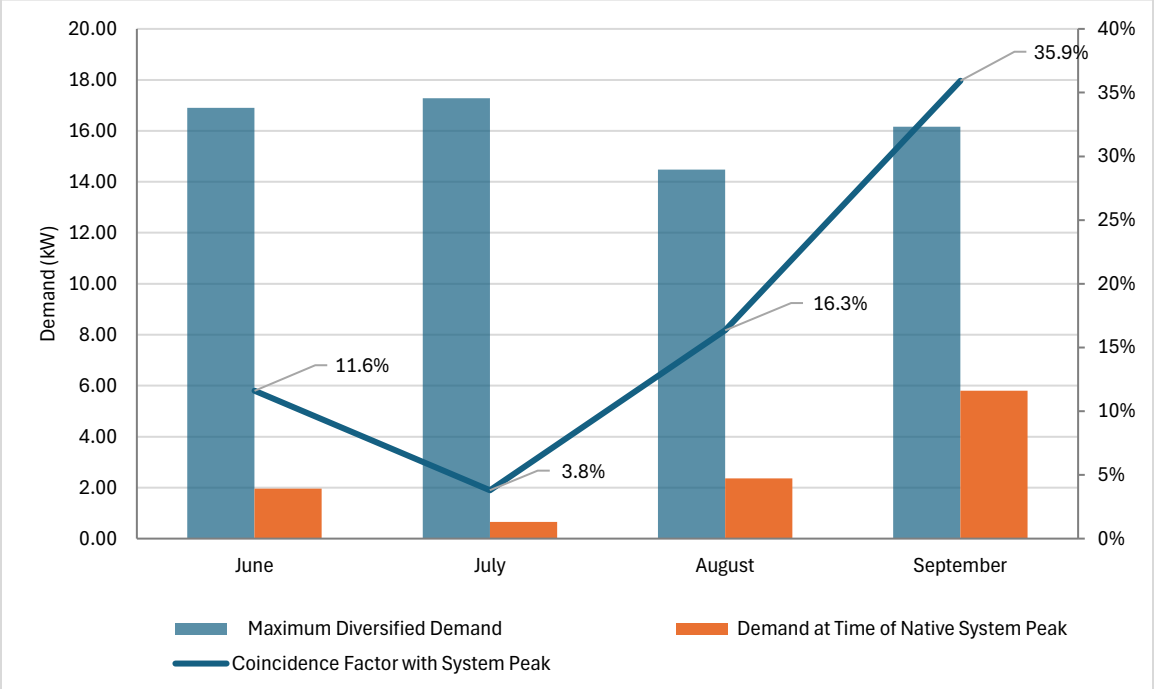


Figure ES-6 - Maximum Demand and Coincidence Factors Per Customer During the 4-CP Summer Months (June-September) of the Base Period.



D. PEAK DEMAND

Q36. WHAT IS THE TREND OF THE TOTAL SYSTEM PEAK DEMAND?

A. EPE is a summer peaking utility. This means that EPE's system will experience a significantly higher load during the day between the months of June to September than it experiences at other times of the year. To efficiently meet peak demand,

EPE's generation must be readily available during peak summer conditions and be able to cycle or shut down completely during off-peak periods (e.g., nights, weekends and winter) and ramp up without limit as soon as needed. Over the past ten years (2015-2025), the system peak demand has had a compound annual growth rate ("CAGR") of 2.6%, while native energy has had a CAGR of 0.8%. This has resulted in a decreasing trend in EPE's system load factor.

Over the past decade, the EPE system load factor has decreased. Overall, the system load factor dropped from 53.2% in 2014 to 45.1% in 2025. The EPE system load factor has been declining over time in response to several factors: a rise in refrigerated air conditioning systems, an increase in energy efficiency, warming climate trends, an increase in the number of DG customers, and a decrease in industrial customers relative to residential customers.

Refrigerated air conditioning units use significantly more electricity than evaporative cooling units. The demand for electricity from refrigerated air conditioning units tends to be highest during hot summer days, when they cycle on and off in response to hot temperatures. In contrast, evaporative air conditioners have limited cycling. Increasing adoption of refrigerated air contributes to a downward trend in the system load factor, which means that demand grows faster than energy. Over time, this results in swings in demand that become more pronounced during the summer months, thus requiring additional generation to

meet this demand. On the other hand, increases in energy efficiency have led to a decrease in energy consumption. The effect of energy efficiency is more noticeable during the winter months as consumers continue to switch to LED lighting and ENERGY STAR appliances. In addition to the above, continued warming trends have resulted in above average temperatures in the summers months, driving growth in the native system peak.

Furthermore, the increased growth in customer-owned solar DG and decreased consumption by industrial customers relative to residential customers has also reduced the overall system load factor. DG customers on average have lower load factors than their non-solar counterparts, while industrial customers tend to be high load factor customers. This has resulted in a shift in the composition of EPE's customer mix to lower load factor customers.

Despite these factors exerting downward pressure on EPE's system load factor, EPE expects a reversal of this trend in the future. The emergence of EVs, along with proposed managed EV charging programs, can help alleviate this pressure by shifting usage to non-peak hours. In addition, expanded use of time-varying rate designs, such as time-of-day rates, will provide a financial incentive in customer bills to shift usage to off-peak or super off-peak hours. Finally, EPE has received inquiries from data centers interested in expanding into our service area.

These data centers are high load factor customers that can contribute positively to our overall load factor.

IV. WEATHER NORMALIZATION

Q37. DID EPE UTILIZE A WEATHER ADJUSTMENT IN THE ANNUALIZATION PROCESS?

A. Yes. The weather normalization adjustment results in a level of sales that can be expected during the Base Period with average weather. The total weather normalization adjustment for New Mexico retail customers is an increase of 13,904,901 kilowatt hours ("kWh") (0.76%) from total New Mexico retail sales of 1,827,634,509 kWh at the end of the Base Period ending September 30, 2025. Similarly, a total weather normalization adjustment was made for Texas.

Q38. WHY IS IT REASONABLE AND NECESSARY TO UTILIZE A WEATHER NORMALIZATION ADJUSTMENT IN THE ANNUALIZATION PROCESS?

A. Weather normalization adjustments are necessary to avoid over- or understating the level of sales that could be expected during a year with average weather. Weather can have a profound impact on the month-to-month fluctuations in EPE's system

energy sales. This is due in large part to the operation of heating and cooling equipment that is weather sensitive.

In EPE's service area, the adoption of central refrigerated air conditioning is increasing. Central refrigerated air conditioning equipment is replacing evaporative cooling equipment in residences and commercial establishments. Additionally, new residential construction projects usually include the use of refrigerated air units. As a result, EPE's load has become more weather sensitive because central refrigerated air conditioning uses much more energy and demand than evaporative cooling equipment.

Q39. IS THE COMPANY'S PROPOSED WEATHER NORMALIZATION ADJUSTMENT CONSISTENT WITH THE WEATHER NORMALIZATION ADJUSTMENT APPROVED BY THE COMMISSION IN EPE'S MOST RECENT RATE CASE?

A. Yes. The proposed weather normalization adjustment methodology is consistent with the methodology of the weather normalization adjustment approved by the Commission in EPE's most recent general rate case, Case No. 20-00104-UT.

Q40. DOES EPE USE WEATHER STATIONS FOR BOTH EL PASO AND LAS CRUCES?

A. Yes. An analysis of historical heating degree days ("HDD") and historical cooling degree days ("CDD") for El Paso and Las Cruces revealed that there are climate differences between the two locations. I note this in Exhibit ES-4. These degree days measure the fluctuations in daily average temperature below or above the designated base temperature of 65 degrees Fahrenheit. Temperatures below the designated base temperature lead to increased use of heating appliances and are, therefore, referred to as HDDs. Conversely, fluctuations in daily average temperature above the designated base temperature lead to greater use of air conditioning and are referred to as CDDs.

Despite the fact that El Paso and Las Cruces are located in a dry desert climate and are less than 50 miles apart, they have some climate differences that make it important to match weather data at both locations to adjust their respective energy sales. Even though the temperatures in both cities tend to move in the same direction relative to each other, El Paso tends to be warmer than Las Cruces. Over the last 10 years, Las Cruces has consistently had fewer annual CDDs than El Paso.

Given these consistent differences in weather patterns between the two cities, EPE has concluded that it is appropriate to use two different weather sites for our analysis.

Q41. WHY HAS EPE MADE WEATHER NORMALIZATION ADJUSTMENTS TO THE ENERGY OF THE VARIOUS RATE CLASSES?

A. Adjustments for fluctuating temperature conditions are made to ensure that the kilowatt-hour sales levels, upon which rates are based, neither over-recover nor under-recover the Company's allowed cost of service. Base Period kilowatt-hour sales were adjusted to normalize Base Period sales for those rate classes whose use of electricity is sensitive to temperature conditions. During a given period, such as the Base Period, temperature conditions may be warmer or colder than normal. As a result, sales of electricity may be higher or lower than the level that will normally occur.

Q42. HOW WERE EPE'S WEATHER NORMALIZATION ADJUSTMENTS MADE?

A. EPE prepared statistical models that measure customer responsiveness to temperatures for all rate classes. Only those econometric models that displayed statistically significant effects to fluctuations in temperature were included in EPE's weather adjustment. EPE identified seven such econometric models in New Mexico.

The seven individual Rate Class models are:

- Rate 01 - Residential Service;

- Rate 03 - Small General Service;
- Rate 04 - General Service;
- Rate 05 - Irrigation Service;
- Rate 07 - City and County Service;
- Rate 08 - Water, Sewage, Storm Sewage Pumping or Sewage Disposal;
- Rate 10 - Military Research and Development Power Rate; and
- Rate 26 - State University Service.

Q43. WHICH RATE CLASSES WERE EXCLUDED FROM WEATHER NORMALIZATION ADJUSTMENTS?

A. Weather normalization adjustments were not made to Lighting classes or to Large Commercial and Industrial customer classes, since these customers' uses of electricity are not sensitive to fluctuations in temperature. Further, no weather normalization adjustment is proposed for RGEC since EPE does not have access to end-user information for this wholesale customer.

Q44. PLEASE SUMMARIZE THE PROCESS FOR CALCULATING WEATHER NORMALIZATION ADJUSTMENTS.

A. Weather normalization adjustments were calculated in a three-step process. First, linear regressions were employed to quantify the influence that factors such as

CDDs, HDDs, and economic and/or demographic variables have upon monthly electric consumption. A number of linear regression models were examined, and the models were tested for statistical strength and reasonableness.

Second, the coefficients of the regression equations were translated into monthly kWh adjustments for the Rate Classes. The regression coefficients for the explanatory variables in each regression equation equal the change in the dependent variable (kWh usage) associated with a one unit change in the explanatory variable. Thus, the regression coefficients for CDD provide the changes in monthly usage per customer associated with a one-unit change in CDDs. Similarly, the regression coefficients for HDD provide the changes in monthly usage per customer associated with a one-unit change in HDDs. Multiplying the degree day regression coefficient by the difference between the normal number of degree days and the Base Period actual degree days in a month produces the amount by which Base Period kWh varied from kWh use under normal temperature conditions. Exhibit ES-5 shows these calculations.

In the third step, for the residential class, the kWh per customer impact is multiplied by the number of monthly customers. The residential rate class is estimated on a use per customer basis because residential customers display homogenous consumption. The kWh weather impact estimate for this class is based on a per customer basis so multiplying by the number of customers in that month

is necessary to get a total weather effect value. Allocation of the monthly weather normalization adjustments is provided in Exhibit ES-5.

Q45. HOW DOES EPE CALCULATE NORMAL WEATHER?

A. EPE uses a 10-year average of monthly National Oceanic and Atmospheric Administration ("NOAA") HDDs and CDDs, adjusted for billing cycles, as a proxy for future average weather conditions. This weather data comes from official NOAA weather stations and is adjusted for missing values and other anomalies through AccuWeather.

NOAA is a federal agency that monitors climate and collects and publishes local weather pattern data. NOAA calculates HDD and CDD data that are used by forecasters to estimate the impact of weather on energy sales and load. Because CDDs and HDDs are recorded on a calendar month basis, while booked month sales are recorded over 18 billing cycles that normally include portions of two calendar months, it was necessary to transform these calendar month variables into variables that correspond to EPE's billing cycles. This transformation was accomplished through the use of two-month moving average CDD and HDD variables.

Q46. OTHER THAN CDDS AND HDDS, WHAT OTHER VARIABLES WERE EMPLOYED IN MODELING CONSUMER USE OF ELECTRICITY?

A. In addition to including CDD and HDD variables, each weather model was structured to incorporate economic and/or demographic variables that are likely to affect the use of electricity by the class being modeled.

Q47. WERE THE MODELS TESTED FOR STATISTICAL ACCURACY?

A. Yes. All models met statistical requirements for logical consistency in terms of the explanatory variables employed, signs of the coefficients, and consistency of results using alternative model specifications. In addition, the models were tested for significance of the independent variables as well as goodness of fit. The statistics of the models indicate that we have confidence in the degree day and economic variables employed in the models, and that these variables do an excellent job of explaining changes in energy use.

Q48. CAN YOU DESCRIBE HOW THE RESULTS OF THE REGRESSION EQUATIONS WERE TRANSLATED INTO WEATHER NORMALIZATION ADJUSTMENTS FOR EACH AFFECTED CLASS?

A. Yes. As described previously in my testimony, the coefficients of the CDD and HDD variables represent the change in energy use that corresponds to a one-degree day change in temperature. The weather effect is estimated as the product of the CDD and HDD coefficients and the difference between actual Base Year degree

days and normal degree days. For example, for the New Mexico Residential model, the July 2025 weather normalization adjustment was calculated as follows:

Normal CDD		539 CDD
Actual CDD	-	475 CDD
Difference CDD		64 CDD
August CDD Coefficient	X	0.9719 kWh/CDD/Customer
Difference X Coefficient		62 kWh/Customer
Number of Customers	X	97,069 Customers
Adjustment		6,063,866 kWh

Note: Due to rounding, the totals in the example above do not add to the total adjustment.

All other months were calculated in the same manner using data specific to each month. The example above employs a monthly use per customer as the dependent variable. The models that employ total rate class kWh as the dependent variable do not have to multiply the resulting change in kWh by the number of customers in the class. Once the monthly kWh use for the weather sensitive classes was developed, the weather-adjusted monthly kWh use was further adjusted for year-end customer growth as explained in the direct testimony of EPE witness Mr. Gonzalez. Please refer to Exhibit ES-5 for the monthly calculations by rate class described previously.

Q49. WHAT WAS THE EFFECT OF THE WEATHER NORMALIZATION ADJUSTMENT ON KWH SALES FOR NEW MEXICO RETAIL CUSTOMERS?

A. The weather normalization adjustment reflects a reduction in kWh sales to account for the slightly warmer weather during the Base Period. The reduction is necessary to re-state sales at more normal levels that can be reasonably anticipated when new rates are placed into effect. The total weather adjustment for New Mexico retail customers is an increase of 13,904,901 kWh (0.76%) from total New Mexico retail Base Period sales of 1,827,634,509 kWh.

This adjustment is provided for each affected rate class by month on Exhibit ES-5. In addition, Exhibit ES-5 also provides the calculation of the monthly weather normalization adjustments for each rate class.

V. UPDATED SYSTEM LOSS ANALYSIS

Q50. PLEASE DESCRIBE THE SYSTEM LOSS ANALYSIS EPE PROPOSES BE ADOPTED IN THIS PROCEEDING.

A. EPE commissioned Management Applications Consulting, Inc. ("MAC") in May 2022 to provide an updated system-wide loss study based on calendar year 2021 data (the "2021 loss study" or "2021 system loss study"). MAC performed the 2017 loss study, which was accepted by the Commission and is currently utilized by EPE for allocation,

rate design and fuel adjustment purposes in New Mexico. The 2021 loss study uses the same methodology used by MAC in the 2017 loss study.

The system loss study develops separate demand (kW) and energy (kWh) loss factors for each voltage level of service in EPE's power system. The cumulative loss factor results by voltage level are used to adjust metered kW and kWh sales data for losses in performing cost of service analysis, rate design, developing the proposed Fuel and Purchased Power Cost Adjustment Clause factor, and for other analyses which require loss adjustments.

The loss analysis model incorporates extensive use of the Company's peak hour power flow data. In addition, load data at the substation and customer level, coupled with primary and secondary network information were used to model the distribution system to calculate losses. Measured and estimated load data provides a means of calculating reasonable estimates of losses by using a "top down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage transmission system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and energy delivered to the loads.

EPE's load research data provided the starting point for performing the "bottom-up" approach for estimating the remaining distribution losses. Basically, this approach develops line loadings by first determining loads and losses at each level

beginning at a customer's meter and service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substations. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the factors.

Q51. IS THE UPDATED SYSTEM LOSS STUDY PROVIDED WITH EPE'S APPLICATION IN THIS PROCEEDING?

A. Yes, the 2021 system loss study is included as Schedule M-3.

Q52. HAVE THE UPDATED LOSS FACTORS AND THE RESULTS OF THE LOSS STUDY BEEN INCORPORATED INTO EPE'S PROPOSED RATES?

A. Yes. In addition to the inclusion of the demand and energy loss factors in the calculation of demand and energy allocation factors, the calculated average loss factors for line transformers were used in the calculation of the proposed Meter Voltage Adjustment included in the Municipal Pumping, General Service, Large Power Service, University Service, and Interruptible Service rates.

Q53. HOW DO THE PROPOSED DEMAND AND ENERGY LOSS FACTORS COMPARE TO THOSE CURRENTLY EMPLOYED BY EPE?

A. The summary table provided in Schedule M-3 compares the proposed demand and energy loss factors at various voltages.

VI. ENERGY AND DEMAND FORECAST

Q54. PLEASE DESCRIBE THE APPROACH THAT EPE USED TO DEVELOP ITS SALES FORECASTS PRESENTED IN SCHEDULE P-1 IN THE RATE APPLICATION.

A. EPE employs an econometric approach. This approach involves the application of mathematics and statistical methods to the analysis of economic data and the relationship between economic variables to provide an empirical estimation of those relationships. EPE's econometric forecasting models relate customer electric usage to service area trends in population, local economic indicators, and weather to estimate future electricity sales. For example, population, personal income, and weather are typical drivers of electricity sales: more customers and increased income to purchase appliances will typically result in higher electricity demand. The primary reference for these assumptions is the regional macroeconomic forecasts prepared by S&P Global.

Q55. IS AN ECONOMETRIC FORECASTING METHODOLOGY GENERALLY USED BY COMPANIES IN THE ELECTRIC INDUSTRY?

A. Yes.

Q56. PLEASE DESCRIBE THE METHODOLOGY EPE USED TO DEVELOP THE SALES AND DEMAND FORECASTS PRESENTED IN THIS TESTIMONY.

A. EPE develops jurisdictional customer class sales forecasts based on monthly macroeconomic data and historic and forecasted customer data for each respective jurisdiction. EPE develops individual rate class econometric forecasts if rate classes are experiencing changes not in line with their historical trend. EPE's forecasts for energy sales are functions of variables such as population, income, employment, and other economic and demographic variables. The econometric sales forecasts and resulting peak demand forecast were adjusted to reflect energy efficiency, distributed generation, and an increase in sales from electric vehicle adoption and expected new load from new and current customers.

Q57. ARE ALL OF EPE'S SALES ESTIMATES BASED ON AN ECONOMETRIC MODEL?

A. No. In the few cases where adequate data was not available to support statistical analysis, EPE relied on non-econometric sales and load information. Examples of situations that require non-econometric estimates include significant

expansion/reduction by an existing customer as well as expansion of DG customers and transportation electrification.

Given that DG is relatively new for modeling purposes, there is limited historical regional data, so it is not suitable for econometric forecasting models. Future estimates for DG customers and load are based on recent trends, sample studies, and known or reasonably predictable changes in consumption levels.

Finally, similar to DG, EPE also forecasts the expected adoption of EVs. The energy and demand forecast include out-of-model adjustments for light-duty, medium-duty, heavy-duty EVs and electric buses.

Q58. HOW DOES EPE DETERMINE THE MONTHLY SYSTEM ENERGY REQUIREMENT (SALES AT THE SOURCE)?

A. EPE combines the annual retail sales, sales to RGEC, and Company use, and then calculates line losses using a loss rate derived from the 2021 system loss study. These system losses must be included with sales at the meter to accurately develop the total energy requirement needed to deliver electricity to EPE's customers. Finally, out-of-model adjustments are made to account for energy efficiency, DG customers, EVs, and data center consumption anticipated for the forecasting period.

Q59. HOW ARE EPE'S PEAK DEMAND FORECASTS DEVELOPED?

A. EPE uses the native system load factor relationship to estimate future annual peak demands. Load factor defines the relationship between energy and peak demand.

System Load Factor = System Energy / (Peak Demand x Hours in a Year)

For example, the annual load factor for 2024 was:

System Load Factor = 9,261,368 MWh / (2,316 MW x 8,784 hours) = 0.455

EPE applied a one-year load factor of 0.455. This load factor was used to develop the peak demand forecast for 2025. The load factor was then decreased at an equal rate for 5 years until reaching the load factor of 0.438 witnessed in 2023, which is the lowest load factor observed by EPE. The load factor was kept constant for the remainder of the forecasting period. Similar to the native energy forecast, these values are then adjusted for expected decreases/increases to load resulting from energy efficiency, DG, and EVs. The final adjustment made to forecasted peak demand is to subtract interruptible load.

Q60. WHAT ARE THE ECONOMIC AND DEMOGRAPHIC VARIABLES USED IN DEVELOPING EPE'S FORECASTS?

A. The economic and demographic variables used in the forecasts are the projections for gross metropolitan product, wages, employment, personal income, population, and weather.

Q61. DOES EPE RELY ON AN INDEPENDENT SOURCE IN ACCOUNTING FOR THE MODEL'S USE OF ECONOMIC AND DEMOGRAPHIC FORECASTS?

A. Yes. The population, income, and employment data series for EPE's service area are taken from S&P's regional economic forecasts for El Paso and Las Cruces that I described earlier in my testimony. S&P's forecasts provide EPE with data that is independent and free from any internal bias. S&P provides EPE with a large data set of regional variables that are routinely updated. Moreover, S&P is an internationally recognized macroeconomic forecasting service with a customer base that includes clients in industry, banking, government, and academic institutions.

VII. SUMMARY AND CONCLUSIONS

Q62. PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS.

A. My testimony discusses EPE's load research function and its role in gathering the energy and demand data necessary for assigning costs to jurisdictions and rate classes, as well as for the development of tariffs. The load research methodologies used by EPE are fair and reasonable for the assignment of costs and the development of tariffs and are consistent with prior filings.

I describe and support the proposed weather normalization adjustment. In my opinion, the proposed weather normalization adjustment is both fair and reasonable. The economic models used to develop the adjustments employ standard industry practices, and the models have a high level of statistical confidence. The proposed weather normalization adjustment follows a consistent methodology with the weather adjustment submitted in EPE's previous rate case. Furthermore, the weather normalization adjustment fairly and reasonably reflects normal weather during the Base Period. The total weather normalization adjustment for New Mexico retail customers is an increase of 13,904,901 kWh (0.76%) from total New Mexico retail Base Period sales of 1,827,634,509 kWh.

I describe and support EPE's 2021 system-wide loss study, which is based on the methodology used in EPE's most recently approved 2017 system-wide loss study, results in reasonable system loss factors, and should be approved by the Commission.

Finally, I describe EPE's forecasted sales and demand in support of Schedule P-1. In my opinion, the forecasted sales and demand values are both fair and reasonable. These growth rates are consistent with recent customer growth trends and the economic growth projections for our service territory.

Q63. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

RATE	MONTH	NUMBER OF CUSTOMERS		AVG ENERGY KWH		AVG MAX CLASS DEMAND KW		AVG COINCIDENT DEMAND KW		AVG NON-COINCIDENT PEAK KW		LOAD FACTOR		COINCIDENCE FACTOR	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-01	Oct-24	64,051	127	649	670	2.00	2.03	1.82	1.85	4.49	4.64	43.6%	44.4%	91.1%	91.4%
N-01	Nov-24	67,124	127	538	559	1.06	1.19	0.86	0.83	4.05	4.17	70.2%	65.2%	80.6%	70.0%
N-01	Dec-24	69,775	127	655	652	1.30	1.34	1.28	1.30	4.27	4.40	67.8%	65.6%	98.3%	97.5%
N-01	Jan-25	72,219	127	784	743	1.57	1.57	1.55	1.55	4.55	4.36	67.0%	63.6%	98.3%	98.8%
N-01	Feb-25	74,575	126	513	508	1.20	1.24	1.01	1.10	4.08	4.10	63.4%	61.0%	84.2%	89.0%
N-01	Mar-25	75,781	127	548	554	1.09	1.20	1.03	1.11	4.20	4.29	67.6%	62.0%	94.5%	92.3%
N-01	Apr-25	76,636	127	555	581	1.55	1.85	1.55	1.53	4.43	4.56	49.8%	43.6%	100.0%	83.0%
N-01	May-25	77,573	124	715	759	2.24	2.37	2.24	2.33	4.72	4.76	43.0%	43.0%	100.0%	98.4%
N-01	Jun-25	78,328	126	1,068	1,128	2.90	3.01	2.80	2.98	5.33	5.40	51.2%	52.1%	96.7%	99.2%
N-01	Jul-25	78,654	126	1,095	1,172	2.83	3.12	2.82	3.12	5.27	5.45	52.1%	50.6%	99.9%	100.0%
N-01	Aug-25	78,996	125	1,118	1,215	2.84	3.24	2.83	3.06	5.32	5.50	52.9%	50.5%	99.6%	94.4%
N-01	Sep-25	79,068	125	839	896	2.33	2.56	2.30	2.50	4.85	5.07	50.0%	48.6%	98.8%	97.8%

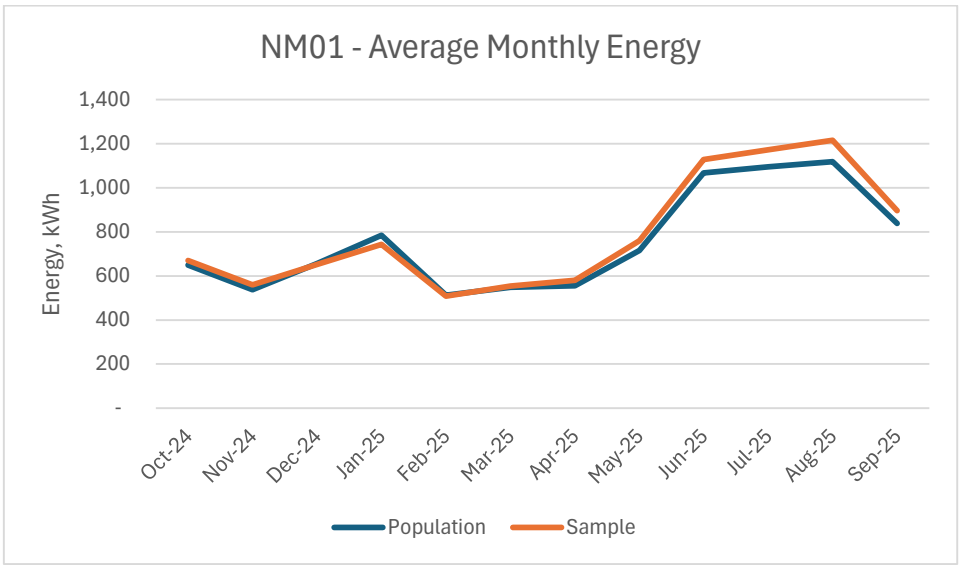
RATE	MONTH	NUMBER OF CUSTOMERS		AVERAGE ENERGY KWH		MAX DIVERSIFIED DEMAND KW		COINCIDENT DEMAND KW		NON-COINCIDENT PEAK KW		LOAD FACTOR % BASED ON MAX		COINCIDENCE FACTOR % BASED ON	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-03	Oct-24	7,530	151	1,765	1,583	4.24	3.76	3.71	2.90	6.81	6.31	55.98%	56.56%	87.57%	77.07%
N-03	Nov-24	7,976	151	1,345	1,346	2.72	2.67	2.38	1.95	5.30	5.15	68.73%	70.12%	87.42%	73.15%
N-03	Dec-24	8,299	151	1,433	1,430	2.72	2.86	2.15	2.08	5.23	5.23	70.81%	67.31%	79.03%	72.68%
N-03	Jan-25	8,543	151	1,598	1,595	3.12	3.32	2.37	2.25	5.49	5.56	68.88%	64.58%	76.02%	67.70%
N-03	Feb-25	8,920	151	1,298	1,298	2.64	2.84	2.00	1.91	5.34	5.32	73.21%	68.05%	75.70%	67.15%
N-03	Mar-25	9,123	150	1,482	1,447	3.10	2.79	2.71	2.29	5.84	5.63	64.36%	69.83%	87.59%	82.18%
N-03	Apr-25	9,339	151	1,511	1,456	3.57	3.42	3.16	2.77	6.29	6.32	58.86%	59.09%	88.57%	80.91%
N-03	May-25	9,558	151	1,804	1,674	4.54	4.21	4.01	3.48	6.92	6.75	53.36%	53.48%	88.29%	82.64%
N-03	Jun-25	9,727	151	2,139	2,023	4.97	4.87	4.35	3.90	7.66	7.45	59.81%	57.72%	87.54%	80.09%
N-03	Jul-25	9,805	150	2,259	2,082	5.01	4.74	4.52	4.09	8.05	7.35	60.61%	59.01%	90.22%	86.14%
N-03	Aug-25	9,876	150	2,281	2,132	5.09	4.75	4.56	4.21	7.74	7.68	60.19%	60.37%	89.50%	88.79%
N-03	Sep-25	9,861	150	1,917	1,797	4.73	4.47	4.15	3.57	7.13	7.02	56.28%	55.77%	87.72%	79.89%

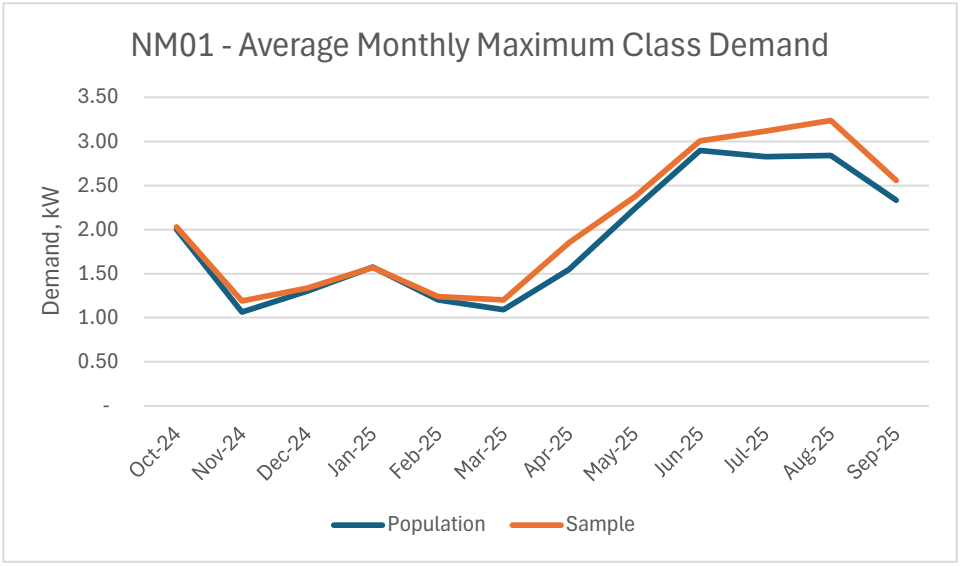
RATE	MONTH	NUMBER OF CUSTOMERS		AVG ENERGY KWH		AVG MAX CLASS DEMAND KW		AVG COINCIDENT DEMAND KW		AVG NON-COINCIDENT PEAK KW		LOAD FACTOR % BASED ON MAX		COINCIDENCE FACTOR % BASED ON	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-04	Oct-24	538	90	40,143	38,353	80.91	77.79	70.53	66.71	106.09	103.17	66.69%	66.27%	87.18%	85.75%
N-04	Nov-24	540	90	32,671	30,976	66.80	67.20	58.05	55.35	89.01	87.93	67.92%	64.02%	86.89%	82.36%
N-04	Dec-24	541	90	33,339	30,366	61.95	60.50	51.47	45.25	87.25	84.27	72.33%	67.47%	83.08%	74.79%
N-04	Jan-25	547	90	35,650	32,263	64.77	62.66	52.96	45.75	90.82	86.21	73.98%	69.21%	81.76%	73.01%
N-04	Feb-25	556	90	30,848	28,585	62.89	63.51	49.10	43.44	90.67	89.00	72.99%	66.97%	78.07%	68.40%
N-04	Mar-25	559	90	34,636	31,026	69.64	66.14	60.32	53.46	94.26	88.90	66.85%	63.05%	86.62%	80.83%
N-04	Apr-25	560	90	35,319	32,973	72.92	69.51	67.02	61.81	99.95	92.79	67.27%	65.88%	91.91%	88.92%
N-04	May-25	568	90	39,357	35,078	83.22	74.41	74.72	63.59	107.48	97.39	63.57%	63.37%	89.79%	85.47%
N-04	Jun-25	569	89	44,537	39,974	91.45	84.56	83.11	72.89	117.90	108.01	67.64%	65.66%	90.89%	86.20%
N-04	Jul-25	579	89	46,403	42,262	89.53	83.80	82.11	74.45	118.43	108.50	69.67%	67.78%	91.71%	88.84%
N-04	Aug-25	577	88	46,714	43,021	95.67	88.49	85.12	76.91	119.91	110.44	65.63%	65.35%	88.97%	86.91%
N-04	Sep-25	579	88	41,618	38,155	88.59	83.26	79.03	70.32	112.29	104.68	65.25%	63.65%	89.21%	84.46%

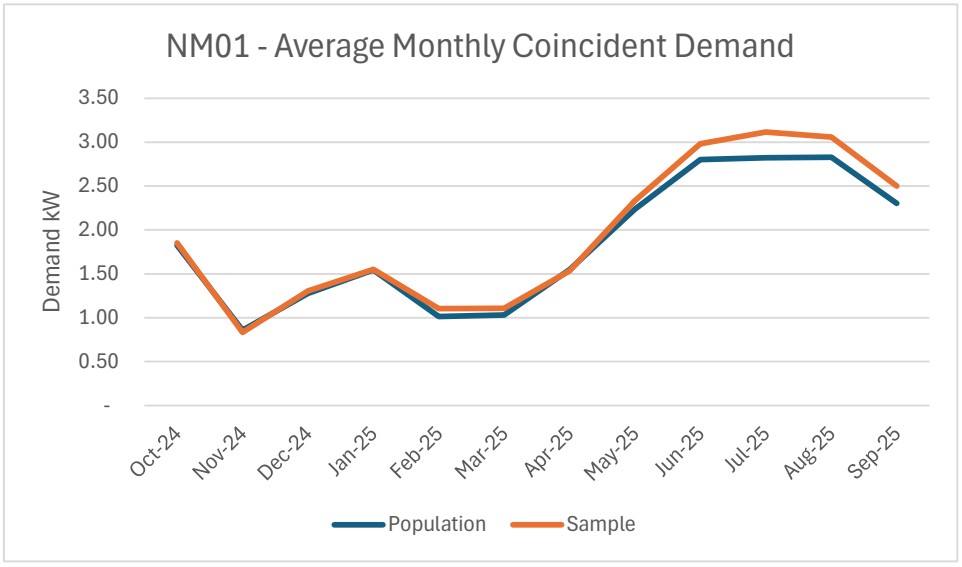
RATE	MONTH	NUMBER OF CUSTOMERS		AVG ENERGY KWH		AVG MAX CLASS DEMAND KW		AVG COINCIDENT DEMAND KW		AVG NON-COINCIDENT PEAK KW		LOAD FACTOR % BASED ON MAX		COINCIDENCE FACTOR % BASED ON	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-05	Oct-24	550	228	7,399	5,769	21.77	17.54	16.32	12.34	47.90	36.58	45.68%	44.22%	74.95%	70.37%
N-05	Nov-24	582	228	1,336	1,191	6.02	5.49	4.04	3.80	15.92	13.89	30.81%	30.14%	67.14%	69.29%
N-05	Dec-24	625	227	1,001	962	3.06	2.81	2.08	1.82	9.03	8.09	43.96%	45.99%	67.83%	64.89%
N-05	Jan-25	680	227	664	664	2.40	2.22	0.45	0.49	8.73	7.79	37.22%	40.20%	18.89%	22.23%
N-05	Feb-25	706	227	2,300	2,283	7.07	6.73	3.69	3.93	18.17	15.88	48.39%	50.48%	52.20%	58.36%
N-05	Mar-25	729	227	4,940	4,731	13.47	11.74	9.39	8.56	34.33	31.62	49.30%	54.18%	69.69%	72.92%
N-05	Apr-25	763	227	6,629	6,675	15.53	15.99	9.71	9.59	38.66	36.42	59.29%	57.96%	62.52%	59.97%
N-05	May-25	797	227	8,034	8,104	16.68	17.88	14.12	13.02	37.76	37.00	64.75%	60.92%	84.66%	72.82%
N-05	Jun-25	804	227	5,560	5,849	12.88	14.30	11.03	11.78	33.69	32.12	59.94%	56.80%	85.62%	82.36%
N-05	Jul-25	803	227	6,949	7,328	17.34	18.86	11.58	12.03	36.86	36.47	53.88%	52.22%	66.80%	63.79%
N-05	Aug-25	805	227	8,676	8,999	19.73	19.33	16.32	17.19	37.21	36.96	59.09%	62.58%	82.70%	88.93%
N-05	Sep-25	806	227	5,556	5,748	15.95	17.56	9.97	9.75	36.61	35.96	48.39%	45.45%	62.51%	55.52%

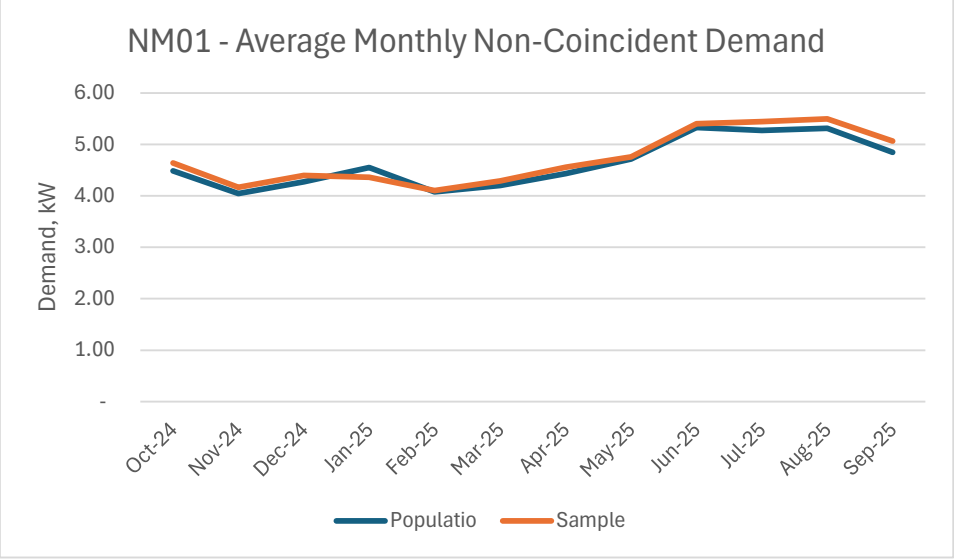
RATE	MONTH	NUMBER OF CUSTOMERS		AVG ENERGY KWH		AVG MAX CLASS DEMAND KW		AVG COINCIDENT DEMAND KW		AVG NON-COINCIDENT PEAK KW		LOAD FACTOR % BASED ON MAX		COINCIDENCE FACTOR % BASED ON	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-07	Oct-24	450	88	9,894	6,053	30.04	17.71	13.52	7.96	34.25	21.69	44.27%	45.94%	45.02%	44.94%
N-07	Nov-24	488	88	7,048	4,805	18.71	12.03	12.62	8.40	23.11	15.54	52.32%	55.49%	67.49%	69.81%
N-07	Dec-24	521	88	6,965	4,986	16.57	11.57	10.78	7.58	21.51	15.52	56.49%	57.90%	65.03%	65.49%
N-07	Jan-25	555	88	7,613	5,813	17.07	12.96	11.71	9.08	21.93	16.67	59.94%	60.27%	68.57%	70.01%
N-07	Feb-25	596	88	6,028	4,951	15.48	12.42	9.37	7.62	19.87	16.72	57.97%	59.30%	60.55%	61.34%
N-07	Mar-25	647	88	5,656	4,959	15.49	13.22	9.99	8.37	19.58	16.96	49.06%	50.44%	64.46%	63.31%
N-07	Apr-25	700	88	5,904	5,573	17.29	15.99	11.13	10.11	20.70	19.64	47.43%	48.40%	64.37%	63.23%
N-07	May-25	703	87	6,544	6,208	20.04	18.87	12.68	11.74	23.33	22.26	43.90%	44.21%	63.30%	62.20%
N-07	Jun-25	708	87	6,856	6,446	18.77	17.01	12.80	11.61	22.30	20.01	50.74%	52.63%	68.22%	68.23%
N-07	Jul-25	711	87	7,591	7,185	22.93	21.67	12.62	11.44	26.58	25.16	44.50%	44.57%	55.05%	52.77%
N-07	Aug-25	713	87	8,686	8,147	25.10	23.50	16.15	14.83	28.62	26.73	46.51%	46.60%	64.33%	63.11%
N-07	Sep-25	704	87	7,648	7,029	23.18	21.51	14.46	12.99	26.50	24.89	45.82%	45.38%	62.39%	60.36%

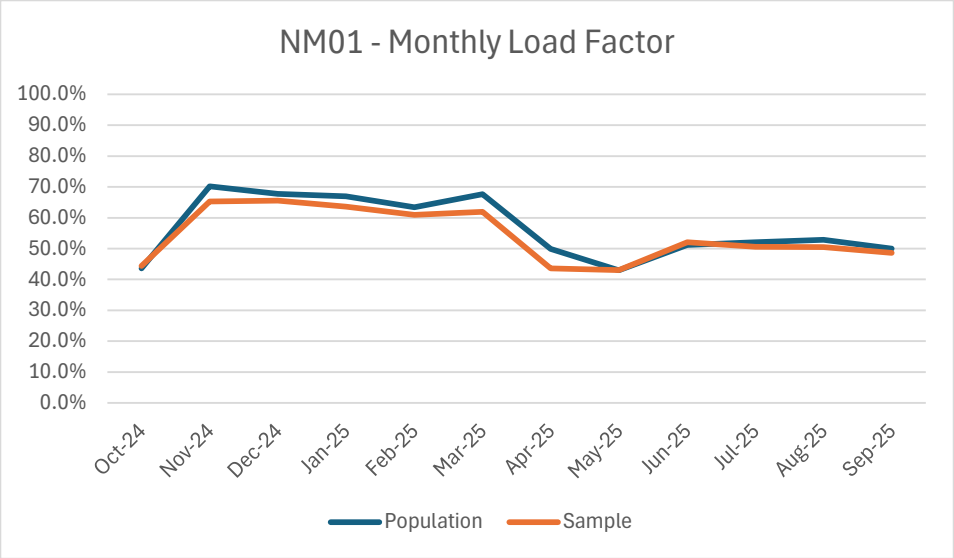
RATE	MONTH	NUMBER OF CUSTOMERS		AVG ENERGY KWH		AVG MAX CLASS DEMAND KW		AVG COINCIDENT DEMAND KW		AVG NON-COINCIDENT PEAK KW		LOAD FACTOR % BASED ON MAX		COINCIDENCE FACTOR % BASED ON	
		POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE
N-08	Oct-24	190	83	16,682	13,225	27.24	22.69	21.04	16.20	45.08	36.38	82.32%	78.33%	77.26%	71.39%
N-08	Nov-24	195	83	13,842	10,574	24.37	19.17	19.23	14.63	43.68	36.21	78.88%	76.60%	78.90%	76.32%
N-08	Dec-24	199	83	13,557	10,311	22.42	19.04	16.83	11.58	41.28	34.07	81.28%	72.78%	75.08%	60.81%
N-08	Jan-25	203	83	13,629	10,620	23.33	19.06	19.16	16.11	40.90	36.59	78.53%	74.90%	82.15%	84.52%
N-08	Feb-25	212	83	11,943	9,683	21.25	20.02	19.25	15.20	37.75	35.57	83.62%	71.95%	90.59%	75.88%
N-08	Mar-25	215	83	13,720	11,459	23.12	22.74	18.91	16.91	39.09	37.11	79.75%	67.74%	81.77%	74.38%
N-08	Apr-25	217	83	15,127	13,045	27.29	25.84	22.70	18.92	41.56	40.53	76.99%	70.11%	83.17%	73.22%
N-08	May-25	223	83	16,828	15,205	28.51	28.16	24.70	23.72	43.18	42.78	79.32%	72.58%	86.63%	84.23%
N-08	Jun-25	225	82	17,109	15,984	29.73	30.80	25.39	23.72	41.90	42.51	79.93%	72.08%	85.41%	77.03%
N-08	Jul-25	226	82	16,263	15,129	27.41	28.89	23.44	22.86	42.64	43.00	79.76%	70.39%	85.54%	79.12%
N-08	Aug-25	225	82	15,976	14,751	26.79	26.62	24.36	23.92	41.91	41.49	80.16%	74.49%	90.94%	89.88%
N-08	Sep-25	225	82	14,318	12,557	27.52	27.68	19.24	16.61	40.35	39.68	72.26%	63.01%	69.92%	60.01%

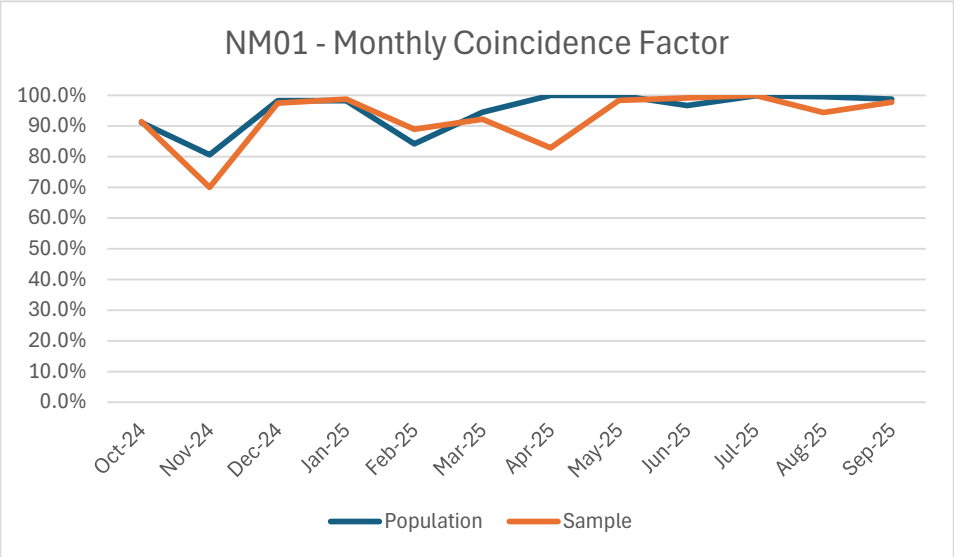

NM01 - Average Monthly Energy
Energy, kWh
1,400
1,200
1,000
800
600
400
200
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

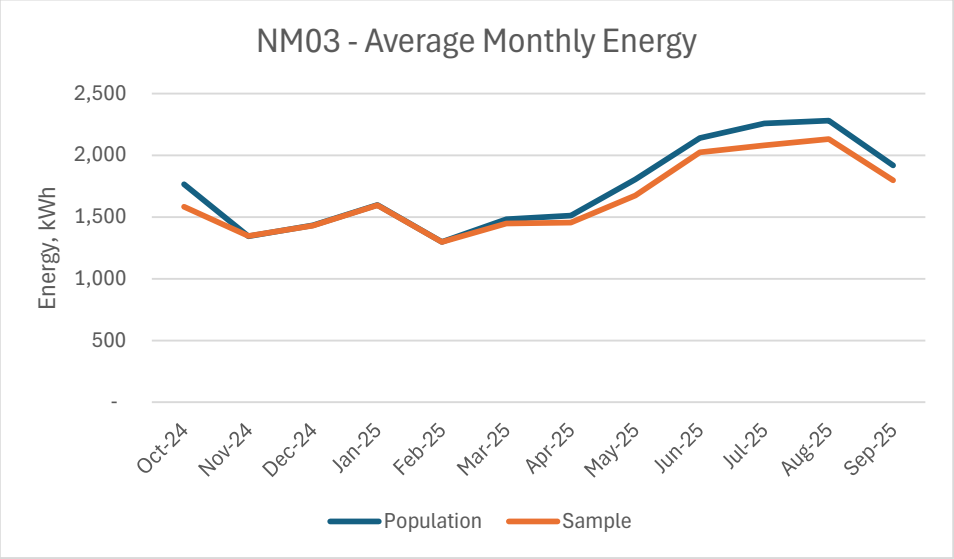

NM01 - Average Monthly Maximum Class Demand
Demand, kW
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

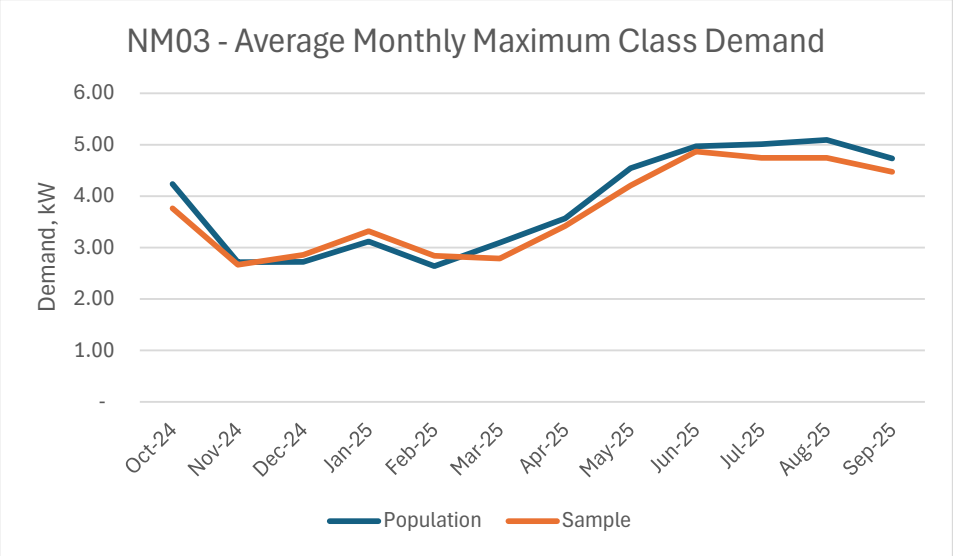

NM01 - Average Monthly Coincident Demand
Demand kW
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

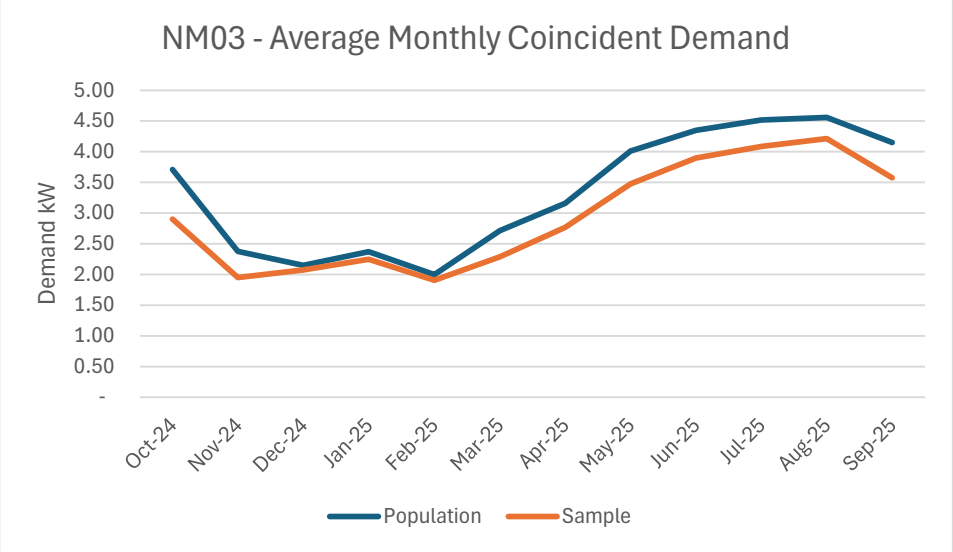

NM01 - Average Monthly Non-Coincident Demand
Demand, kW
6.00
5.00
4.00
3.00
2.00
1.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Populatio
Sample

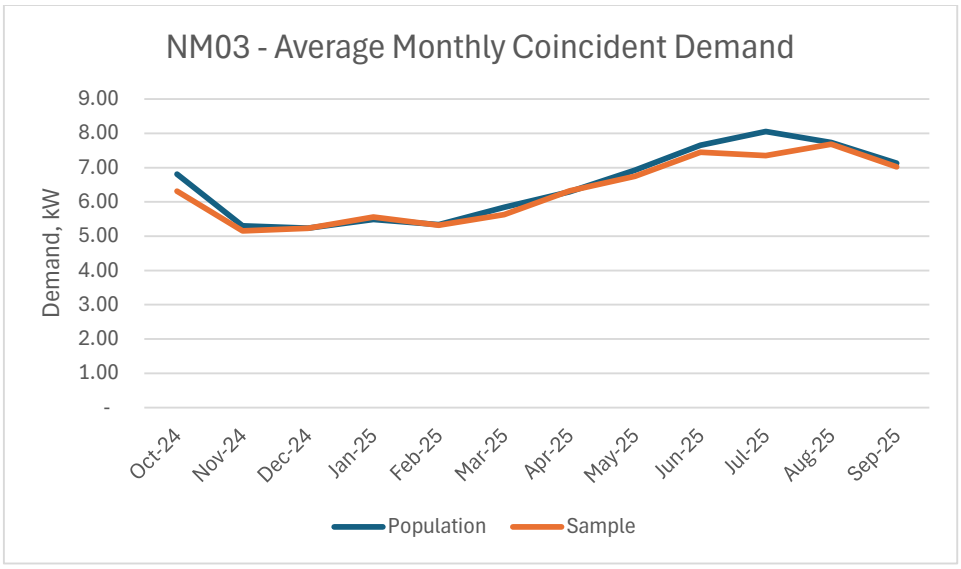

NM01 - Monthly Load Factor
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

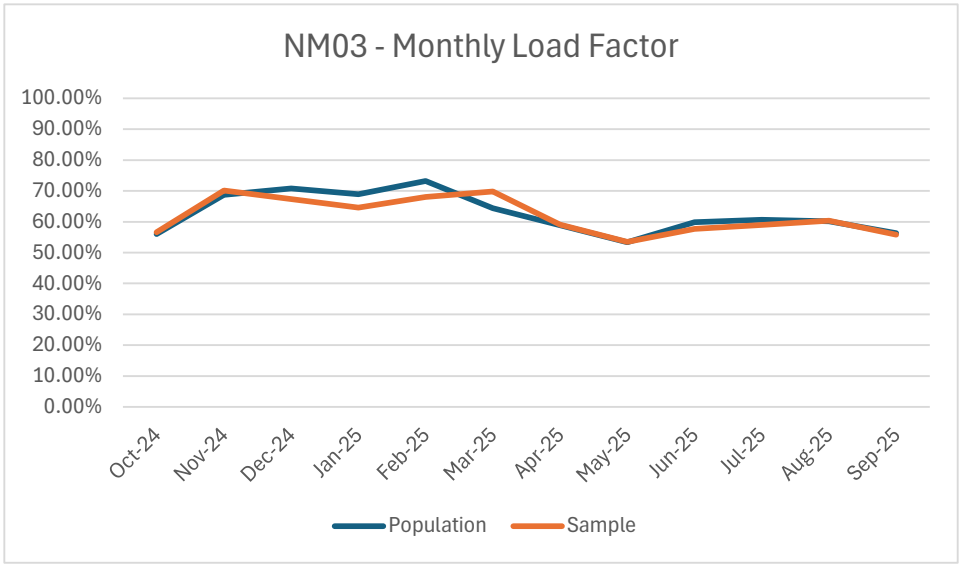

NM01 - Monthly Coincidence Factor
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

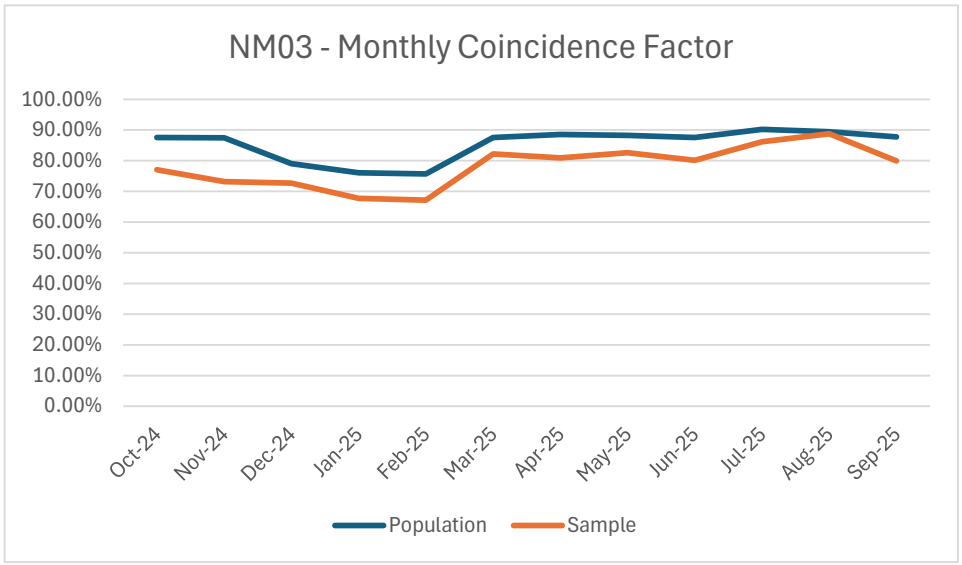

NM03 - Average Monthly Energy
Energy, kWh
2,500
2,000
1,500
1,000
500
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

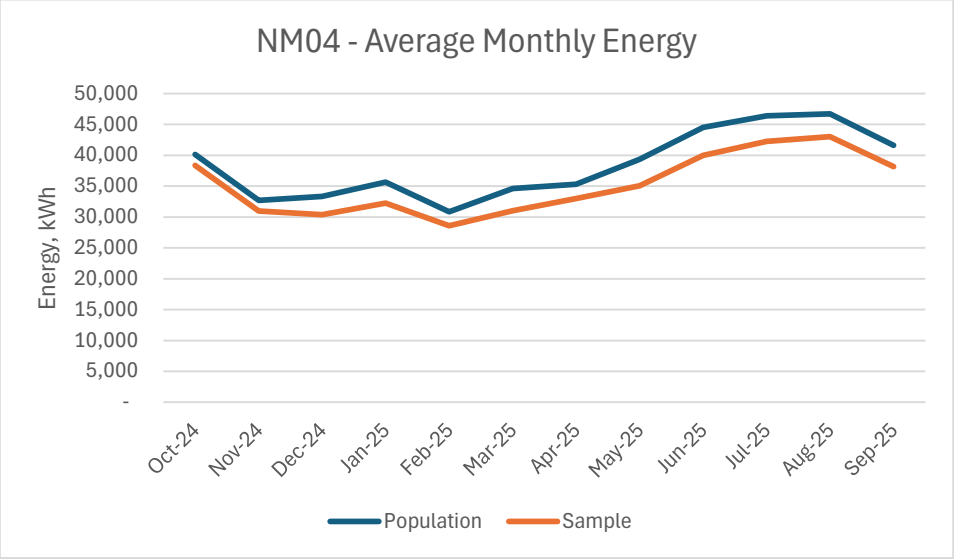

NM03 - Average Monthly Maximum Class Demand
Demand, kW
6.00
5.00
4.00
3.00
2.00
1.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

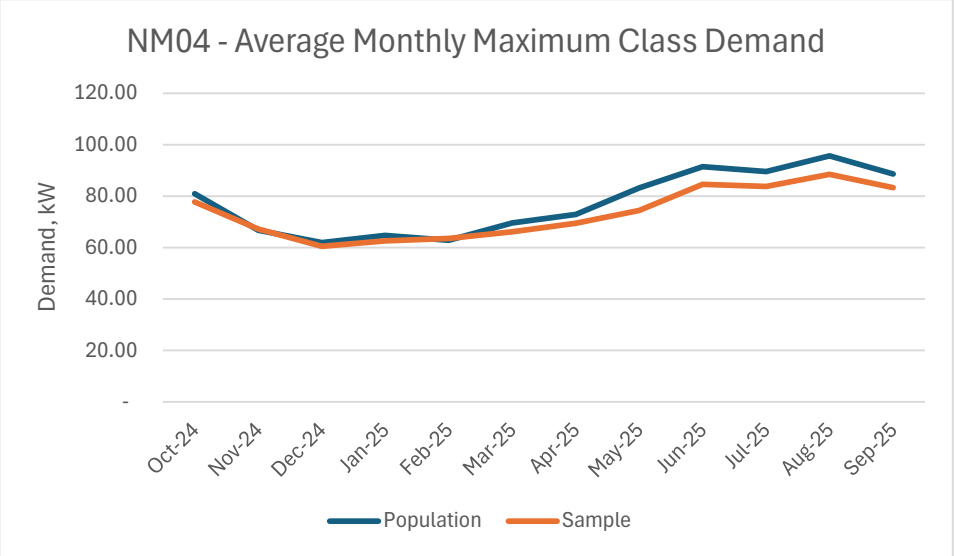

NM03 - Average Monthly Coincident Demand
Demand kW
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

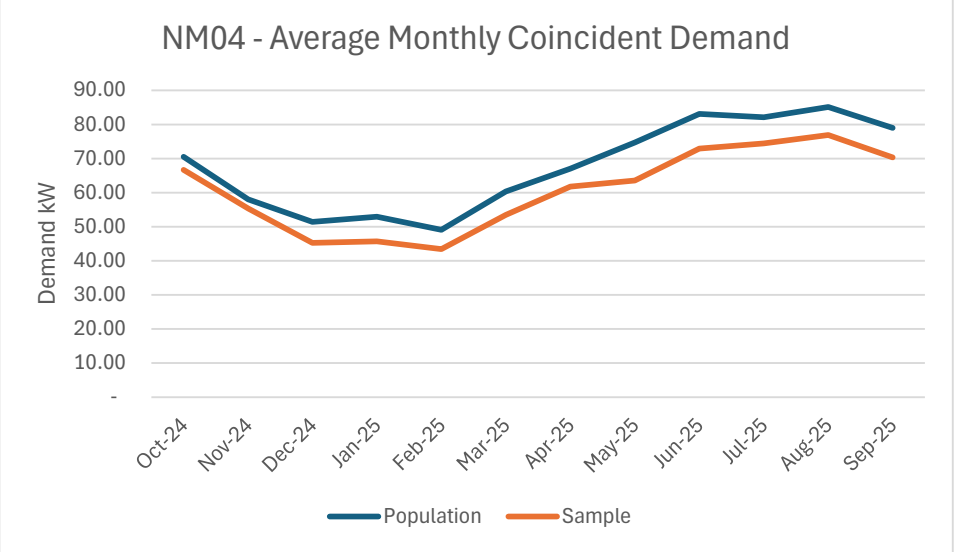

NM03 - Average Monthly Coincident Demand
Demand, kW
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

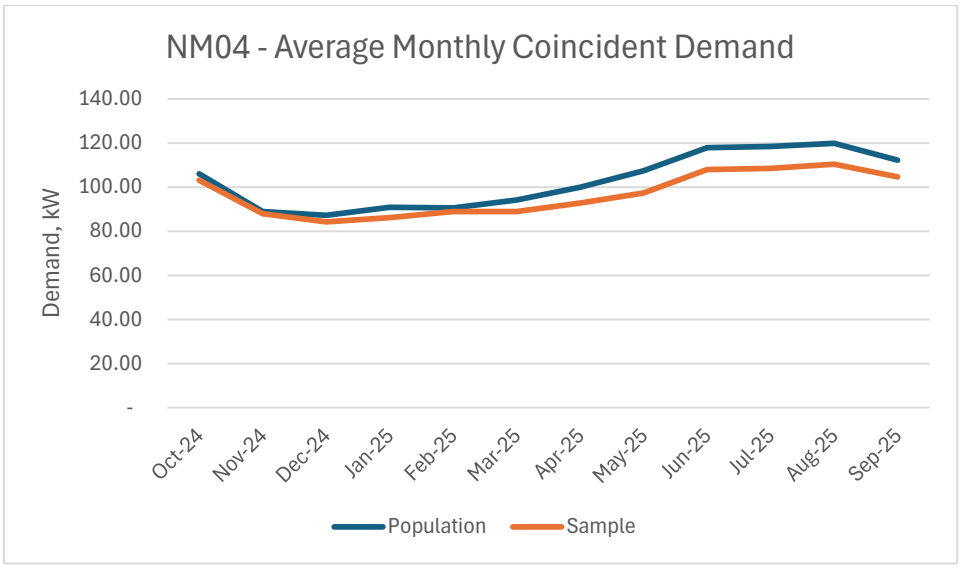

NM03 - Monthly Load Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

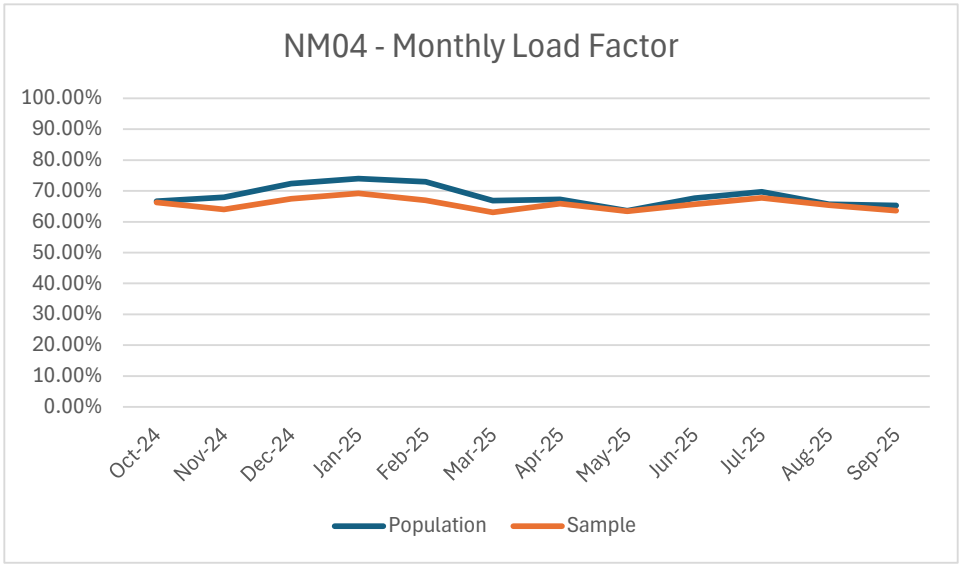

NM03 - Monthly Coincidence Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

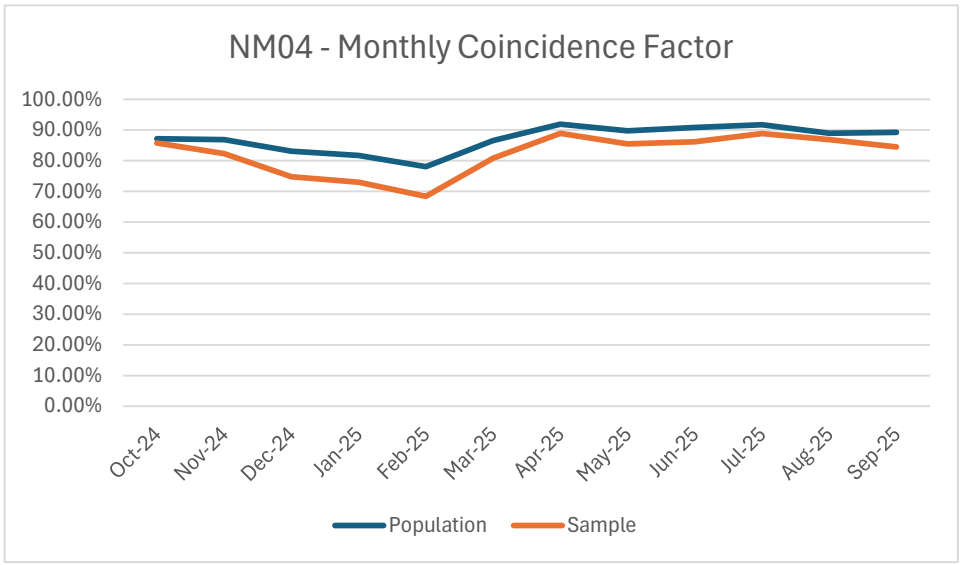

NM04 - Average Monthly Energy
Energy, kWh
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

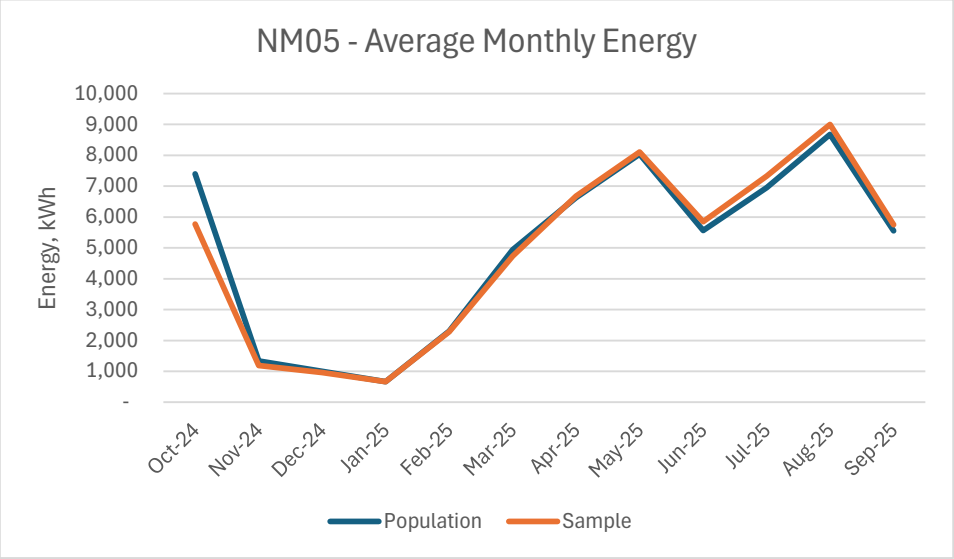

NM04 - Average Monthly Maximum Class Demand
Demand, kW
120.00
100.00
80.00
60.00
40.00
20.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

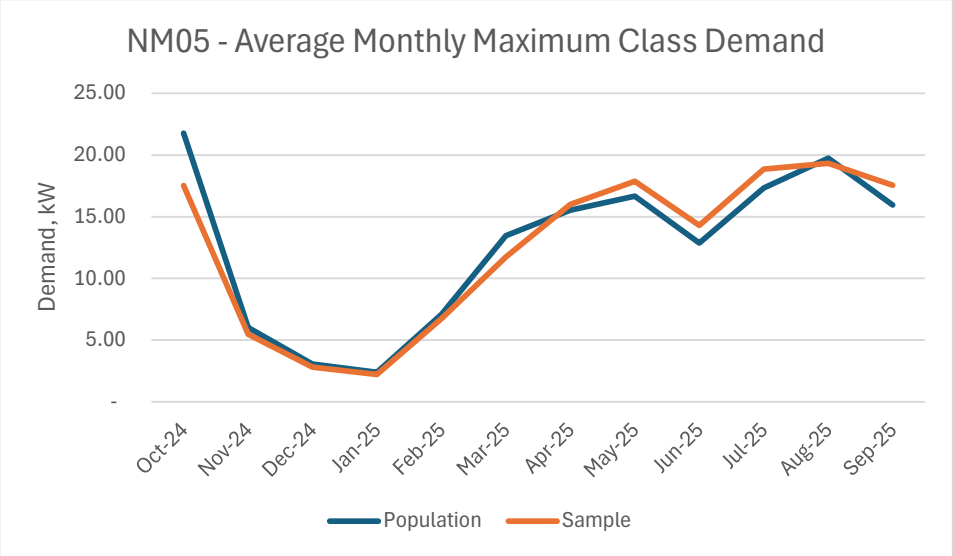

NM04 - Average Monthly Coincident Demand
Demand kW
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

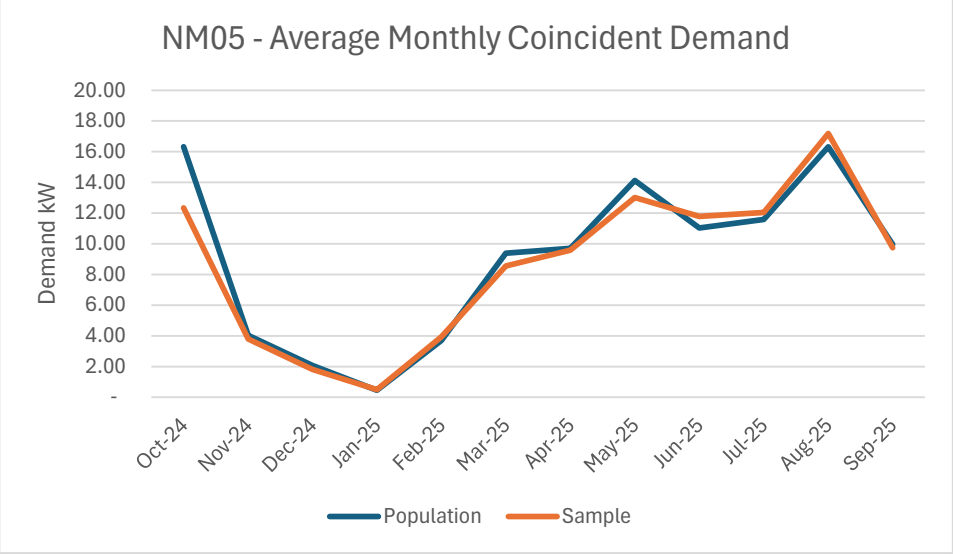

NM04 - Average Monthly Coincident Demand
Demand, kW
140.00
120.00
100.00
80.00
60.00
40.00
20.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

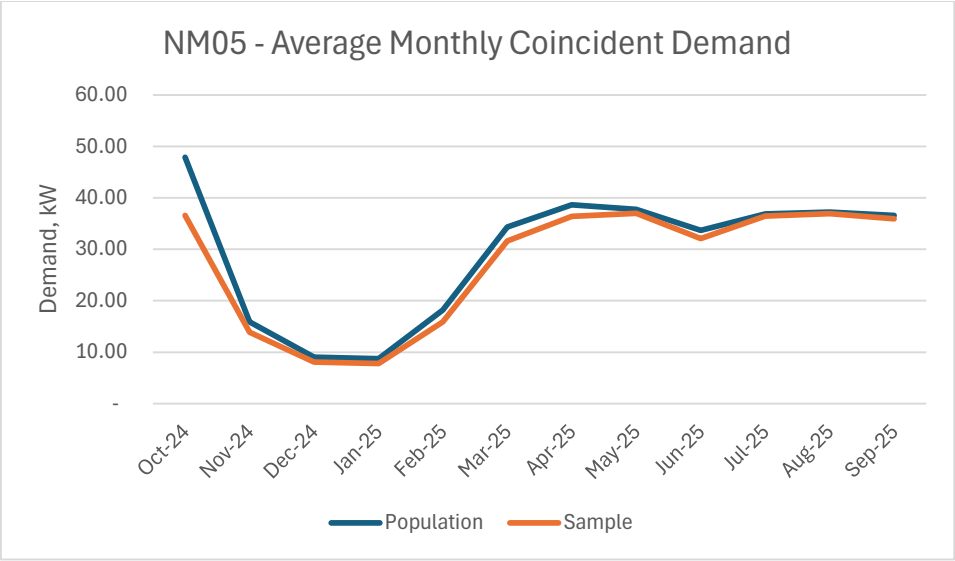

NM04 - Monthly Load Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

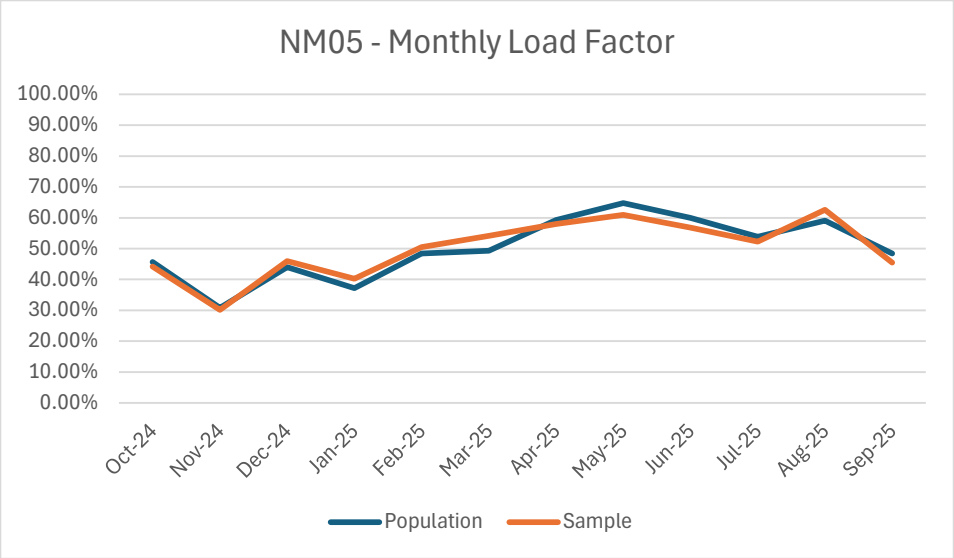

NM04 - Monthly Coincidence Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

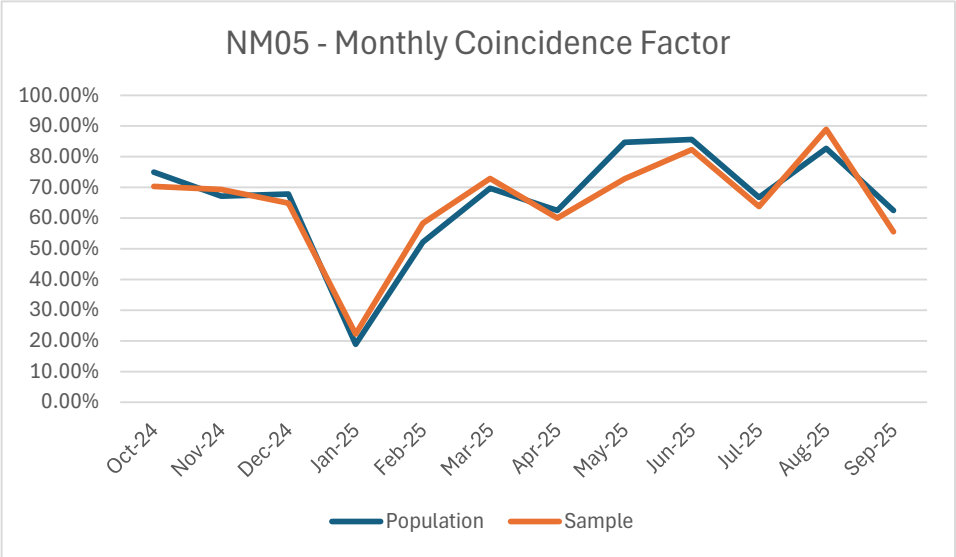

NM05 - Average Monthly Energy
Energy, kWh
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

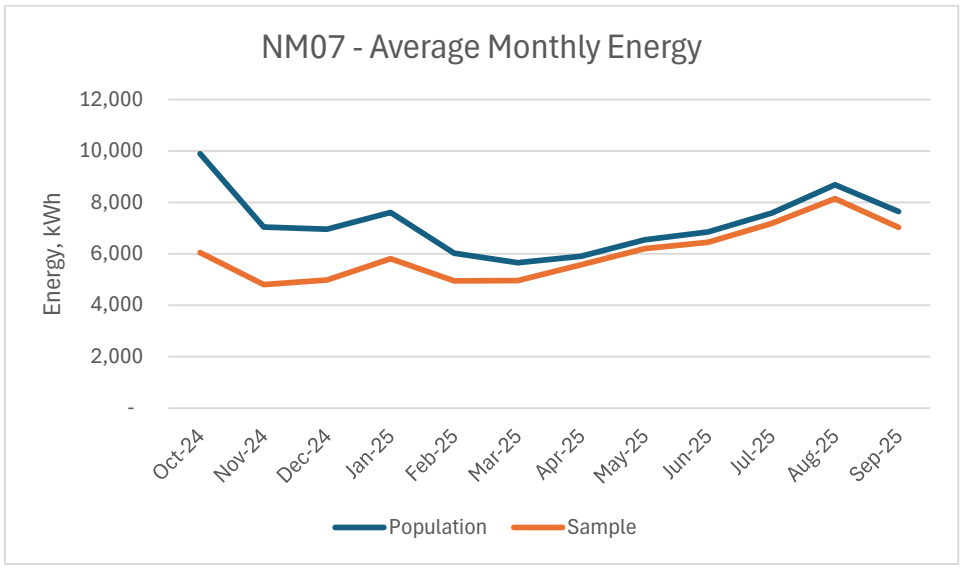

NM05 - Average Monthly Maximum Class Demand
Demand, kW
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

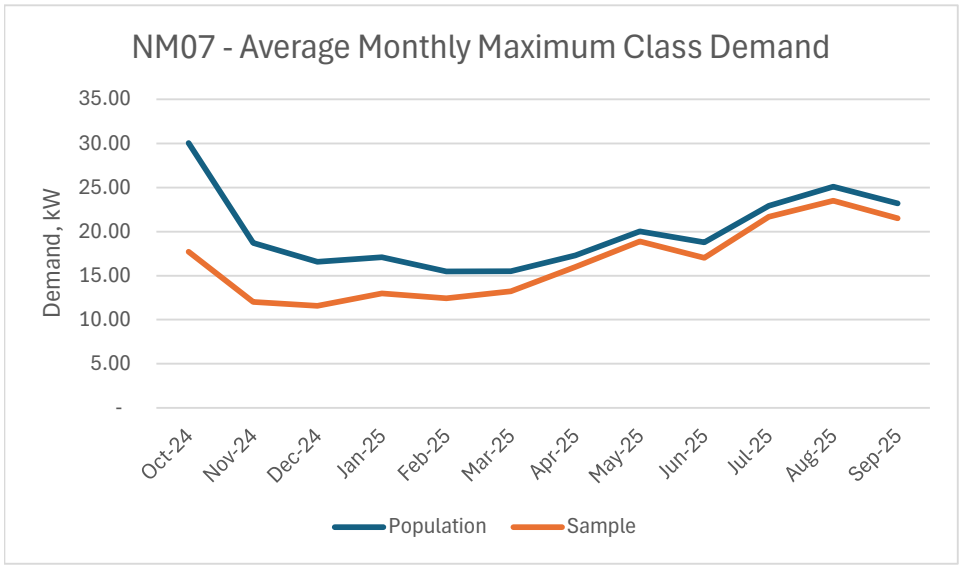

NM05 - Average Monthly Coincident Demand
Demand kW
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

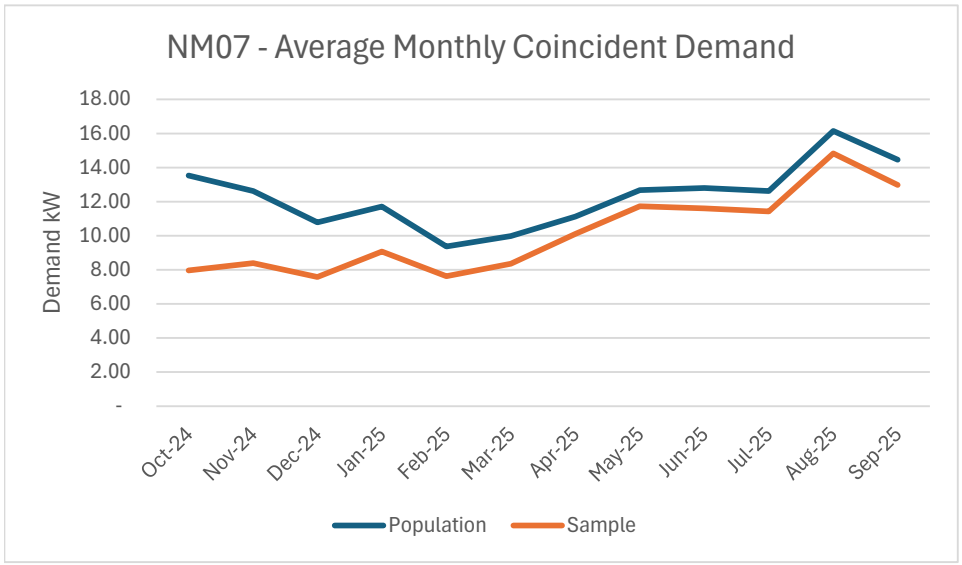

NM05 - Average Monthly Coincident Demand
Demand, kW
60.00
50.00
40.00
30.00
20.00
10.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

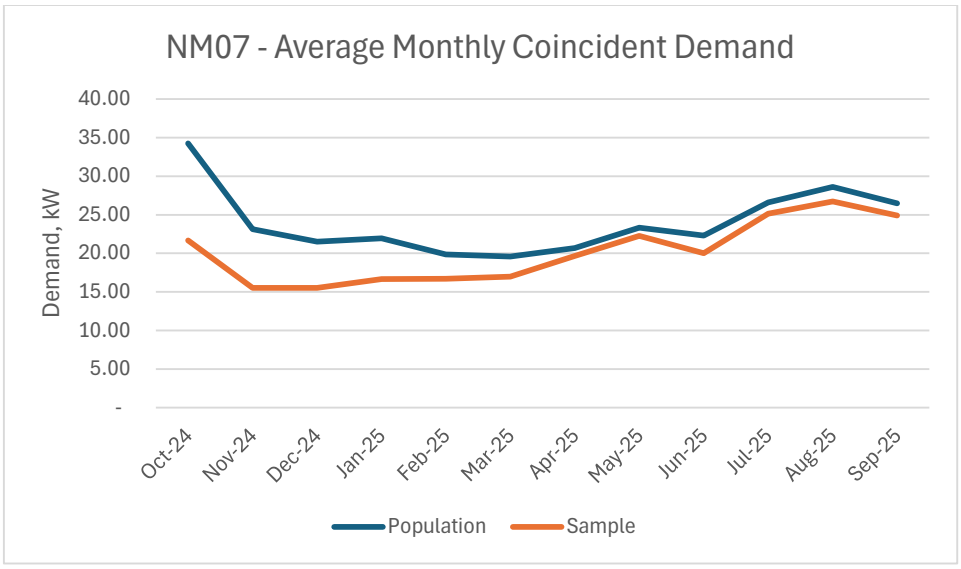

NM05 - Monthly Load Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

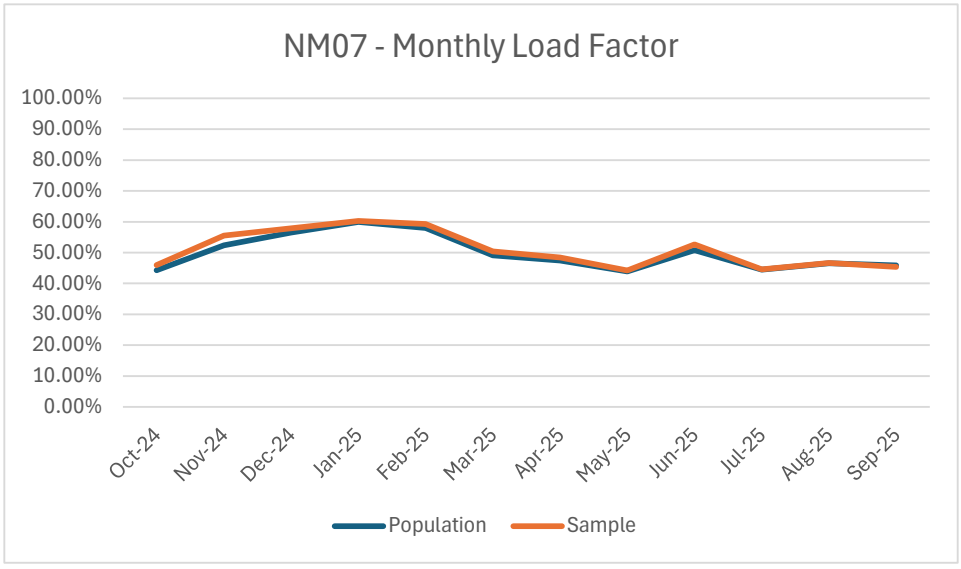

NM05 - Monthly Coincidence Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

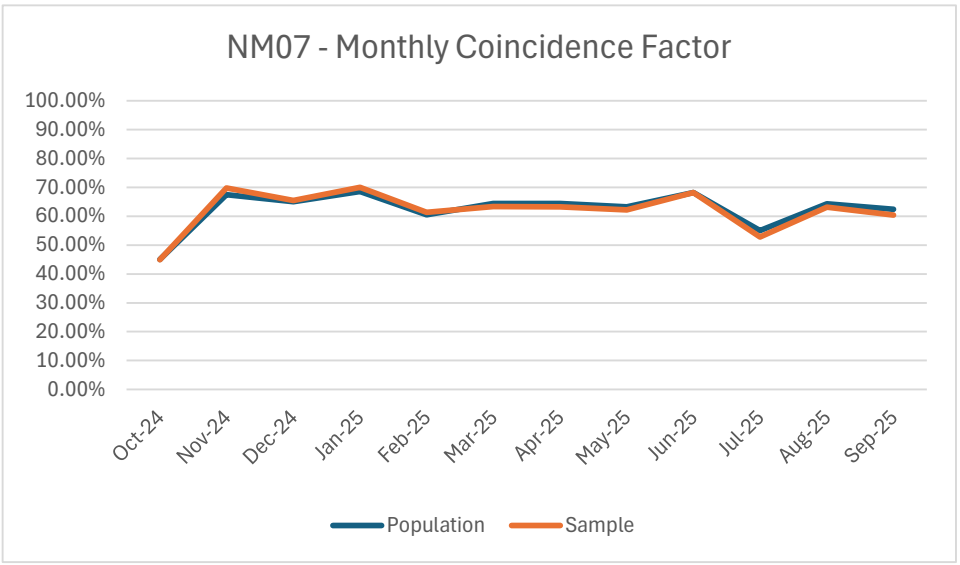

NM07 - Average Monthly Energy
Energy, kWh
12,000
10,000
8,000
6,000
4,000
2,000
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

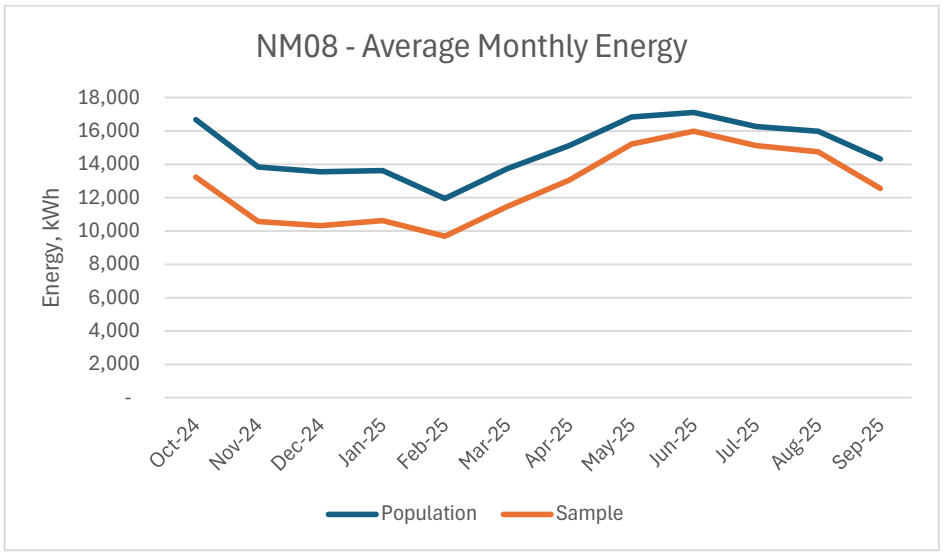

NM07 - Average Monthly Maximum Class Demand
Demand, kW
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

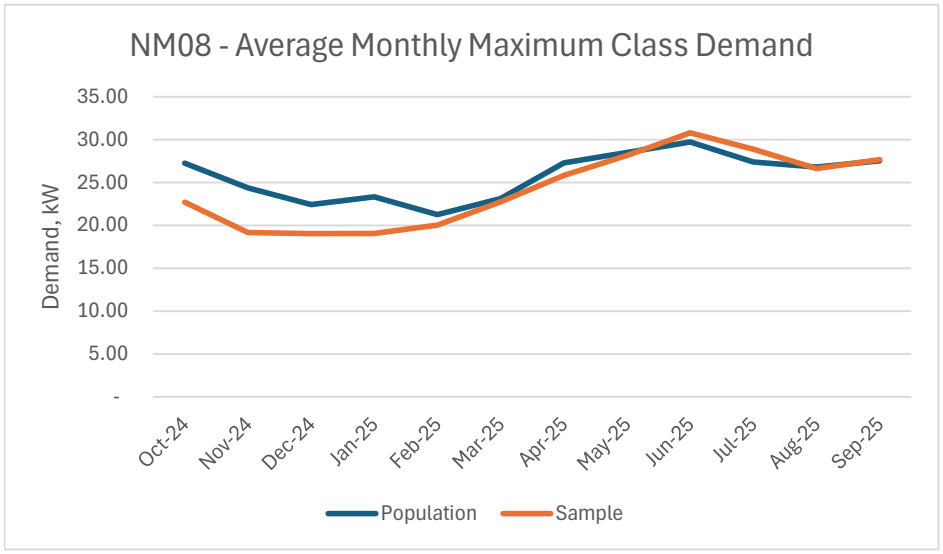

NM07 - Average Monthly Coincident Demand
Demand kW
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

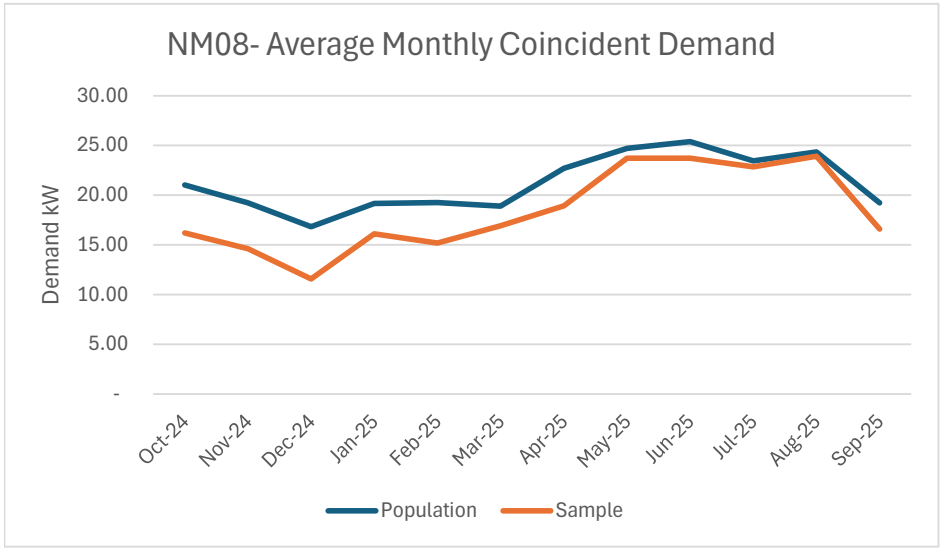

NM07 - Average Monthly Coincident Demand
Demand, kW
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

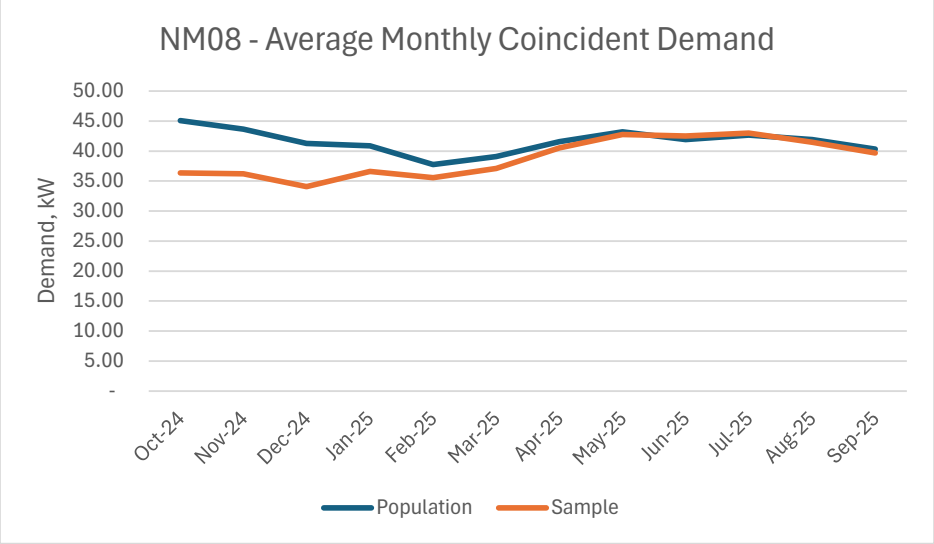

NM07 - Monthly Load Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

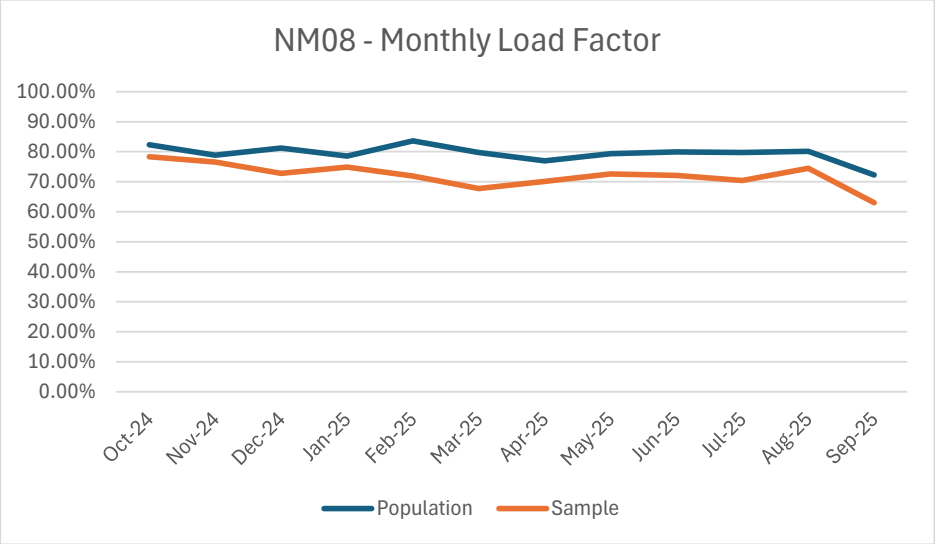

NM07 - Monthly Coincidence Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

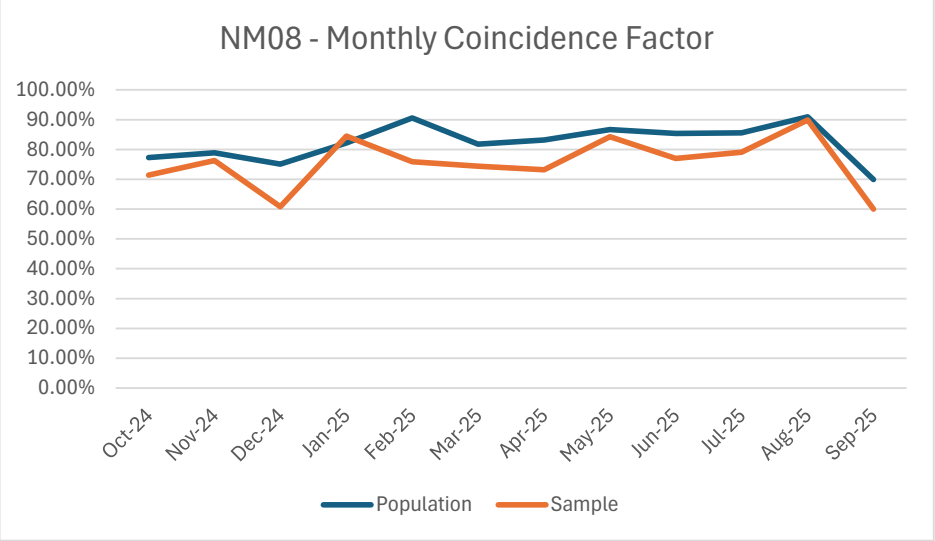

NM08 - Average Monthly Energy
Energy, kWh
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample


NM08 - Average Monthly Maximum Class Demand
Demand, kW
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample


NM08- Average Monthly Coincident Demand
Demand kW
30.00
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample


NM08 - Average Monthly Coincident Demand
Demand, kW
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample


NM08 - Monthly Load Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample


NM08 - Monthly Coincidence Factor
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Oct-24
Nov-24
Dec-24
Jan-25
Feb-25
Mar-25
Apr-25
May-25
Jun-25
Jul-25
Aug-25
Sep-25
Population
Sample

Amended Filing

Exhibit ES-2 - Effect of Using Net Energy for DG Customers on Allocation Factors

Difference in Per Book Jurisdictional Allocators as a result of using Net Energy for DG Customers Prior to the Adjustment for Dedicated Generation Resources (in Percentage Points)

	E1ENERGY	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP
New Mexico	-0.1536%	-0.1455%	-0.1446%	-0.1391%	-0.1510%
Other	0.1536%	0.1455%	0.1446%	0.1391%	0.1510%

Difference in Per Book Jurisdictional Allocators as a result of using Net Energy for DG Customers After the Adjustment for Dedicated Generation Resources (in Percentage Points)

	E1ENERGY	D2PROD 4CP-A&E	D2PROD 4CP	D2PROD 12CP-A&E	D2PROD 12CP
New Mexico	-0.1105%	-0.2524%	-0.2539%	-0.2078%	-0.1678%
Other	0.1105%	0.2524%	0.2539%	0.2078%	0.1678%

Exhibit ES-2
Page 1 of 4

Amended Filing

Exhibit ES-2 - Effect of Using Net Energy for DG Customers on Allocation Factors

Difference in Adjusted Jurisdictional Allocators as a result of using Net Energy for DG Customers Prior to the Adjustment for Dedicated Generation Resources (in Percentage Points)

	E1ENERGY	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP
New Mexico	-0.1491%	-0.1325%	-0.1314%	-0.1296%	-0.1437%
Other	0.1491%	0.1325%	0.1314%	0.1296%	0.1437%

Difference in Adjusted Jurisdictional Allocators as a result of using Net Energy for DG Customers After the Adjustment for Dedicated Generation Resources (in Percentage Points)

	E1ENERGY	D2PROD 4CP-A&E	D2PROD 4CP	D2PROD 12CP-A&E	D2PROD 12CP
New Mexico	-0.1910%	-0.2807%	-0.2815%	-0.5105%	-0.3901%
Other	0.1910%	0.2807%	0.2815%	0.5105%	0.3901%

Exhibit ES-2
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Amended Filing

Exhibit ES-2 - Effect of Using Net Energy for DG Customers on Allocation Factors

Difference in Per Book Class Allocators as a result of using Net Energy for DG Customers (in Percentage Points)

Rate	E1ENERGY	E1FUEL	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP	D3DIST	D4DIST	D5DIST	D6DIST	D7DIST	D8DIST	D9DIST	D10DIST
N-01	-1.1505%	-1.1507%	-0.9361%	-0.9195%	-1.1066%	-1.1568%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-03	0.2355%	0.2332%	0.2307%	0.2311%	0.2669%	0.2619%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-04	0.3567%	0.3535%	0.3107%	0.3081%	0.3980%	0.3942%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-05	0.0627%	0.0622%	0.0600%	0.0601%	0.0634%	0.0647%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-07	0.0621%	0.0615%	0.0625%	0.0627%	0.0827%	0.0765%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-08	-0.0076%	-0.0078%	-0.0002%	-0.0005%	-0.0024%	0.0003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-09	0.2109%	0.2199%	0.1218%	0.1162%	0.1345%	0.1688%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-10 A	0.0843%	0.0836%	0.0568%	0.0552%	0.0596%	0.0711%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-10 B	0.0713%	0.0707%	0.0449%	0.0434%	0.0449%	0.0567%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-11	0.0033%	0.0033%	0.0016%	0.0000%	0.0016%	0.0009%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-12	0.0064%	0.0063%	0.0030%	0.0000%	0.0030%	0.0023%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-19	0.0149%	0.0148%	0.0085%	0.0081%	0.0071%	0.0099%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-25	0.0009%	0.0009%	0.0007%	0.0007%	0.0018%	0.0015%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-26	0.0491%	0.0487%	0.0352%	0.0344%	0.0455%	0.0480%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-42	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Exhibit ES-2 - Effect of Using Net Energy for DG Customers on Allocation Factors

Difference in Adjusted Class Allocators as a result of using Net Energy for DG Customers (in Percentage Points)

Rate	E1ENERGY	E1FUEL	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP	D3DIST	D4DIST	D5DIST	D6DIST	D7DIST	D8DIST	D9DIST	D10DIST
N-01	-1.1465%	-1.1466%	-0.9068%	-0.8831%	-1.0937%	-1.1470%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-03	0.2308%	0.2286%	0.2220%	0.2221%	0.2606%	0.2559%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-04	0.3594%	0.3562%	0.3017%	0.2970%	0.3966%	0.3941%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-05	0.0619%	0.0614%	0.0574%	0.0573%	0.0621%	0.0635%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-07	0.0609%	0.0603%	0.0598%	0.0599%	0.0808%	0.0747%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-08	-0.0098%	-0.0100%	-0.0005%	-0.0009%	-0.0036%	-0.0012%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-09	0.2135%	0.2223%	0.1174%	0.1093%	0.1340%	0.1696%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-10 A	0.0841%	0.0834%	0.0555%	0.0532%	0.0588%	0.0705%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-10 B	0.0712%	0.0706%	0.0454%	0.0433%	0.0463%	0.0575%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-11	0.0033%	0.0033%	0.0015%	0.0000%	0.0015%	0.0009%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-12	0.0063%	0.0063%	0.0029%	0.0000%	0.0029%	0.0023%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-19	0.0151%	0.0150%	0.0085%	0.0079%	0.0070%	0.0100%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-25	0.0009%	0.0009%	0.0006%	0.0006%	0.0018%	0.0014%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-26	0.0489%	0.0484%	0.0344%	0.0333%	0.0448%	0.0475%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
N-42	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Adjusted Jurisdictional Allocators - Large Load Scenario
Prior to the Adjustment for Assigned Generation Resources

	E1ENERGY	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP
New Mexico	28.7929%	27.1608%	27.2560%	28.1659%	28.4335%
Other	71.2071%	72.8392%	72.7440%	71.8341%	71.5665%
Total	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Adjusted Jurisdictional Allocators - Large Load Scenario
After the Adjustment for Assigned Generation Resources

	E1ENERGY	D2PROD 4CP-A&E	D2PROD 4CP	D2PROD 12CP-A&E	D2PROD 12CP
New Mexico	35.3960%	26.8052%	26.8523%	25.0802%	28.2733%
Other	64.6040%	73.1948%	73.1477%	74.9198%	71.7267%
Total	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Adjusted Jurisdiction Class Allocators - Large Load Scenario

No.	Rate	Description	E1ENERGY Energy Allocator	E1FUEL Allocator	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP	D3DIST - Allocator	D4DIST, D7DIST, D9DIST Allocator	D5DIST Allocator	D6DIST, D10DIST Allocator	D8DIST Allocator
1	NMRT01	Residential Service	32.2763%	32.1803%	47.8446%	47.0986%	45.6087%	40.8699%	58.2686%	58.2686%	66.4642%	66.4642%	66.4642%
2	NMRT03	Small General Service	7.8714%	7.8480%	8.9392%	8.8958%	8.3637%	8.1959%	11.1154%	11.1154%	11.7844%	11.7844%	11.7844%
3	NMRT04	General Service	11.4697%	11.4356%	10.8037%	10.8533%	11.6254%	11.5819%	13.3427%	13.3427%	10.3267%	10.3267%	10.3267%
4	NMRT05	Irrigation Service	1.7787%	1.7734%	2.0153%	2.0058%	1.7403%	1.7559%	3.1912%	3.1912%	4.1040%	4.1040%	4.1040%
5	NMRT07	City and County Service	2.1216%	2.1153%	2.4667%	2.4521%	2.6142%	2.4401%	4.4301%	4.4301%	3.3848%	3.3848%	3.3848%
6	NMRT08	Municipal Pumping Service	1.5292%	1.5247%	0.9591%	0.9901%	0.8307%	1.0824%	1.4455%	1.4455%	1.0808%	1.0808%	1.0808%
7	NMRT09	Large Power Service	5.9507%	6.2304%	3.5971%	3.7248%	3.7799%	4.5635%	4.6071%	4.6071%	1.7095%	1.7095%	1.7095%
8	NMRT10	Military Research & Development Service WSMR	1.9867%	1.9808%	1.5217%	1.5480%	1.4042%	1.6148%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
9	NMRT10-T115A	Military Research & Development Service ALA	0.3581%	0.3570%	0.2601%	0.2656%	0.2397%	0.2824%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
10	NMRT10 -T115	Military Research & Development Service HAFB	1.9852%	1.9793%	1.4456%	1.4757%	1.3011%	1.5481%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
11	NMRT11	Municipal Street Lighting Service	0.0920%	0.0917%	0.0447%	0.0000%	0.0447%	0.0248%	0.0846%	0.0846%	0.0568%	0.0568%	0.0568%
12	NMRT12	Private Area Lighting Service	0.1764%	0.1759%	0.0857%	0.0000%	0.0857%	0.0612%	0.2077%	0.2077%	0.1395%	0.1395%	0.1395%
13	NMRT19	Seasonal-Agricultural Processing Service	0.4216%	0.4203%	0.2610%	0.2697%	0.2049%	0.2700%	0.9806%	0.9806%	0.8281%	0.8281%	0.8281%
14	NMRT25	Outdoor Recreational Lighting Service	0.0243%	0.0242%	0.0209%	0.0211%	0.0469%	0.0388%	0.1324%	0.1324%	0.1211%	0.1211%	0.1211%
15	NMRT26	State University Service	1.3618%	1.3577%	1.1215%	1.1356%	1.2292%	1.2781%	2.1940%	2.1940%	0.0000%	0.0000%	0.0000%
16	NMRT42 - S	Experimental EV Charging	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
17	NMRT50	Large Load High Load Factor (Proposed Rate 50)	27.0203%	26.9400%	15.1980%	15.8355%	16.3733%	20.2141%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
18	NMRT51	Large Load Power (Proposed Rate 51)	3.5762%	3.5656%	3.4152%	3.4283%	4.5075%	4.1779%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Adjusted Jurisdictional Allocators - NM07 Scenario
Prior to the Adjustment for Assigned Generation Resources

	E1ENERGY	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP
New Mexico	21.9230%	23.1375%	23.2303%	23.6460%	23.1057%
Other	78.0770%	76.8625%	76.7697%	76.3540%	76.8943%
Total	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Adjusted Jurisdictional Allocators - NM07 Scenario
After the Adjustment for Assigned Generation Resources

	E1ENERGY	D2PROD 4CP-A&E	D2PROD 4CP	D2PROD 12CP-A&E	D2PROD 12CP
New Mexico	24.1909%	20.4547%	20.4938%	16.7993%	19.1272%
Other	75.8091%	79.5453%	79.5062%	83.2007%	80.8728%
Total	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Adjusted Jurisdiction Class Allocators - NM07 Scenario

No.	Rate	Description	E1ENERGY Energy Allocator	E1FUEL Allocator	D1PROD 4CP-A&E	D2TRAN 4CP	D1PROD 12CP-A&E	D2TRAN 12CP	D3DIST - Allocator	D4DIST, D7DIST, D9DIST Allocator	D5DIST Allocator	D6DIST, D10DIST Allocator	D8DIST Allocator
1	NMRT01	Residential Service	46.4944%	46.2955%	57.6454%	58.3132%	56.8298%	54.0440%	58.0187%	58.0187%	66.3424%	66.3424%	66.3424%
2	NMRT03	Small General Service	11.1167%	11.0692%	10.8143%	10.8173%	10.4197%	10.6278%	10.8578%	10.8578%	11.5397%	11.5397%	11.5397%
3	NMRT04	General Service	15.3806%	15.3148%	12.6115%	12.4916%	13.8533%	14.2965%	12.0845%	12.0845%	9.4317%	9.4317%	9.4317%
4	NMRT05	Irrigation Service	2.5627%	2.5518%	2.4841%	2.4844%	2.2259%	2.3224%	3.1790%	3.1790%	4.0984%	4.0984%	4.0984%
5	NMRT07	City and County Service	4.4389%	4.4199%	4.2169%	4.2128%	4.4765%	4.4724%	6.2449%	6.2449%	4.6571%	4.6571%	4.6571%
6	NMRT08	Municipal Pumping Service	2.2033%	2.1938%	1.2717%	1.2264%	1.1332%	1.4316%	1.4400%	1.4400%	1.0793%	1.0793%	1.0793%
7	NMRT09	Large Power Service	8.5738%	8.9650%	4.7982%	4.6136%	5.0519%	6.0357%	4.5895%	4.5895%	1.7072%	1.7072%	1.7072%
8	NMRT10	Military Research & Development Service WSMR	2.8624%	2.8502%	1.9601%	1.9174%	1.8533%	2.1358%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
9	NMRT10-T115A	Military Research & Development Service ALA	0.5160%	0.5137%	0.3375%	0.3289%	0.3183%	0.3736%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
10	NMRT10 -T115	Military Research & Development Service HAFB	2.8602%	2.8480%	1.8749%	1.8278%	1.7323%	2.0476%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
11	NMRT11	Municipal Street Lighting Service	0.1325%	0.1319%	0.0620%	0.0000%	0.0620%	0.0329%	0.0843%	0.0843%	0.0568%	0.0568%	0.0568%
12	NMRT12	Private Area Lighting Service	0.2541%	0.2531%	0.1189%	0.0000%	0.1189%	0.0809%	0.2069%	0.2069%	0.1394%	0.1394%	0.1394%
13	NMRT19	Seasonal-Agricultural Processing Service	0.6074%	0.6048%	0.3468%	0.3340%	0.2842%	0.3571%	0.9769%	0.9769%	0.8270%	0.8270%	0.8270%
14	NMRT25	Outdoor Recreational Lighting Service	0.0350%	0.0348%	0.0265%	0.0261%	0.0575%	0.0513%	0.1319%	0.1319%	0.1209%	0.1209%	0.1209%
15	NMRT26	State University Service	1.9621%	1.9537%	1.4312%	1.4065%	1.5831%	1.6904%	2.1856%	2.1856%	0.0000%	0.0000%	0.0000%
16	NMRT42 - S	Experimental EV Charging	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
			100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Exhibit ES-4 Historical Weather in Las Cruces, NM and El Paso, TX

Las Cruces			El Paso			Percent Difference LC vs. EP		
Year	HDD	CDD	Year	HDD	CDD	Year	HDD	CDD
2010	3,090	1,859	2010	2,354	2,739	2010	31%	-32%
2011	3,108	2,109	2011	2,473	3,143	2011	26%	-33%
2012	2,664	2,005	2012	2,088	2,878	2012	28%	-30%
2013	3,209	1,976	2013	2,501	2,697	2013	28%	-27%
2014	2,663	1,960	2014	1,979	2,671	2014	35%	-27%
2015	2,911	1,949	2015	2,185	2,838	2015	33%	-31%
2016	2,659	2,015	2016	1,920	2,812	2016	38%	-28%
2017	2,259	2,005	2017	1,589	2,925	2017	42%	-31%
2018	2,640	2,335	2018	2,017	3,176	2018	31%	-26%
2019	2,722	2,105	2019	2,208	3,010	2019	23%	-30%
2020	2,676	2,383	2020	2,073	3,311	2020	29%	-28%
2021	2,377	2,057	2021	1,950	2,693	2021	22%	-24%
2022	2,934	2,279	2022	2,396	2,937	2022	22%	-22%
2023	2,476	2,614	2023	1,985	3,537	2023	25%	-26%
2024	2,191	2,639	2024	1,728	3,515	2024	27%	-25%
2025*	1,783	1,963	2025*	1,210	2,946	2025*	47%	-33%
Average (2010-2024)	2,705	2,153	Average (2010-2024)	2,096	2,992	Average (2010-2024)	29%	-28%

*Note: Data for 2025 are shown through the end of the Base Period, September 2025

Amended Filing

EL PASO ELECTRIC COMPANY
WEATHER DATA AND COEFFICIENTS
FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2025

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
Actual Weather												
El Paso												
HDD-2MA	5	129	323	542	461	213	144	49	1	0	0	0
CDD-2MA	378	147	2	0	0	20	103	260	492	632	658	562
Las Cruces												
HDD-2MA	11	213	418	643	613	366	267	99	12	0	0	0
CDD-2MA	246	72	0	0	0	2	29	112	320	475	494	393
10-Year Avg Weather for (2014-2023) & 2025 (2015-2024)												
El Paso												
HDD-2MA	29	168	401	547	472	277	112	24	1	0	0	1
CDD-2MA	288	85	6	0	1	14	84	255	496	651	649	526
Las Cruces												
HDD-2MA	55	250	505	636	553	363	186	55	7	0	0	2
CDD-2MA	182	34	1	0	0	3	33	136	357	539	537	404

Coefficients	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
TXRT01- Residential	0.8633	0.2948	0.2472	0.3624	0.2236	0.1512	0.3310	0.5021	0.7521	0.9086	0.9060	0.9802
TXRT02- Small General	15,821							9,752	15,145	18,802	18,231	20,135
TXRT22- Irrigation	313							322	429	318	260	278
TXRT24- General Service	89,923							52,991	69,763	85,583	75,480	91,405
TXRT31- Military									8,663	6,404	6,284	5,849
TXRT41- City & County	13,459							9,172	8,042	4,655	12,548	19,161
NMRT01- Residential	0.9600	0.1466	0.2791	0.4292	0.2962	0.1880	0.1651	0.5987	0.8507	0.9719	0.9655	1.0881
NMRT03- Small General	14,819							6,828	10,509	12,320	12,213	14,473
NMRT04- General Service	20,138							10,662	13,584	15,257	15,710	19,732
NMRT05- Irrigation	5,239							8,680	4,363	2,323	2,496	3,726
NMRT07- City & County	6,306							3,566	2,283	2,106	3,601	6,422
NMRT08- Water Sewage Storm Pumping or Sewage Disposal	1,169							3,045	2,249	2,106	1,773	2,430
NMRT10-Military Research & Development									7,909	7,136	7,692	7,500
NMRT26-State University	4,320							3,533	2,622	2,490	2,714	4,162

Number of Customers for UPC Models	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
TXRT01- Residential	320,860	320,653	321,037	321,208	321,436	321,882	322,224	323,126	323,916	324,669	324,862	325,145
NMRT01- Residential	96,418	96,455	96,570	96,692	96,742	96,896	97,036	97,129	97,249	97,488	97,546	97,650

Amended Filing

EL PASO ELECTRIC COMPANY
WEATHER DATA AND COEFFICIENTS
FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2025

EXHIBIT ES-5
PAGE 2 OF 3

Description	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Test Year Total
Weather Adjustments to kWh													
TXRT01- Residential	(24,928,791)	3,686,437	6,190,933	582,014	790,724	3,115,797	(3,413,203)	(811,230)	974,523	5,604,780	(2,649,018)	(11,473,609)	(22,330,642)
TXRT02- Small Commercial	(1,423,918)	0	0	0	0	0	0	(48,758)	60,579	357,244	(164,082)	(724,866)	(1,943,801)
TXRT22- Irrigation	(28,213)	0	0	0	0	0	0	(1,608)	1,715	6,040	(2,343)	(10,023)	(34,431)
TXRT24- General Service	(8,093,071)	0	0	0	0	0	0	(264,953)	279,052	1,626,075	(679,319)	(3,290,578)	(10,422,794)
TXRT31- Military	0	0	0	0	0	0	0	0	34,650	121,675	(56,560)	(210,567)	(110,801)
TXRT41- City & County	(1,211,302)	0	0	0	0	0	0	(45,859)	32,166	88,446	(112,928)	(689,814)	(1,939,291)
Total Weather Adjustment	(35,685,295)	3,686,437	6,190,933	582,014	790,724	3,115,797	(3,413,203)	(1,172,409)	1,382,685	7,804,260	(3,664,250)	(16,399,456)	(36,781,761)

EL PASO ELECTRIC COMPANY
WEATHER DATA AND COEFFICIENTS
FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2025

Description	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Test Year Total**
Weather Adjustments to kWh													
NMRT01- Residential	(5,923,848)	523,195	2,345,186	(290,487)	(1,719,276)	(54,639)	(1,297,326)	1,395,583	3,061,079	6,063,866	4,049,756	1,168,817	9,321,906
NMRT03- Small General	(948,406)	0	0	0	0	0	0	163,864	388,845	788,472	525,169	159,205	1,077,149
NMRT04- General Service	(1,288,812)	0	0	0	0	0	0	255,891	502,590	976,444	675,544	217,047	1,338,703
NMRT05- Irrigation	(335,280)	0	0	0	0	0	0	208,322	161,418	148,696	107,338	40,983	331,476
NMRT07- City & County	(403,585)	0	0	0	0	0	0	85,592	84,462	134,774	154,860	70,641	126,744
NMRT08- Pumping	(74,828)	0	0	0	0	0	0	73,086	83,205	134,770	76,237	26,726	319,195
NMRT10- Military	0	0	0	0	0	0	0	0	292,623	456,705	330,756	82,500	1,162,584
NMRT26- State University	(276,472)	0	0	0	0	0	0	84,795	97,019	159,338	116,682	45,782	227,144
Total Weather Adjustment	(9,251,231)	523,195	2,345,186	(290,487)	(1,719,276)	(54,639)	(1,297,326)	2,267,133	4,671,240	8,863,064	6,036,342	1,811,700	13,904,901

Total EPE Weather Impact (22,876,860)

Amended Filing

EXHIBIT ES-6

EL PASO ELECTRIC COMPANY

2025-2034 DEMAND AND ENERGY FORECAST

Summary

ENERGY (GWH)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	10-YR (7) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		9,684	10,041	10,255	10,467	10,601	10,738	10,871	11,007	11,143	11,285	
Expected:	9,261	9,447	9,790	9,983	10,174	10,286	10,406	10,524	10,646	10,770	10,901	**1.6**
Lower Bound		9,210	9,539	9,711	9,880	9,972	10,074	10,177	10,285	10,397	10,517	
Less: DG (3)		19	54	89	124	159	194	228	263	296	330	
Less: EE (4)		38	76	114	152	190	228	266	304	342	380	
Plus: EV (5)		18	43	79	130	200	297	425	591	791	1,026	
Plus: LL (6)		232	1,626	3,053	4,108	4,559	4,559	4,559	4,571	4,559	4,559	
Native System Energy												
Upper Bound		9,878	11,588	13,279	14,657	15,374	15,639	15,900	16,193	16,485	16,821	
Expected:	**9,261**	**9,640**	**11,329**	**12,912**	**14,135**	**14,696**	**14,839**	**15,013**	**15,241**	**15,481**	**15,774**	**5.5**
Lower Bound		9,403	11,070	12,545	13,613	14,019	14,039	14,127	14,289	14,477	14,728	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,501	2,610	2,675	2,743	2,805	2,862	2,897	2,925	2,967	2,932	
Expected:	2,316	2,369	2,474	2,534	2,596	2,653	2,705	2,736	2,760	2,800	2,762	**1.8**
Lower Bound		2,237	2,338	2,392	2,449	2,501	2,548	2,575	2,595	2,633	2,592	
Less: DG		5	16	18	24	28	34	37	53	61	32	
Less: EE		10	21	31	41	52	62	72	83	93	101	
Plus: EV		2	5	12	19	29	43	61	84	113	193	
Plus: LL		10	200	362	484	533	533	533	533	533	530	
Native System Demand:												
Upper Bound		2,498	2,778	3,007	3,200	3,319	3,385	3,433	3,463	3,520	3,587	
Expected:	**2,316**	**2,366**	**2,642**	**2,859**	**3,035**	**3,135**	**3,185**	**3,222**	**3,242**	**3,292**	**3,353**	**3.8**
Lower Bound		2,234	2,507	2,710	2,869	2,952	2,986	3,010	3,021	3,064	3,119	
Interruptible Load		41	41	41	41	41	41	41	41	41	41	
Upper Bound		2,456	2,735	2,962	3,154	3,273	3,338	3,386	3,416	3,472	3,540	
Expected:	**2,316**	**2,324**	**2,601**	**2,817**	**2,993**	**3,094**	**3,144**	**3,180**	**3,201**	**3,250**	**3,312**	**3.6**
Lower Bound		2,192	2,467	2,672	2,832	2,916	2,950	2,975	2,986	3,029	3,084	

Footnotes:
(1) 2024 are Actual data, Native System Peak occurred on June 16th.
(2) Net Load is forecasted load before the removal of DG and EE.
(3) Impact from Distributed Generation.
(4) Impact from Energy Efficiency.
(5) Impact from Electric Vehicles.
(6) Impact from Large Load Customers.
(7) 10-Year Compounded Average Growth Rate.

Exhibit ES-6
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Amended Filing

EXHIBIT ES-6

EL PASO ELECTRIC COMPANY

2035-2044 DEMAND AND ENERGY FORECAST

Summary

ENERGY (GWH)	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	20-YR (1) CAGR
Native System Forecast (NFL)											
Upper Bound	11,435	11,589	11,743	11,898	12,058	12,223	12,388	12,561	12,738	12,920	
Expected:	11,040	11,184	11,328	11,474	11,624	11,780	11,936	12,099	12,267	12,440	**1.5**
Lower Bound	10,645	10,779	10,913	11,050	11,190	11,337	11,484	11,637	11,796	11,959	
Less: DG (3)	364	399	431	464	498	531	563	596	628	662	
Less: EE (4)	418	456	494	532	532	532	532	532	532	532	
Plus: EV (5)	1,281	1,547	1,792	2,016	2,208	2,374	2,494	2,596	2,676	2,746	
Plus: LL (6)	4,559	4,571	4,559	4,559	4,559	4,571	4,559	4,559	4,559	4,571	
Native System Energy:											
Upper Bound	17,181	17,564	17,900	18,227	18,561	18,885	19,138	19,388	19,620	19,856	
Expected:	**16,097**	**16,447**	**16,752**	**17,052**	**17,361**	**17,661**	**17,893**	**18,125**	**18,341**	**18,563**	**3.5**
Lower Bound	15,013	15,330	15,604	15,876	16,160	16,438	16,649	16,862	17,062	17,270	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,967	2,997	3,041	3,079	3,118	3,150	3,198	3,240	3,283	3,319	
Expected:	2,797	2,826	2,870	2,907	2,945	2,977	3,024	3,066	3,108	3,143	**1.5**
Lower Bound	2,627	2,655	2,699	2,735	2,773	2,804	2,851	2,891	2,933	2,967	
Less: DG	31	38	35	41	51	45	43	49	51	67	
Less: EE	111	121	131	141	141	141	141	141	141	141	
Plus: EV	239	284	327	363	394	418	437	451	461	468	
Plus: LL	530	530	530	530	530	530	530	530	530	530	
Native System Demand:											
Upper Bound	3,664	3,726	3,810	3,872	3,935	4,000	4,071	4,124	4,178	4,206	
Expected:	**3,425**	**3,482**	**3,562**	**3,619**	**3,678**	**3,740**	**3,807**	**3,857**	**3,908**	**3,934**	**2.7**
Lower Bound	3,186	3,238	3,313	3,366	3,421	3,480	3,544	3,590	3,639	3,662	
Interruptible Load:	41	41	41	41	41	41	41	41	41	41	
Upper Bound	3,617	3,678	3,762	3,824	3,887	3,952	4,023	4,076	4,130	4,159	
Expected:	**3,384**	**3,441**	**3,520**	**3,577**	**3,637**	**3,699**	**3,766**	**3,816**	**3,867**	**3,893**	**2.6**
Lower Bound	3,151	3,203	3,278	3,331	3,386	3,445	3,509	3,555	3,604	3,627	

Footnotes:
(1) 20-Year Compounded Average Growth Rate.

Exhibit ES-6
Page 2 of 2

Amended Filing

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 317	)))))	**Case No. 25-00082-UT**

DECLARATION OF ENEDINA SOTO IN SUPPORT OF THE FOREGOING AMENDED FILING DIRECT TESTIMONY

I, ***Enedina Soto***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as the *Manager of Load Research and Data Analytics.*

3. I have reviewed the foregoing Amended Filing Direct Testimony of Enedina Soto, and the exhibits, schedules, and workpapers sponsored by me and I confirm, to the best of my knowledge, that those materials are complete, accurate, internally consistent, and consistent with the Amended Application.

4. The foregoing Amended Filing Direct Testimony of Enedina Soto, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

5. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Amended Application for Revisions of Its Retail Electric Rates Pursuant to Advice Notice No. 317.***

Amended Filing

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 6, 2026.

/s/ Enedina Soto
ENEDINA SOTO