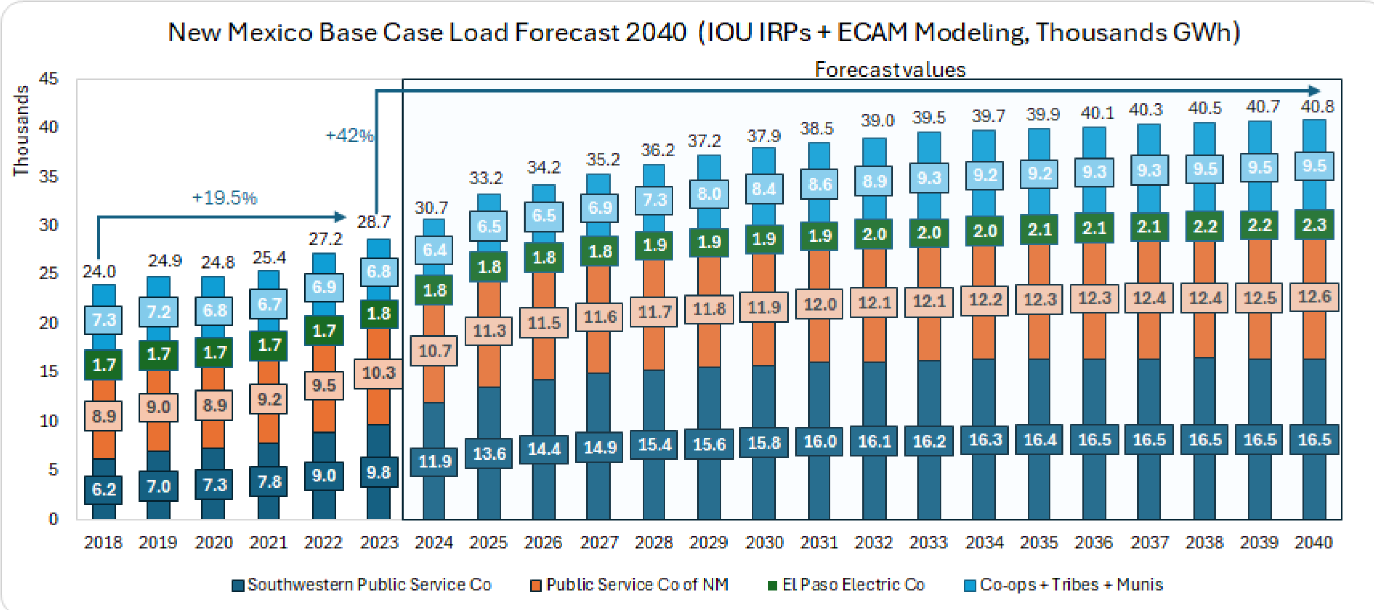
ECAM Energy Grid Update: Executive Summary



- **Reliance on the state's electricity grid is rapidly increasing** due to the electrification of transportation, buildings, and industry, and as New Mexico shifts its electricity generation portfolio from firm and dispatchable conventional resources to intermittent renewables.

- This transition presents tradeoffs that force stakeholders to balance the principal objectives that govern the transition and operation of New Mexico's electricity grid: reliability, affordability, and sustainability.

- **Grid modernization is a means of achieving efficiencies in the energy system to balance these principal objectives by *making better use of existing infrastructure*.**

  - Efficiencies achieved by modernizing the grid result in least-cost optimal solutions for utility asset portfolios and new markets for distributed resource participation that benefit ratepayer affordability by deferring upgrades and minimizing peak capacity procurement while compensating peak-shaving behavior.

  - New technologies deployed on the grid also provide operators with greater visibility into real time distribution and transmission system conditions, benefiting service reliability and fire prevention efforts while providing cost-effective resource adequacy via improved demand response capabilities.

  - Grid modernization solutions that reduce peak demand serve New Mexico's long term decarbonization goals by reducing utility needs to procure power from gas-fired peaker plants, while incentivizing distributed energy resources, demand response, and energy efficiency.

- **Necessary system buildouts and traditional upgrades currently lag** behind accelerating demand, and worsening supply chain constraints for key components continue to exacerbate already elongated project durations.

- As a result, **the grid is becoming a bottleneck for statewide economic development and other priorities**. For example, nearly a third of new businesses interested in relocating to New Mexico ultimately pass up on the state citing an inability to secure a prompt grid connection.

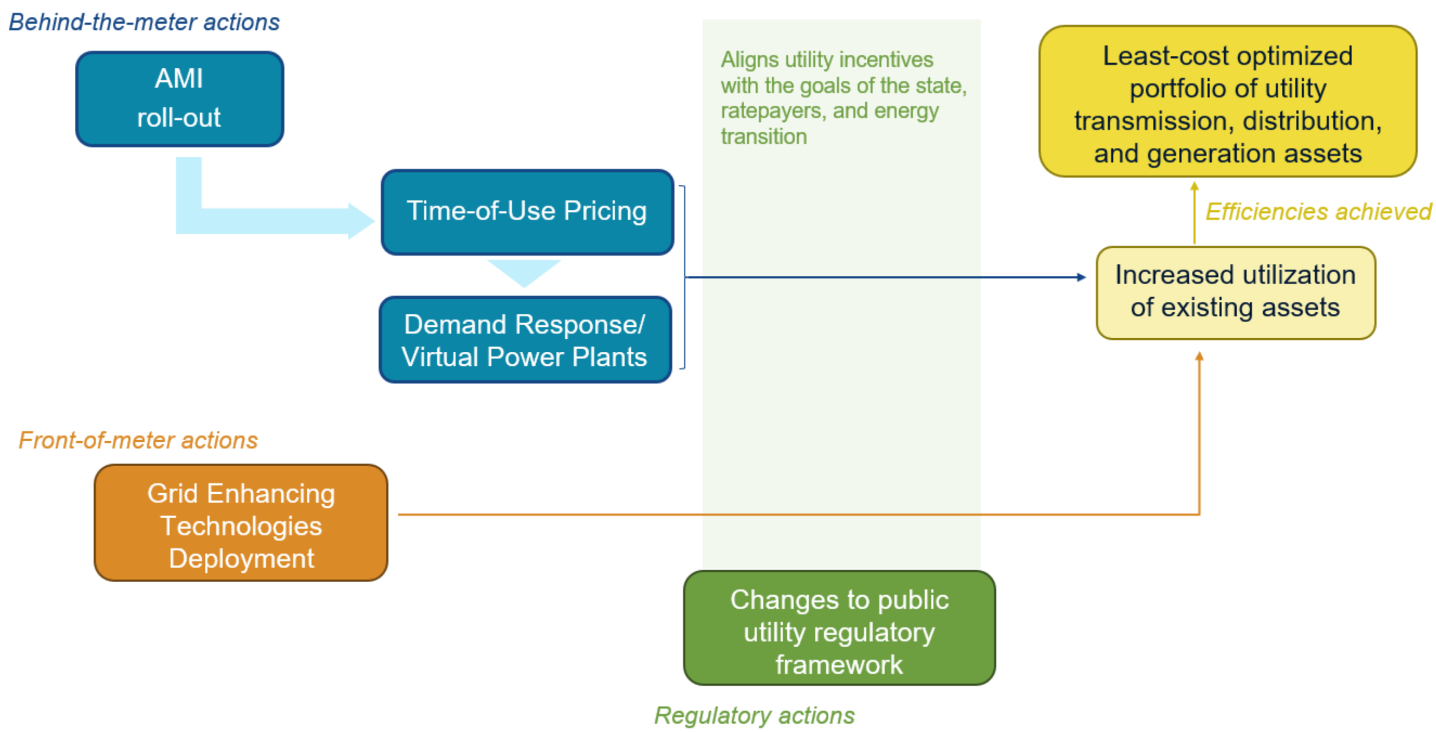
- Enhanced demand management and increased asset utilization enabled by **grid modernization technologies can help to bridge the current infrastructure gap** while traditional upgrades and expansions continue in the background, **ensuring that New Mexico continues to progress in the energy transition without sacrificing economic development opportunities and other priorities.**

- The following paper provides detailed updates on key areas of concern regarding New Mexico's electricity grid. It also provides a menu of evidence-based policy recommendations and relevant examples from other jurisdictions as a suggested policy roadmap for legislators, regulators, and industry stakeholders in New Mexico.

- In broad strokes:

    - New Mexico should build on recent smart meter deployments at local utilities to cultivate new markets in demand response and aggregated distributed resources.
    - The state's transmission grid operators should deploy grid-enhancing technologies and utility-scale storage to expand existing capacity and expedite resource interconnection.
    - Finally, regulators and industry stakeholders should reexamine current utility incentive structures and design a regulatory framework that is better aligned with the goals of the energy transition.

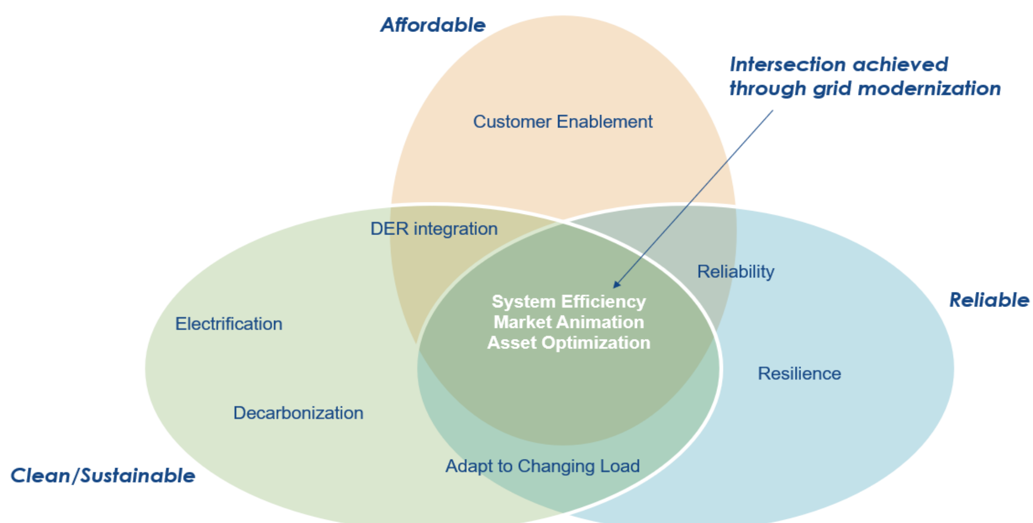
ECAM Vision for the Next Steps in Grid Modernization



Section 1: Introduction

In its 2021 Electric Grid Baseline Report[1], the Energy Conservation and Management Division (ECAM) outlined ten key objectives to guide energy infrastructure policy and planning in New Mexico, as mandated by the Energy Grid Modernization Roadmap Act of 2020[2]. Since then, the trajectory of the state's energy transition has changed significantly amid new emissions reduction initiatives, a surge in federal investments, tax policy changes, and evolving market dynamics. This new and rapidly changing energy landscape calls for an updated evaluation of New Mexico's electricity grid. This update will first distill the primary goals of the state's energy transition and demonstrate how grid modernization efforts can support these objectives. Subsequent sections will provide a current analysis of the grid in relation to the previously defined goals. Finally, this report will offer recommendations to better frame future energy infrastructure planning in New Mexico.

The ten objectives covered in the 2021 Baseline Report can be sorted into three principal components (reliable, affordable, clean) which this report will refer to as the "energy transition goals" (Figure 1). While these goals are essential to state climate policy objectives, they often appear to involve tradeoffs. For example, New Mexico's push to decarbonize has led to more electrification and the replacement of firm, conventional capacity with variable renewable resources. This shift raises concerns about resource adequacy and power system reliability. Moreover, as households adopt distributed energy resources (DERs) like rooftop solar and electric vehicles, daily electricity demand becomes less predictable and upgrades to the distribution system could be required to host increasing amounts of DERs. These improvements require significant investment and changes to rate structures that raise affordability concerns in a state with high levels of poverty and low incomes[3]. Grid modernization is one means of achieving efficiencies in the energy system that synchronize the objectives of the energy transition (Figure 1).



[1] Waite and Zigich. (2021). ECAM. "[Baseline of New Mexico's Electric Grid]"
[2] NM Stat § 71-11-1 (2023)
[3] New Mexico Legislative Finance Committee. "Despite Benefits, Poverty Persists". December 2023.

Figure 1

Grid modernization can be thought of as an iterative process that transforms existing grid architecture and operation to accommodate flexibility in energy generation, distribution, and management. The US Department of Energy's (DOE's) 2015 Grid Modernization Multi-Year Program Plan defined grid modernization as:

> "a process, not an end-point. It is a transformation from a monolithic grid to one that is modular and agile: from centralized generation characterized by decisions driven by affordability and reliability, to one of both centralized and distributed generation and intelligent load control characterized by decisions driven by cost and environmental sustainability, contained events, personalized energy options, and security from all threats."[4]

The DOE subsequently provided helpful context for this definition in citing operational efficiency as a motivating concept behind grid modernization[5] and arguing that the deployment of innovative grid technologies facilitates grid operators' maximization of capital efficiency while serving multiple goals with the same investment[6]. The diagram below illustrates how strategic grid modernization on both sides of the meter can lead to efficiencies in the power system that achieve the stated objectives of the energy transition.

ECAM Vision for the Next Steps in Grid Modernization

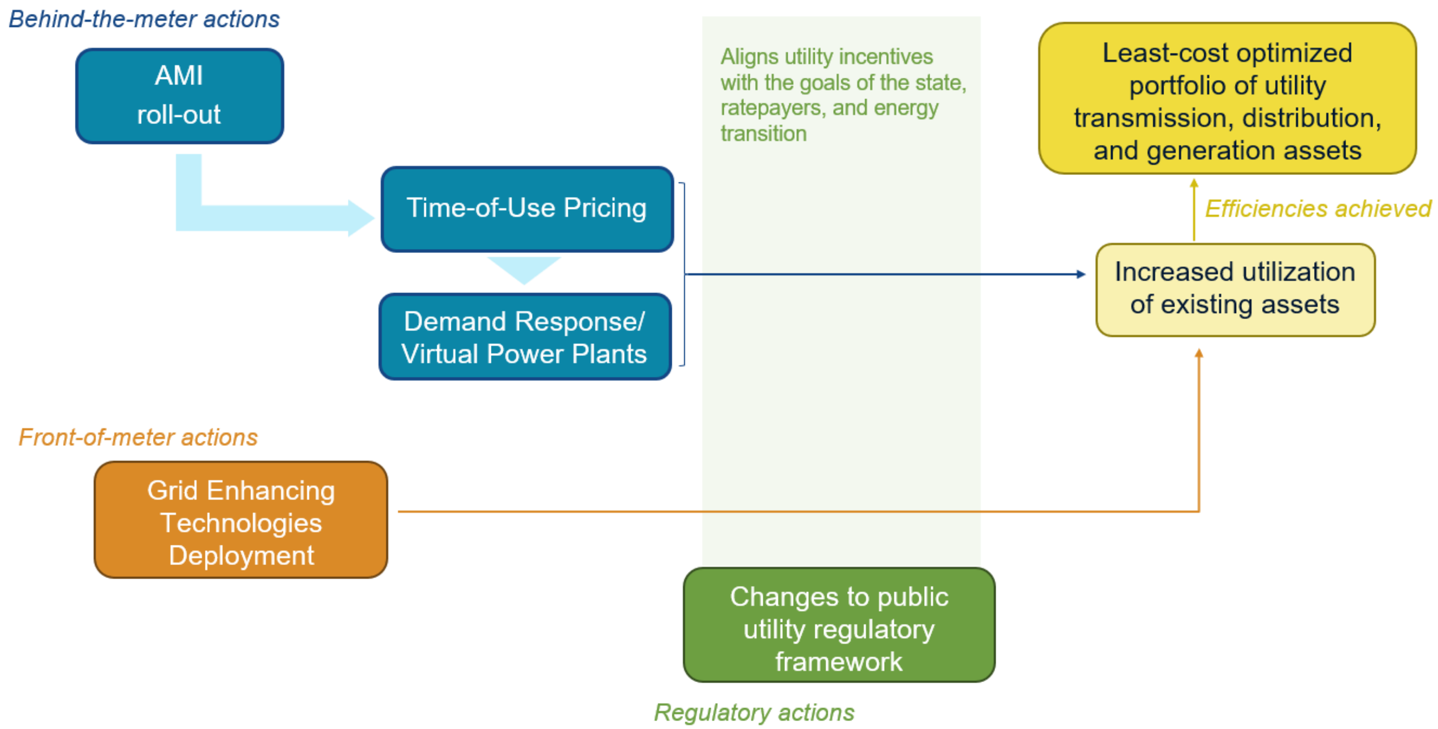


Figure 2

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[4] GMI Resources | Department of Energy
[5] De Martini & Shwartz. (April 2024). U.S. Department of Energy. "Distribution System Evolution".
[6] White et. al. (April 2024). U.S. Department of Energy Loan Programs Office. "Pathways to Commercial Liftoff: Innovative Grid Deployment".

As shown above, grid modernization technologies can be deployed to optimize utility asset portfolios and stimulate market activity, driving overall system efficiency. Asset optimization minimizes total system costs by refining the scope of necessary upgrades or grid expansion a utility undertakes to meet its obligations. Total system costs are also minimized due to reduced maintenance and operations spending achieved through enhanced reliability. Market animation achieves efficiency at the retail level by introducing competition into the vertically integrated and traditionally monopolistic distribution system. In a modernized grid, new markets compensate aggregated DERs for providing grid services normally limited to utility-scale resources.

The overall result of grid modernization is more effective and efficient use of existing public utility assets - the distribution grid, transmission grid, and bulk power generation - thus advancing the energy transition goals while minimizing investments in new and expensive infrastructure. Additionally, by reducing household energy costs and offering near-term, cost-effective solutions to transmission and distribution congestion, grid modernization can help align New Mexico's energy transition goals with broader economic development and social welfare objectives.

I. Changing Demand and Resource Mix

Anticipated load growth underscores the urgency to upgrade New Mexico's power grid, preventing it from becoming a bottleneck to economic development and decarbonization efforts and, instead, leveraging it to support the state's goals and ambitions. Load forecasts are the main input guiding grid planning and investment because the magnitude and timing of electricity demand ultimately determines how much capacity utilities procure. ECAM's 2021 baseline report expected that efforts to decarbonize New Mexico's economy would accelerate transportation, building, and industrial electrification in the state, yet utility integrated resource plans (IRPs) at the time contemplated only modest future load growth. However, the most recent utility IRPs from 2023 include substantial upward revisions to load forecasts, adding over 100 terawatt hours to expected demand by 2040 vs. prior estimates between PNM and SPS[7] (Figure 3). ECAM now projects that statewide annual electricity demand will grow +42% by 2040 (Figure 4).

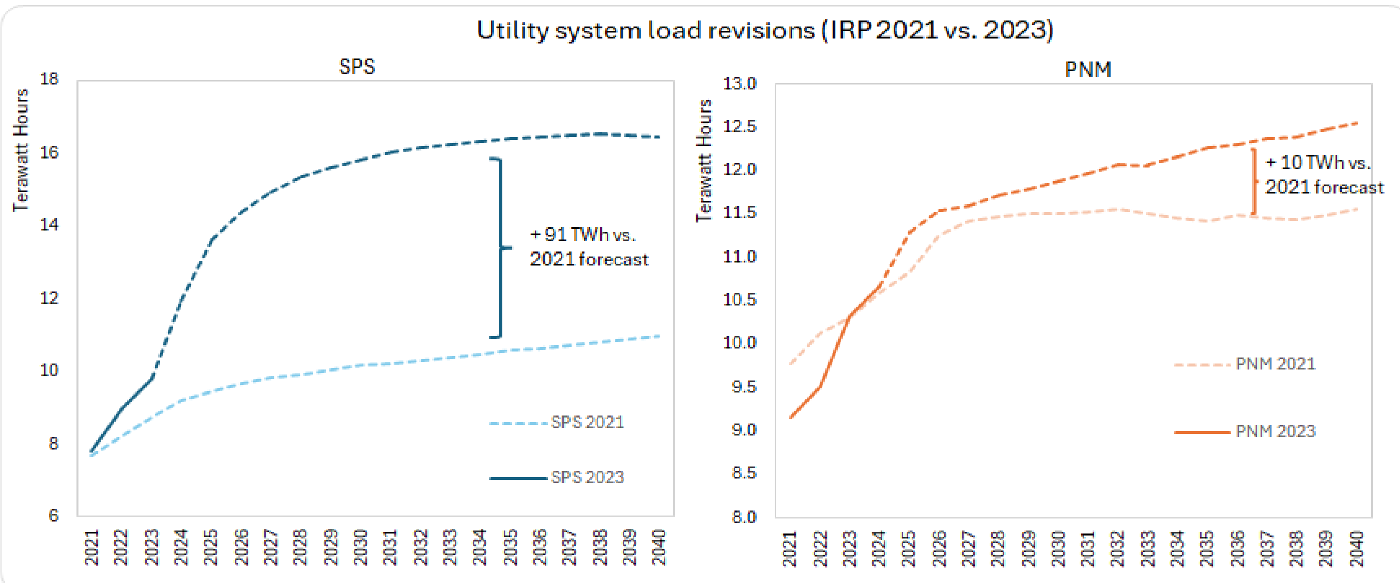


Figure 3

[7] EPE is scheduled to file a new IRP in 2026 and is absent from the above analysis.

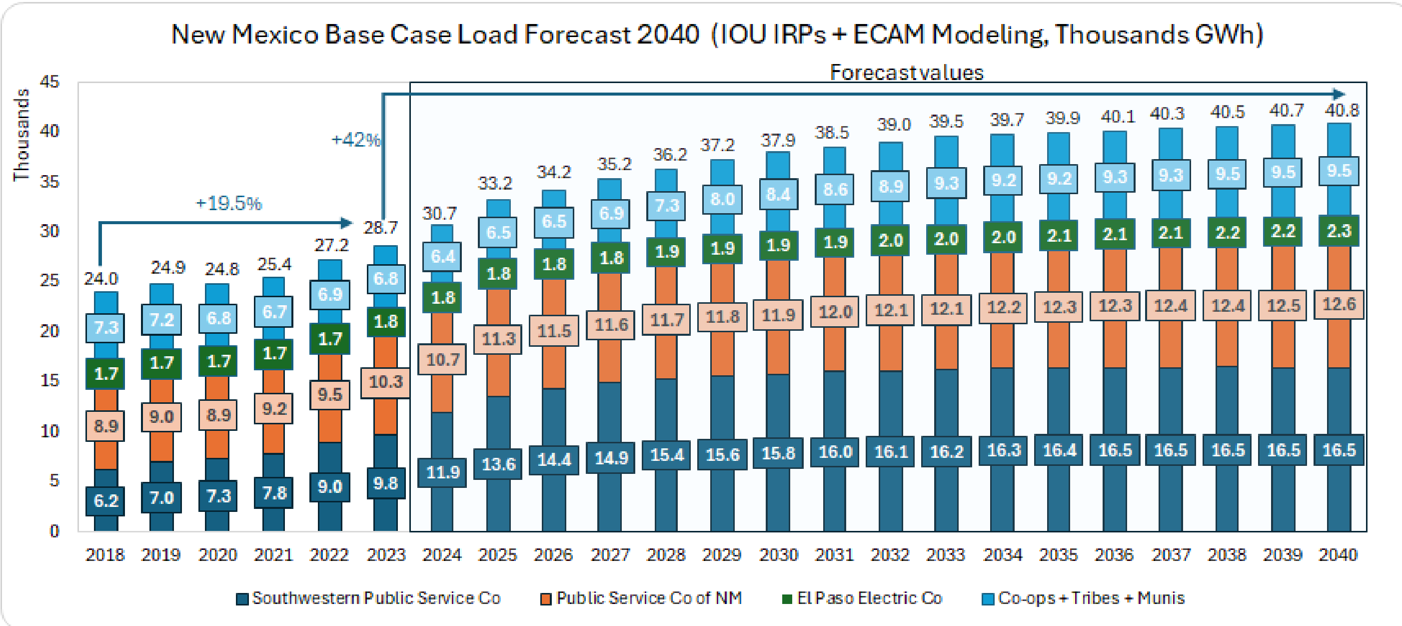


Figure 4

a. Industrial Demand Growth

Annual retail electric sales in the state have grown +24% since 2015 driven largely by the industrial segment, which grew +59% in the last 10 years (Figure 5). Increasing load in this segment can be traced back to the electrification of oil and gas operations in the Permian Basin and the growth of data centers clustered in the Albuquerque metropolitan area (and becoming more common across the state)[8].

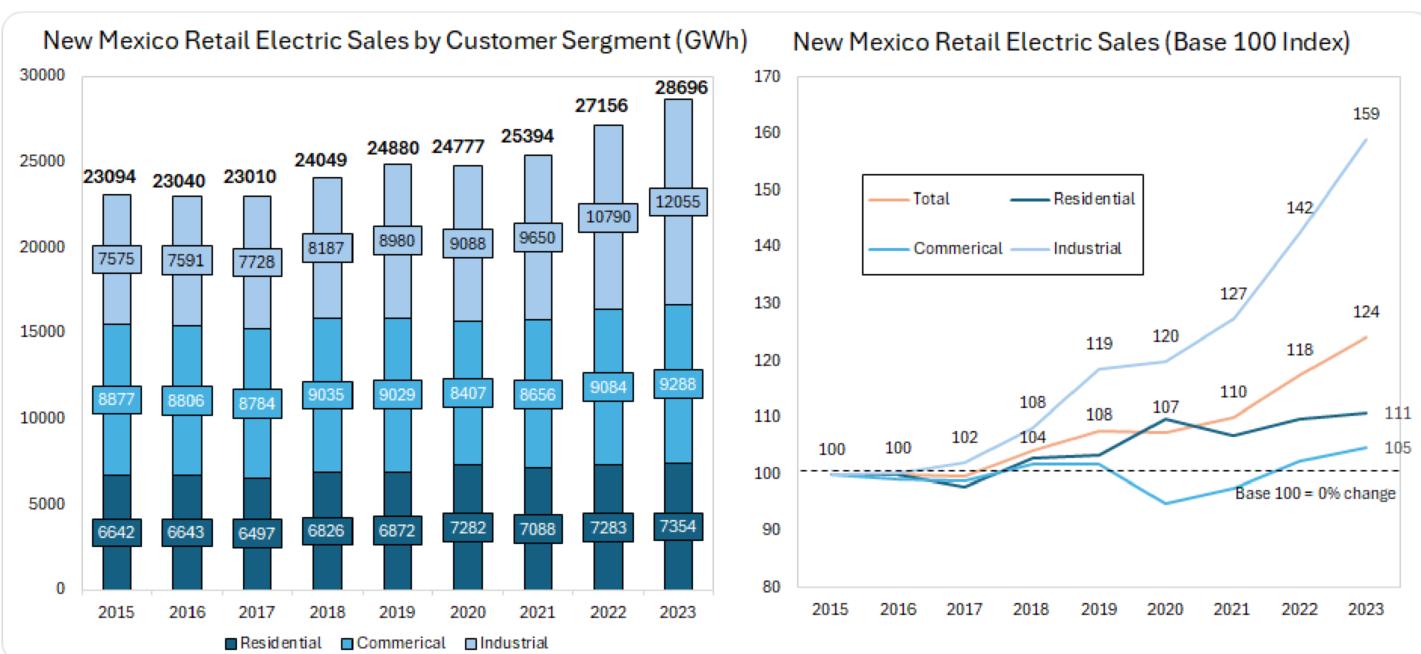
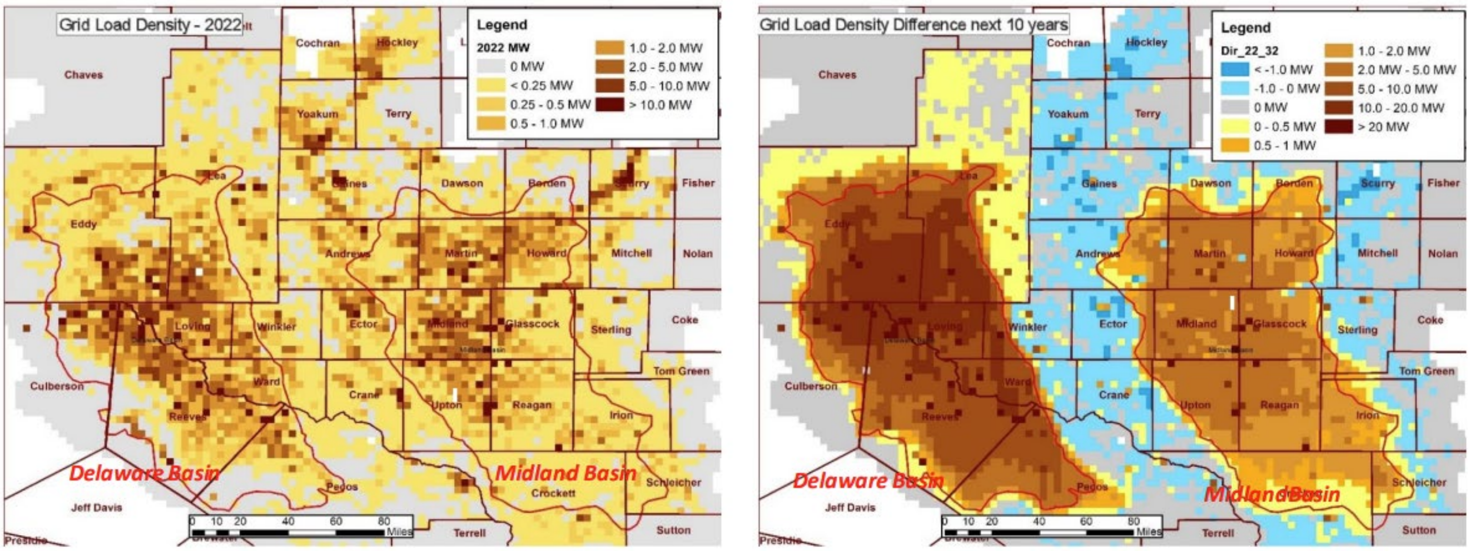


Figure 5

[8] See New Mexico Data Center Map for geographic distribution

Corporate emissions reduction goals driving the electrification of oil and gas operations in New Mexico are the main contributor to the upward revision in SPS' IRP load forecast for 2042. In 2022, average installed monthly load in New Mexico's portion of the Delaware Basin (a subsection of the Permian Basin) was 816 MW[9]. S&P Global Commodity insights projects this to grow to 3,100 MW by the end of the 2030s to meet industry grid connection targets[10]. Figure 6 shows the expected change in installed electric load distributed across the Permian Basin from 2022 to 2032. Peak oil production in the Permian Basin will require over 17 GW of installed electric drilling capacity by the late 2030s[11].



Current (2022) load demand distribution

Next 10 years incremental changes – Projected Load Demand Forecast

Figure 6 (Source: S&P Global Commodities Insights)

b. Transportation and Building Electrification

New Mexico's Advanced Clean Car and Clean Truck Rules[12], implemented in late 2023, require a percentage[13] of annual new light-duty vehicle shipments to local dealerships to be zero-emission. The 2024 NM legislature also passed the "Clean Car Income Tax Credit" which provides incentives of up to $3,000 for the purchase of a clean fuel vehicle and up to $25,000 for commercial DCFC[14] chargers[15]. Combined with new federal EV tax incentives[16], these changes are expected to be additional drivers of residential and commercial load growth in the state.

Leveraging data from the New Mexico Motor Vehicle Department and the Federal Highway Administration, ECAM expects light-duty EV registrations to grow from 34,000 in 2023 to over 900,000 in 2040, representing slightly less than

[9] S&P Global Commodity Insights. (2023). Electrifying the Permian Basin. ERCOT Planning Committee Presentation.
[10] Ibid.
[11] Ibid.
[12] Official Clean Cars and Clean Trucks Rule, 20-2-91 NMAC
[13] The mandated ZEV share of vehicle shipments increases from 43% for model year 2027 to 82% for model year 2032. See more detailed information here from the New Mexico Environment Department.
[14] Direct Current, Fast Charging
[15] EMNRD Clean Cars Tax Credit. 2024-29
[16] IRS Publication 5866, New Clean Vehicle Tax Credit Checklist. 2023

half of New Mexico's light-duty vehicle stock forecast (Figure 7). Average daily vehicle charging load is slated to grow from 300 MWh in 2023 to 8.5 GWh by 2040 (Figure 7), after modeling for vehicle miles traveled and usage at different points of grid connection.

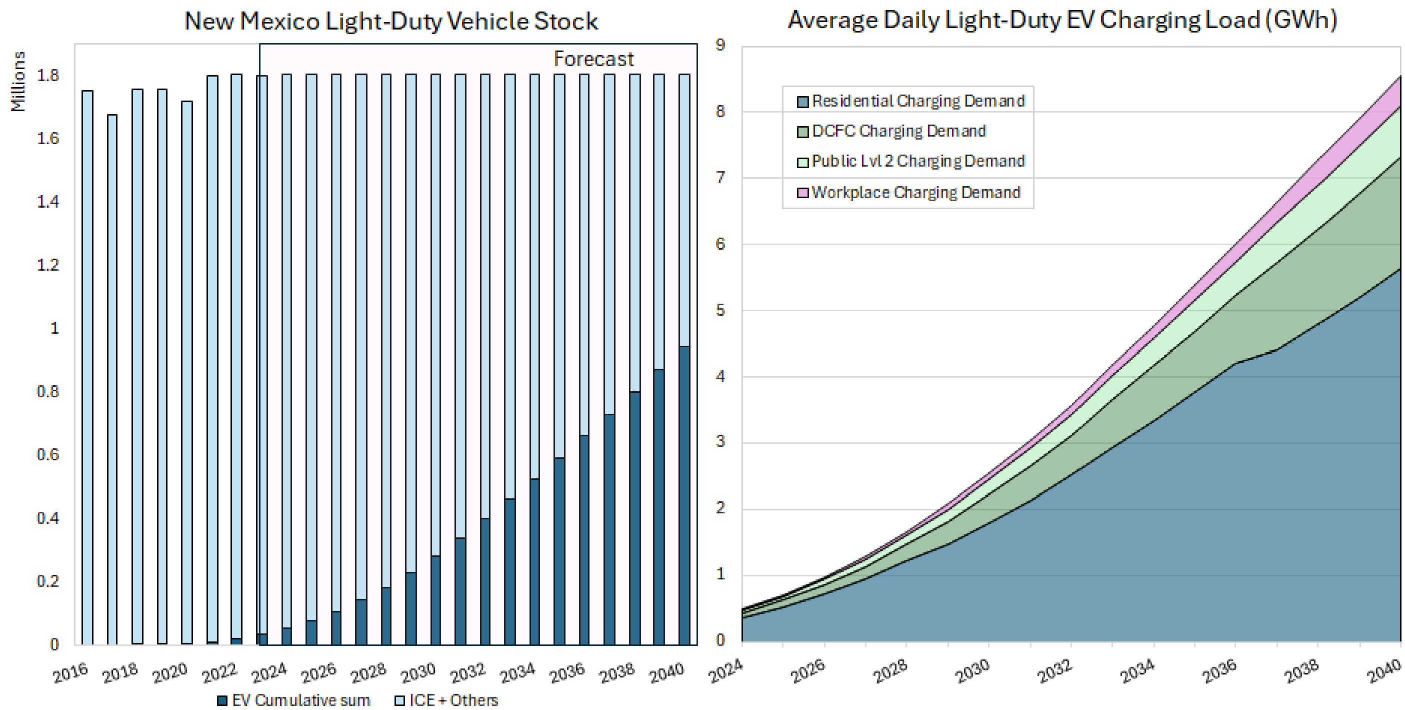


Figure 7

Compounding added load from electric vehicle charging, federal and state governments have ramped up efforts to encourage the electrification of residential heating systems and home appliances as part of broader building decarbonization efforts. The 2022 Federal Inflation Reduction Act (IRA), for example, includes incentives and funding programs designed to accelerate building electrification in the United States. The Energy Efficiency Home Improvement Tax Credit allows taxpayers to deduct 30% of the cost of an electric heat pump purchase up to $2,000[17]. The IRA also appropriated $8.8 billion dollars to fund the federal Home Electrification and Appliance Rebates (HEAR) and Home Energy Rebate (HER) programs[18] which reimburse low-income households for electrification purchases such as heat pumps and induction ranges.

As the market for home heating, cooling, and appliances transforms to support a future of widespread whole-home electrification, statewide residential load in New Mexico is slated to grow substantially. Simulated demand profiles from NREL's ResStock project suggest building electrification efforts in New Mexico could increase annual residential load by 9% to 52% depending on the type of appliances installed and whether they are paired with other efficiency measures

[17] 26 U.S. Code § 25C
[18] IRA sections 50121 and 50122

such as weatherization and insulation improvements (Figure 8). These figures do not capture the impact of commercial heating fuel switching to electricity which is expected to further amplify load growth.

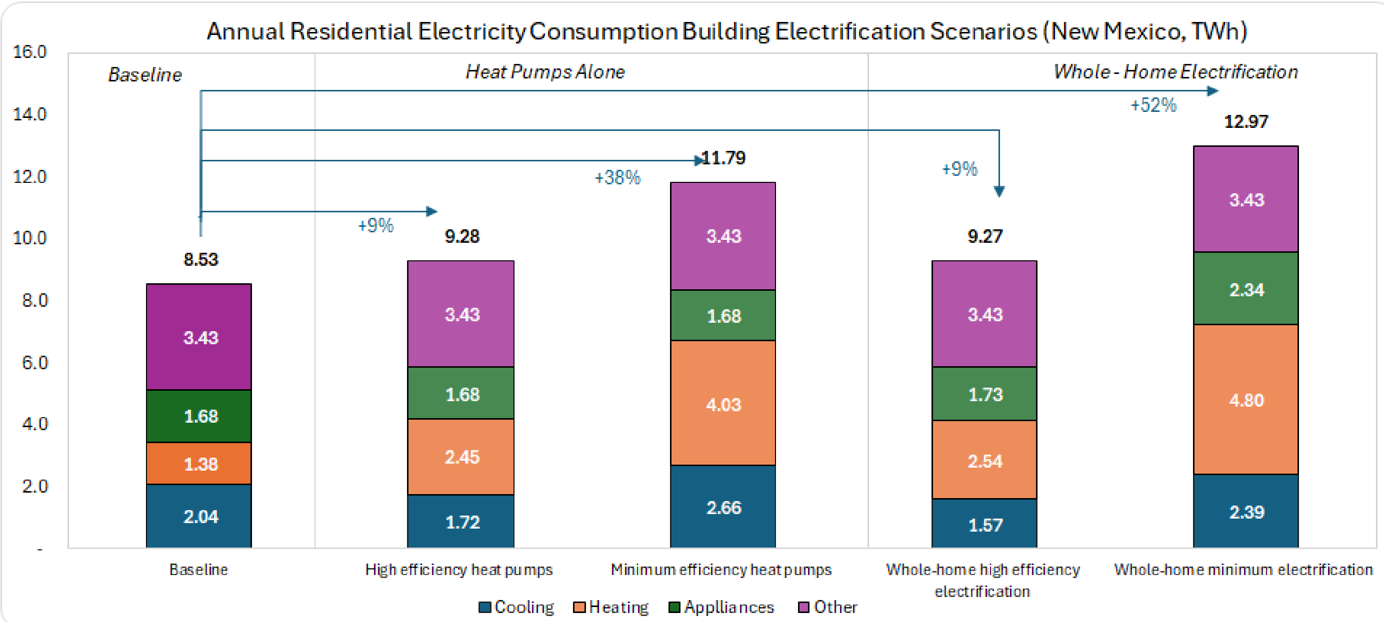


Figure 8

c. Changing load shape

In addition to an anticipated increase in the magnitude of demand, increasing amounts of renewables added New Mexico's generation portfolio in recent years have altered daily net load shapes within the state's balancing authorities, with an increasingly deeper trough in the daily net load curve. As more solar comes onto the grid, more dispatchable resources[19] will have to be deployed in tandem to meet load during the evening ramp. Conventional resources that provide frequency response services to maintain grid are also increasingly taken offline during midday, resulting in less grid stability[20]. Figure 9 illustrates the effect of increased renewables on the net load[21] that must be balanced with dispatchable resources on an average March weekday in PNM's balancing authority. In 2021, March net load grew +19% between six and eight on an average weeknight. By 2024, that same ramp was +180% on average.

[19] Dispatchable resources can generate on demand and are most commonly natural gas peaker plants
[20] Denholm et. al. (2015). "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart". National Renewable Energy Laboratory. Pg. 13.
[21] Total system demand minus total renewable generation per hour

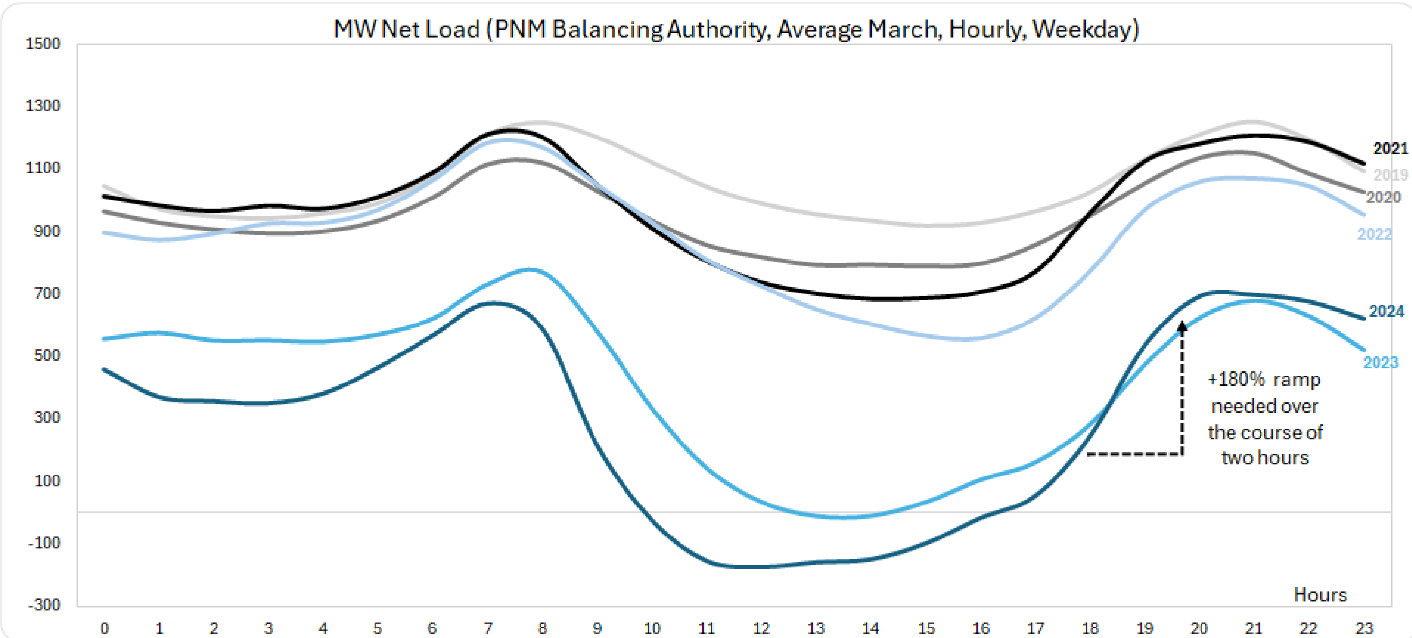
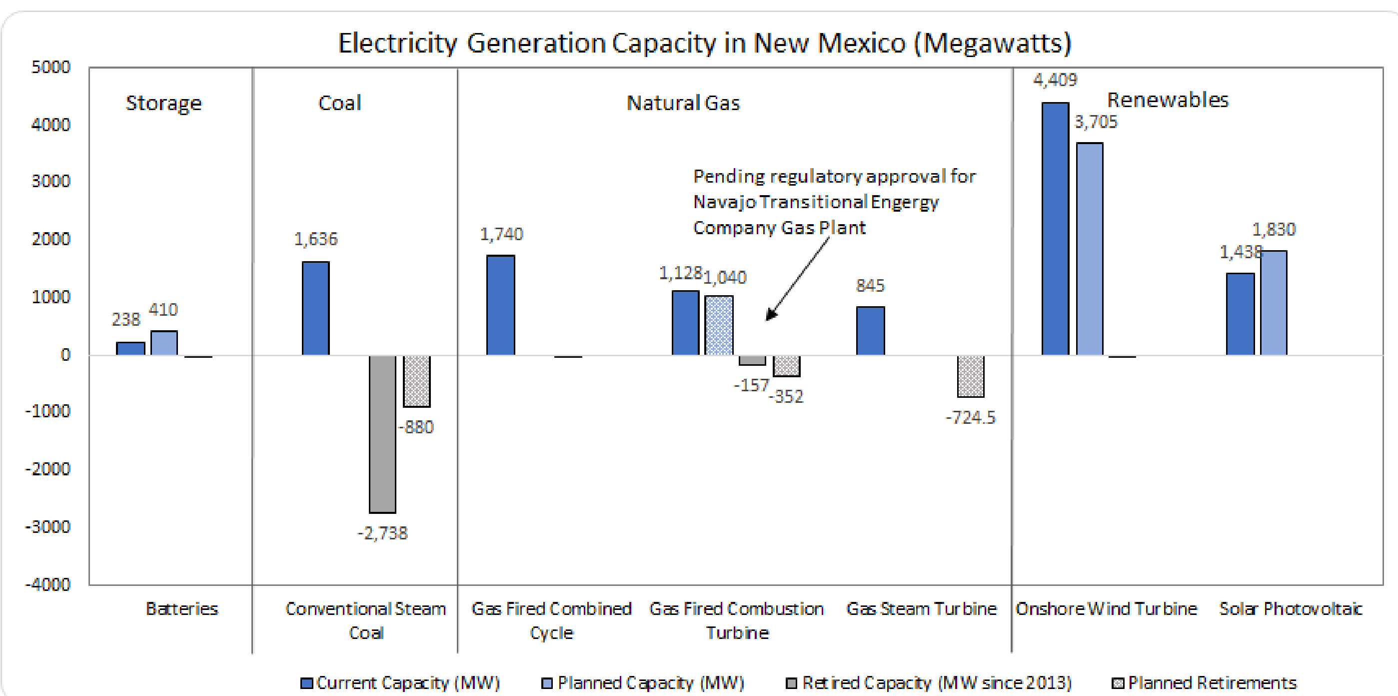


Figure 9

Statewide net solar generation has grown +66% year over year and +508% since 2016[22]. As a result, grid operators have become more reliant on fast-ramping peak-serving resources such as natural gas and battery storage to meet evening load. Current planned capacity adds in New Mexico will double the nearly 6,000 MW of wind and solar already installed (Figure 10).



[22] National Renewable Energy Laboratory. (2014). Form EIA-906, EIA-920, and EIA-923 Databases [data set]. Retrieved from https://data.openei.org/submissions/265.

Figure 10

While utility-scale solar growth is the main driver of changing load shape and peak timing, distributed solar installed capacity in New Mexico is forecast to grow +274% over the next decade to 1160 MW (Figure 11). The intermittency and unpredictability of increasing amounts of distributed solar adds to the challenge that grid operators face by inserting more uncertainty at localized levels that may cause instability due to frequency changes, voltage variation, and reverse power flow[23].

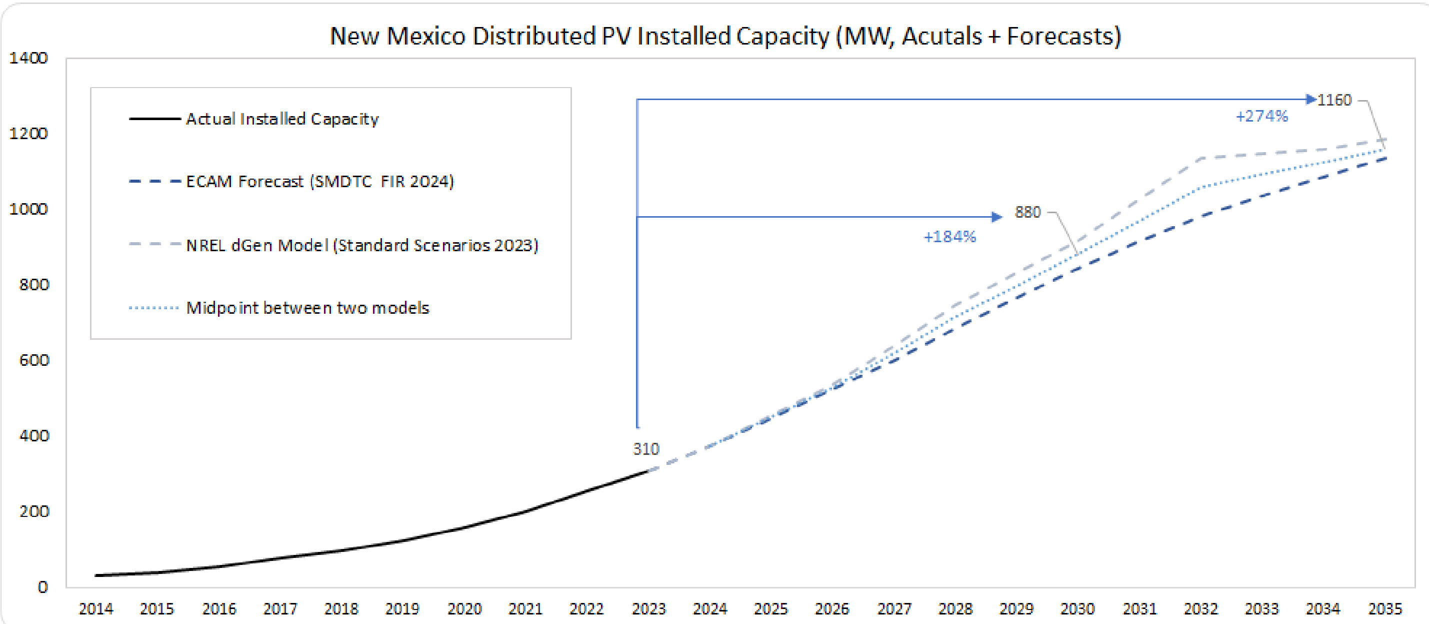


Figure 11

II. Grid Reliability in New Mexico

Reliability is an important factor influencing energy grid planning and investment in New Mexico as more renewables are deployed and electricity demand increases. The Federal Energy Regulatory Commission (FERC) defines grid reliability as:

> "the provision of an adequate, secure, and stable flow of electricity as consumers may need it. In other words, when you flip the light switch, the lights turn on**.** The grid remains functional even during unanticipated but common system disturbances, such as loss of a source of energy generation from an energy provider or failure of some other system element.[24]"

At its root, grid reliability implies minimizing the frequency and duration of outages. "Operational reliability" and "resource adequacy" are two aspects of reliability that affect different parts of the bulk power system. Operational

[23] Majeed, Issah & Nwulu, Nnamdi. (2022). Impact of Reverse Power Flow on Distributed Transformers in a Solar-Photovoltaic-Integrated Low-Voltage Network. Energies. 15. 9238. 10.3390/en15239238.
[24] Federal Energy Regulatory Commission. (2023). Reliability Explainer.

reliability refers to the power system's ability to withstand sudden disturbances such as a downed tree on a powerline that causes an electric short circuit fault on the distribution grid[25]. Resource adequacy is the ability of the power system to meet electricity load with procured supply-side and demand-side resources[26].

a. Operational reliability

The EIA evaluates operational reliability using a set of grid performance metrics that track the duration and frequency of outages. A system's average yearly frequency of outages (SAIFI) is combined with the average yearly duration of outage minutes (SAIDI) to arrive at CAIDI (the customer average interruption duration index) which provides the average amount of minutes per duration a customer faces per outage event. This datapoint provides insight into how expedient a utility is in restoring power.

New Mexico's investor-owned utilities (IOUs) broadly track the average for U.S. electricity distribution providers while the state's cooperatives experience more variation given their service territories are more rural and, as a result, more difficult to maintain (Figure 12). In 2023, a given customer at a New Mexico IOU experienced 0.8 outage events, 38% less frequent than a given US customer faced, while outages were 50% more frequent at statewide coops (Figure 12)[27].

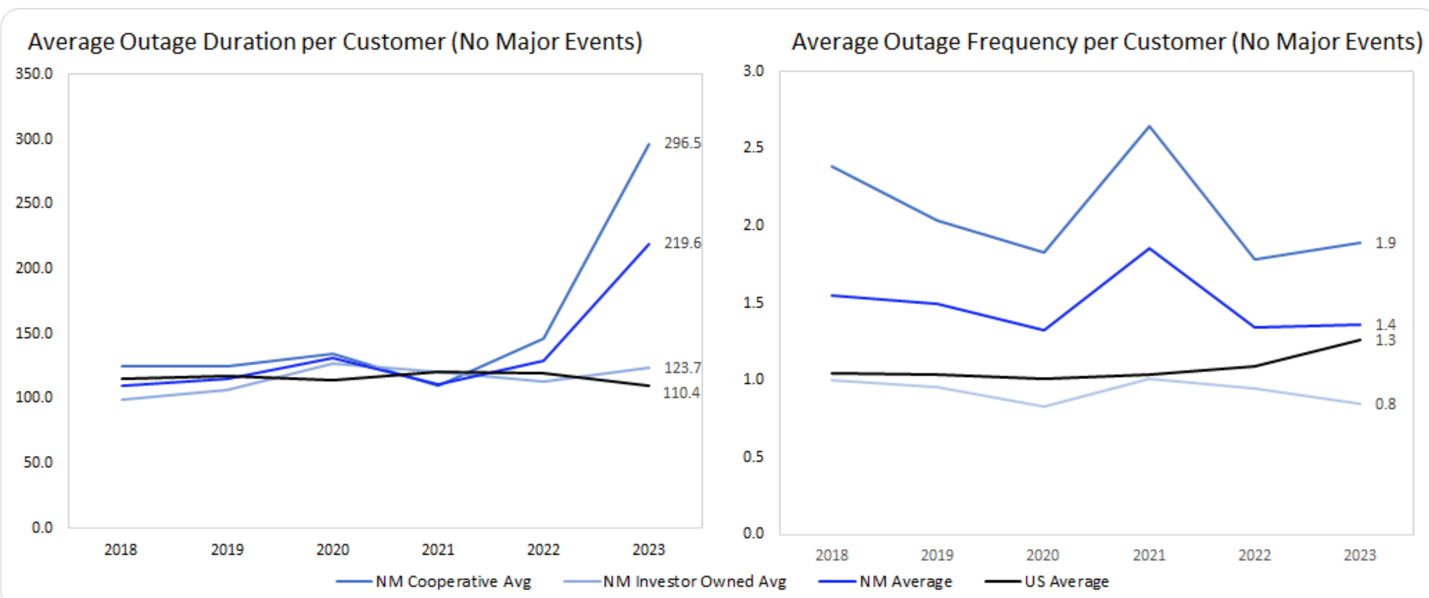


Figure 12

Utility-specific data reported to the Department of Energy from New Mexico's largest IOUs reveals the average customer has experienced increasingly longer outages on average since 2018. This can likely be attributed to more severe

[25] Ibid.

[26] Ibid.

[27] It should be noted that some electric cooperatives in New Mexico do not adhere to IEEE standards when reporting reliability statistics and as a result are not included in these calculations

weather events that require more involved power restoration services (Figure 13). The frequency of outages has declined slightly since 2018 at both PNM and SPS, although discernable trends in both outage duration and frequency are less apparent when accounting for major event days (MED)[28] (Figure 13 and Figure 14).

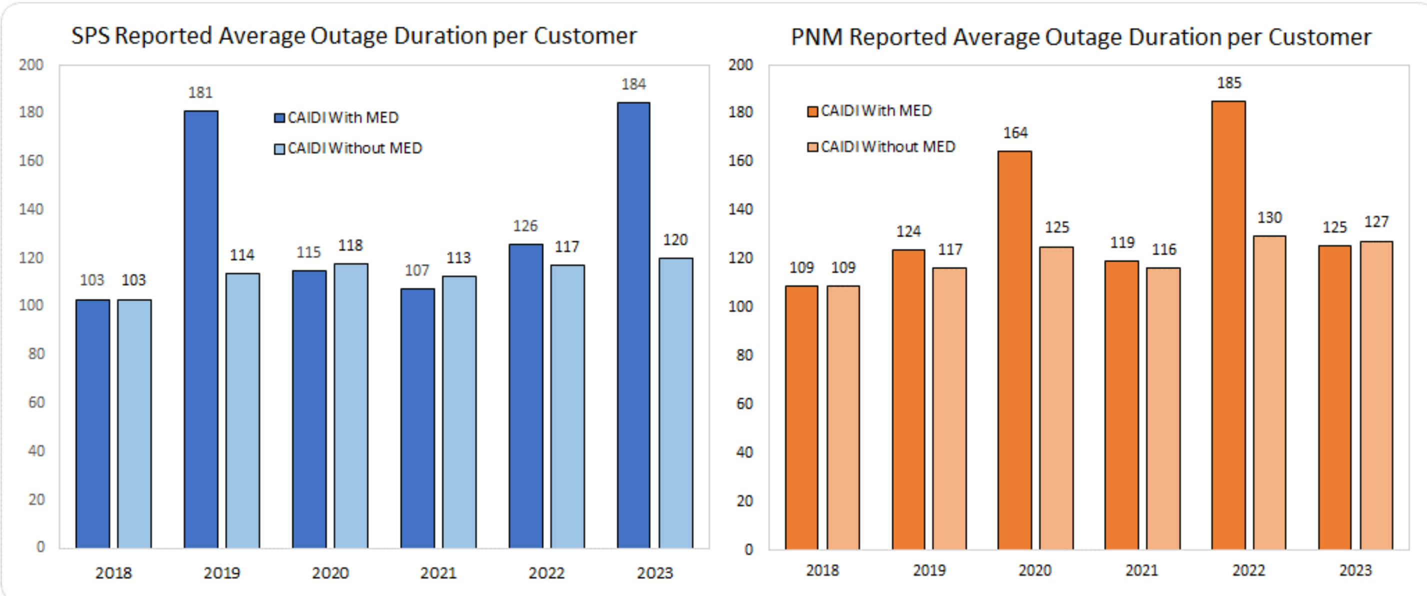


Figure 13

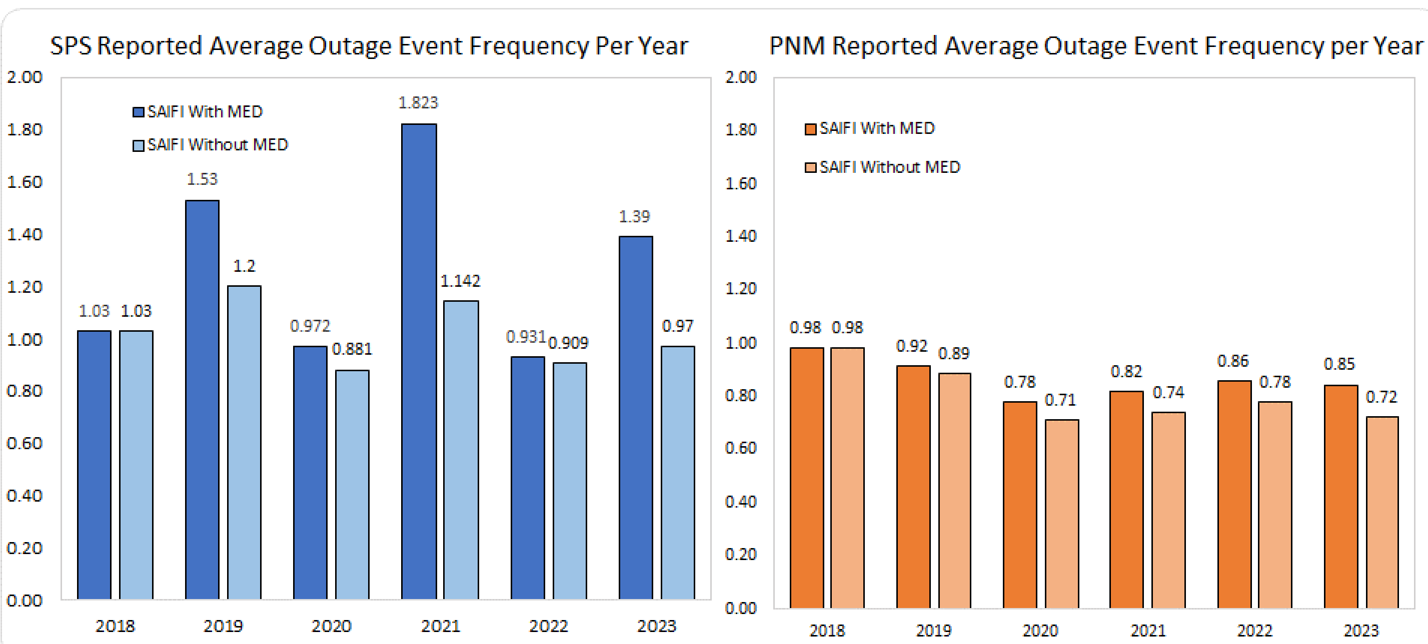


Figure 14

[28] A major event day defined by the IEEE Standard indicates a day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a pre-determined threshold value.

In 2024, the New Mexico Public Regulation Commission (PRC) developed and approved a new rule standardizing reliability metrics reporting to better assess the overall performance of IOUs with respect to operational reliability [29]. The required annual filings will be used by the commission and IOUs to monitor the alignment between reliability trends and utility investments. This report will reveal which feeders are performing the worst year-over-year and can be used to determine where grid enhancements might offer the most benefit.

b. Resource Adequacy

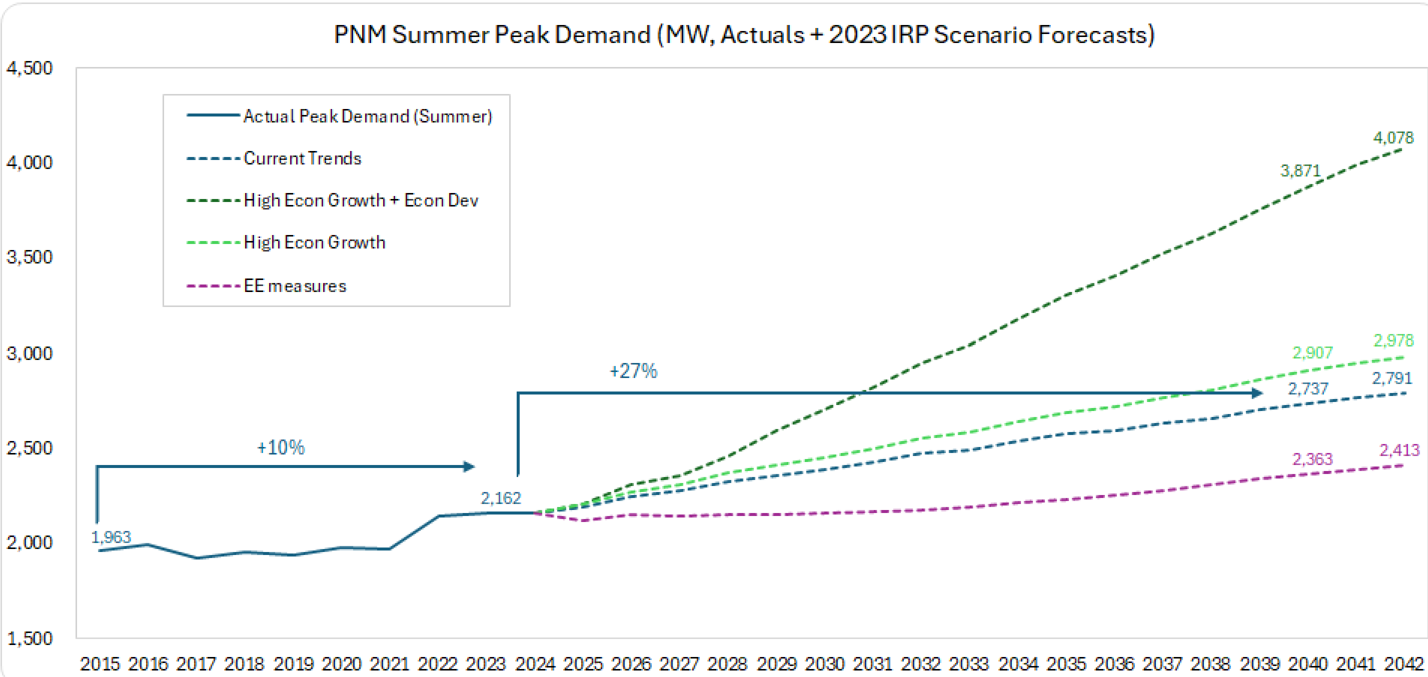


Figure 15

As New Mexico becomes more dependent on an increasingly variable pool of generating capacity resources, resource adequacy will become an ever more important consideration in the larger discussion of grid reliability. The Western Electricity Coordinating Council (WECC), the entity responsible for reliability compliance and monitoring in the Western Interconnection, warned that starting in 2026 the number and magnitude of demand-at-risk hours[30] is set to increase substantially from sustainable levels modeled in 2024-25[31]. WECC's analysis uses probabilistic methods to simulate grid conditions and generate a planning reserve margin[32] that adheres to a constraint of 99.98% of demand met for each hour within a ten-year timeframe[33]. The diagram below illustrates how increasing variability in capacity and load impacts the probability of loss-of-load events[34].

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[29] Reliability Metric Reporting, 17.9.589.1 NMAC
[30] Hours where generating capacity is not sufficient to meet electricity demand
[31] Western Electricity Coordinating Council. (2023). "Western Assessment of Resource Adequacy".
[32] The planning reserve margin is the percentage by which total acquired generating capacity exceeds the peak load
[33] This risk tolerance threshold equates to one day of demand-at-risk hours in ten years
[34] An event where demand is unable to be served by procured generating capacity

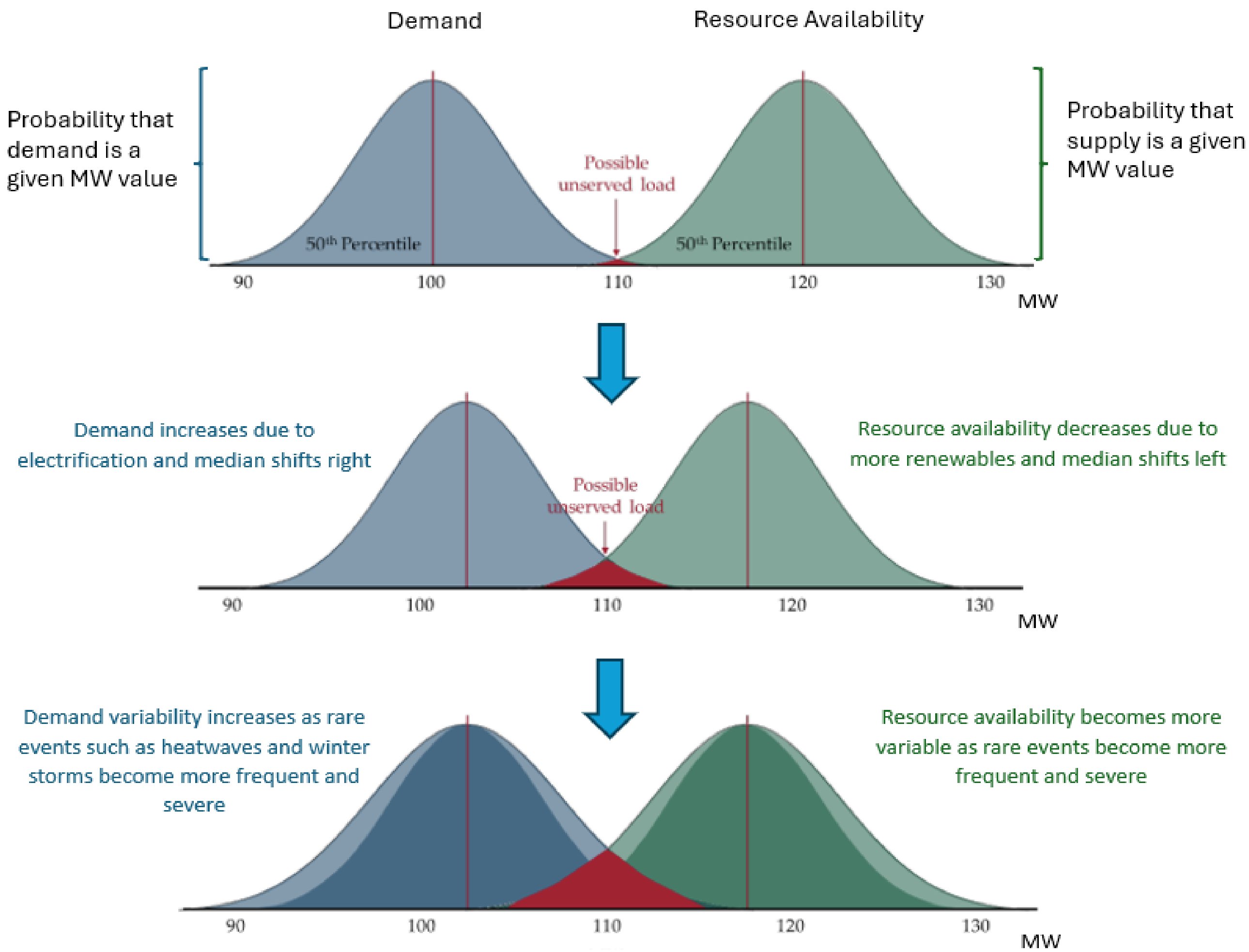

Figure 16 *(Source: Western Electricity Coordinating Council, modified and annotated by NM ECAM)*

The compounding effects of heightened demand, reduced resource availability, and a more variable demand and supply pairings will require additional amounts reserve capacity at utilities. WECC forecasts that the Desert Southwest[35] planning reserve margin needed to comply with NERC-imposed loss-of -load risk thresholds will have to increase by three percentage points by the end of the decade (Figure 17).

[35] WECC subregion for grid reliability monitoring that includes Arizona and New Mexico

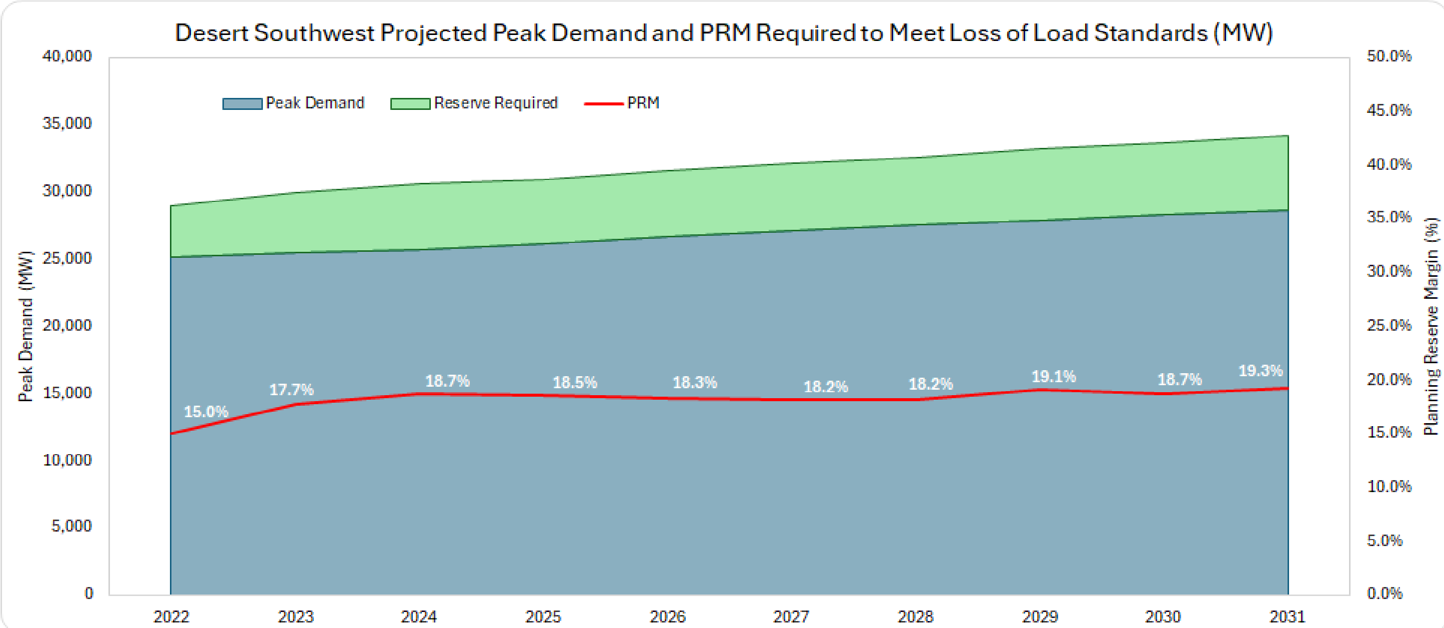

Figure 17 *(Source: Western Electricity Coordinating Council 2021 forecast, developed and modified by NM ECAM)*

III. Energy Affordability in New Mexico

Highlighted as a key component of the modern grid in ECAM's 2021 Baseline report, affordability continues to frame energy infrastructure planning in New Mexico as recent cost of living increases have reduced real income for many New Mexicans[36]. Sensitivity to the cost borne by ratepayers in upgrading the grid is imperative given that the most immediate impacts of these initiatives on residential end-use consumers will likely be financial[37]. Under the current status quo, paying for the upfront costs of large-scale infrastructure projects and cutting-edge technology will require rate hikes and riders that distribute fixed cost investments across ratepayers and co-op members[38]. Additionally, some technologies that are part of the typical suite of grid upgrades will change how residential customers are billed for the energy they consume. Advanced metering infrastructure, for example, will enable utilities to charge time-of-use rates that fluctuate throughout the day and year. Such measures have the potential to increase the average price a consumer pays per kWh of electricity consumed (see TOU pricing section of this report).

a. Electricity Rates and Bills

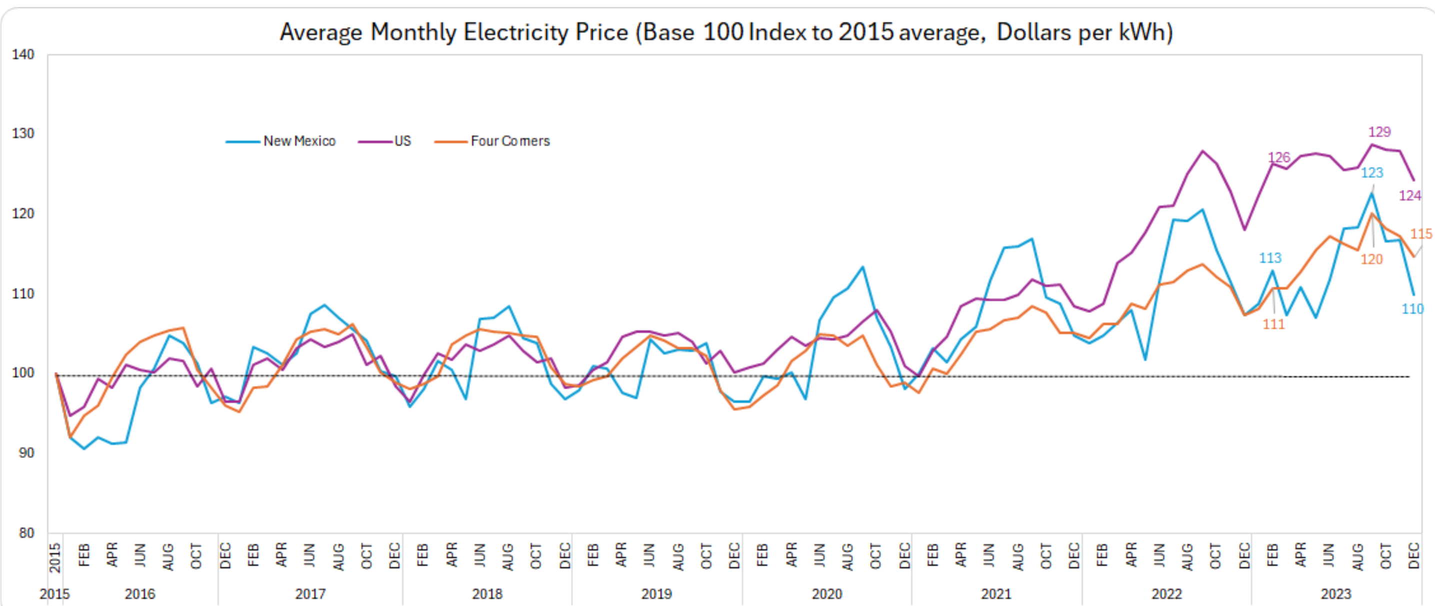

Figure 18

Electricity prices in New Mexico currently follow an inclining block rate design based on usage. After exceeding predetermined blocks of kWh usage within a billing cycle, rates increase along a stepwise function. Fixed charges reflecting the maintenance costs of physical infrastructure and riders to fund utility projections and initiatives are

[36] U.S. Census Bureau, Real Median Household Income in New Mexico, FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/MEHOINUSNMA672N, June 8, 2024.
[37] Kaczmarski, Jesse. "Essays on the Economics of Grid Modernization." (2023). https://digitalrepository.unm.edu/econ_etds/142
[38] New Mexico Public Regulation Commission Case, 22-00058-UT, Public Service Company of New Mexico's Application for Approval of Grid Modernization Plan

collected in addition to volumetric charges per kWh of electricity consumed. Prices multiplied by the quantity of electricity consumed in different rate blocks plus the fixed costs make up a typical New Mexican electric bill.

Figure 18 shows aggregated reported monthly utility revenue figures divided by electricity sales for the defined geographies to arrive at an average price per kWh that captures both volumetric sales and fixed charges. The average price of electricity in New Mexico is less than that of the U.S. but tracks a similar upward trend (Figure 18). Per kWh prices in New Mexico have increased roughly 16 percent from 2019 levels, driven by inflation and increasing usage within SPS' service territory which has higher average rates vs. PNM and EPE[39].

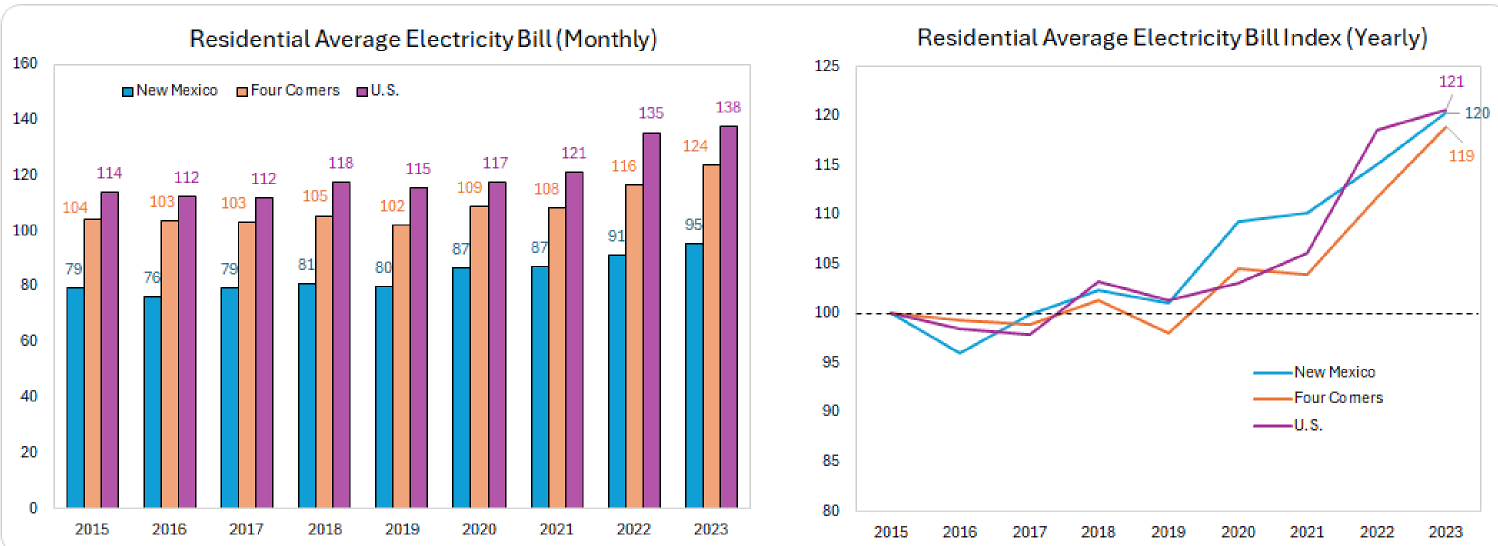

Figure 19

Although average monthly electricity bills are comparatively lower in New Mexico relative to surrounding states and the nation, percentage increases of 20% over the last decade have tracked those of United States and Four Corners region (Figure 19).

b. Energy Burden

Affordability concerns warrant a deeper understanding of the energy burden[40] New Mexicans face. Grid modernization solutions in the state should reflect decision-making that is attuned to potential impacts on low-income communities and focused on measures that shield low-income households from increased costs.

[39] U.S. Dept. of Energy. Form 861-M

[40] Energy affordability is often assessed using energy burden, a metric that indicates a share of income spent on utilities

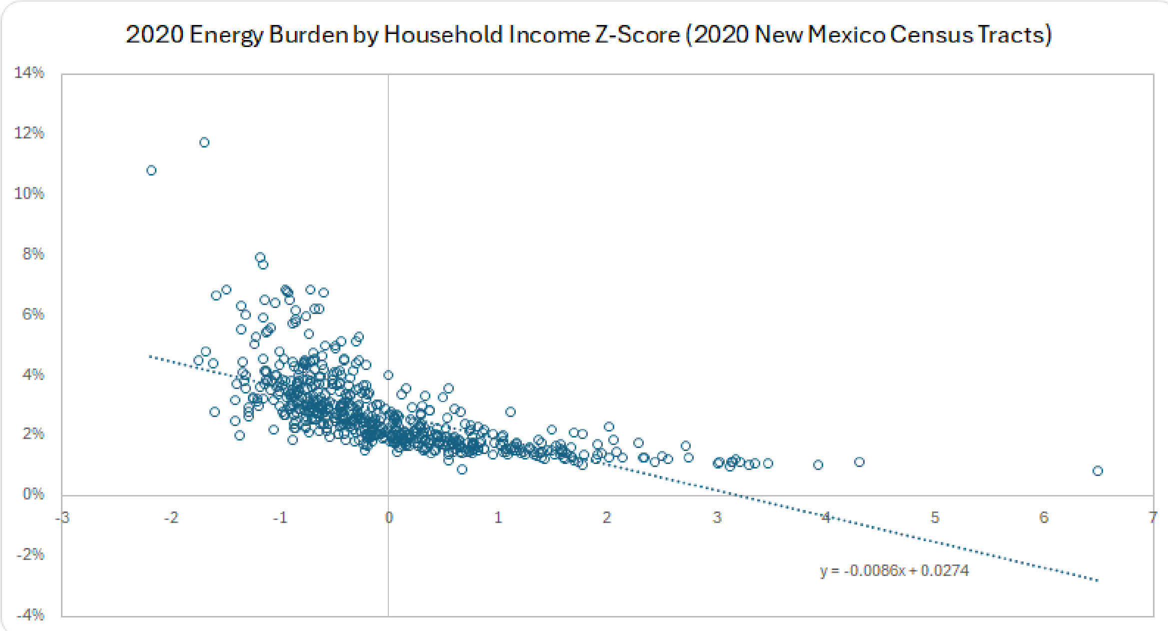

Figure 9

New Mexico Average Energy Burden Statistics by % Area Median Income					
	Income Band	Energy Burden	Energy Cost	Households	Income
Mid- High Income	>100% AMI	1%	$1,716	383,284	$115,996
	80%-100% AMI	3%	$1,585	74,073	$50,672
Low Income	60%-80% AMI	4%	$1,533	83,632	$38,167
	30%-60% AMI	6%	$1,436	118,582	$24,771
	0-30% AMI	14%	$1,467	133,184	$10,435
	Statewide	2%	$1,607	792755	$72,047

Figure 10

Households whose energy burdens exceed 6% percent are considered to be "energy poor"[41]. Unsurprisingly, as a household's income decreases, the household's energy burden is likely to be greater (Figure 10). American Community Survey (ACS) data from 2021 indicates that the average energy burden in a given New Mexico census tract increases by a factor of roughly 8.6 basis points for each standard deviation that tract's median household income is below the statewide mean (Figure 9).

c. Rural and tribal energy burden

On an absolute basis, annual energy expenditure exceeds the statewide average by a considerable amount for a significant proportion of low-income households in New Mexico. Figure 20 highlights the urban-rural divide in household energy expenditure in New Mexico, showing how energy costs can vary by location and compound the effects of low household income on energy burden.

[41] Drehobl, Ross, & Ayala. (2020, September). How High Are Household Energy Burdens? American Council for an Energy Efficient Economy.

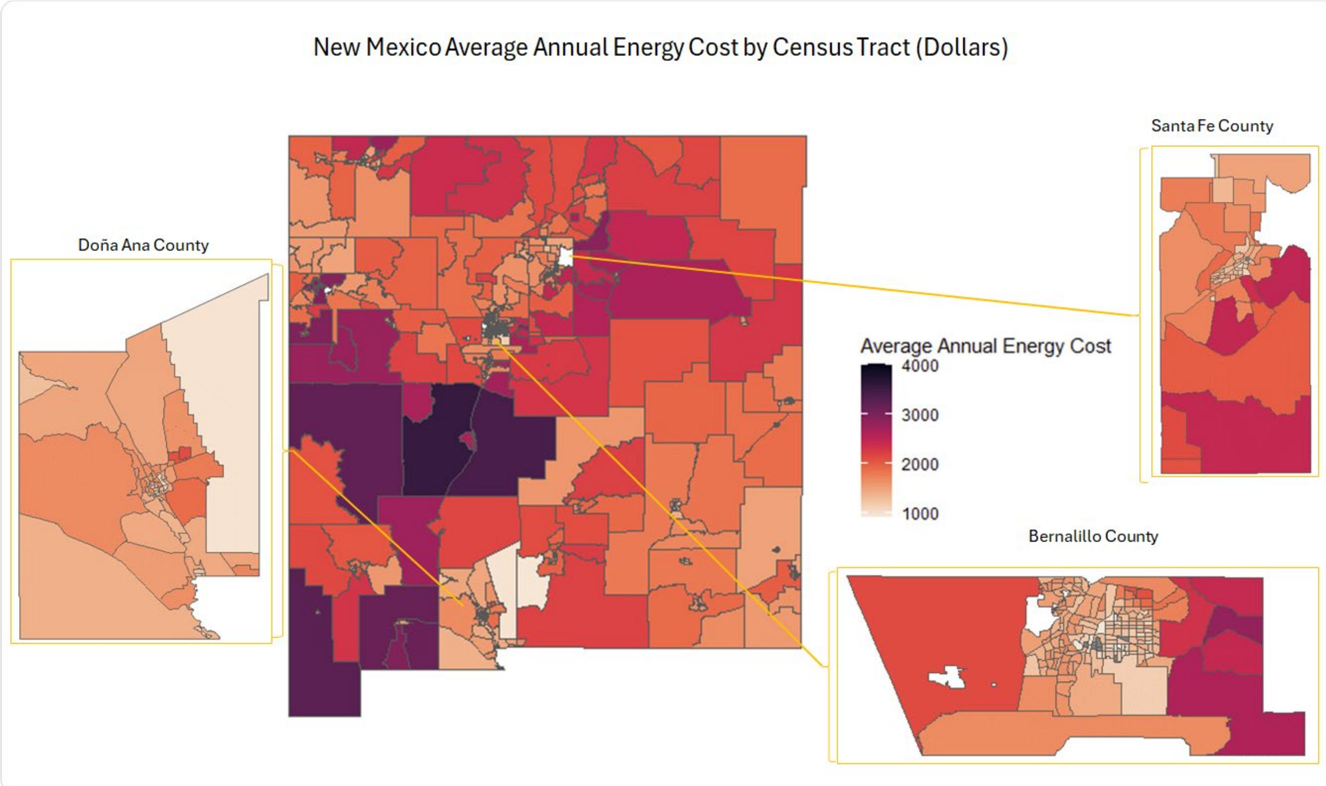

Figure 20

The interaction between geography, demographics, and income shows how the severity of household energy burden varies on a localized basis. Average annual household energy expenditures for rural and tribal areas in New Mexico exceed the statewide average by 21% and 19%, respectively (Figure 21). Moreover, as median household income decreases, the likelihood of rural and tribal communities paying more for energy increases. ACS 2021 data shows that for every standard deviation a rural census tract's median income falls below the statewide average, annual household energy expenditure increases by an average of $73.21. This increase nearly doubles to $136.55 if more than 70% of the census tract identifies as American Indian (Figure 21). The most acutely energy burdened census tracts in New Mexico rank among the bottom 15% of all tracts in the state by median household income while also averaging nearly $1500 more per year versus the statewide mean on per household energy costs (Figure 21).

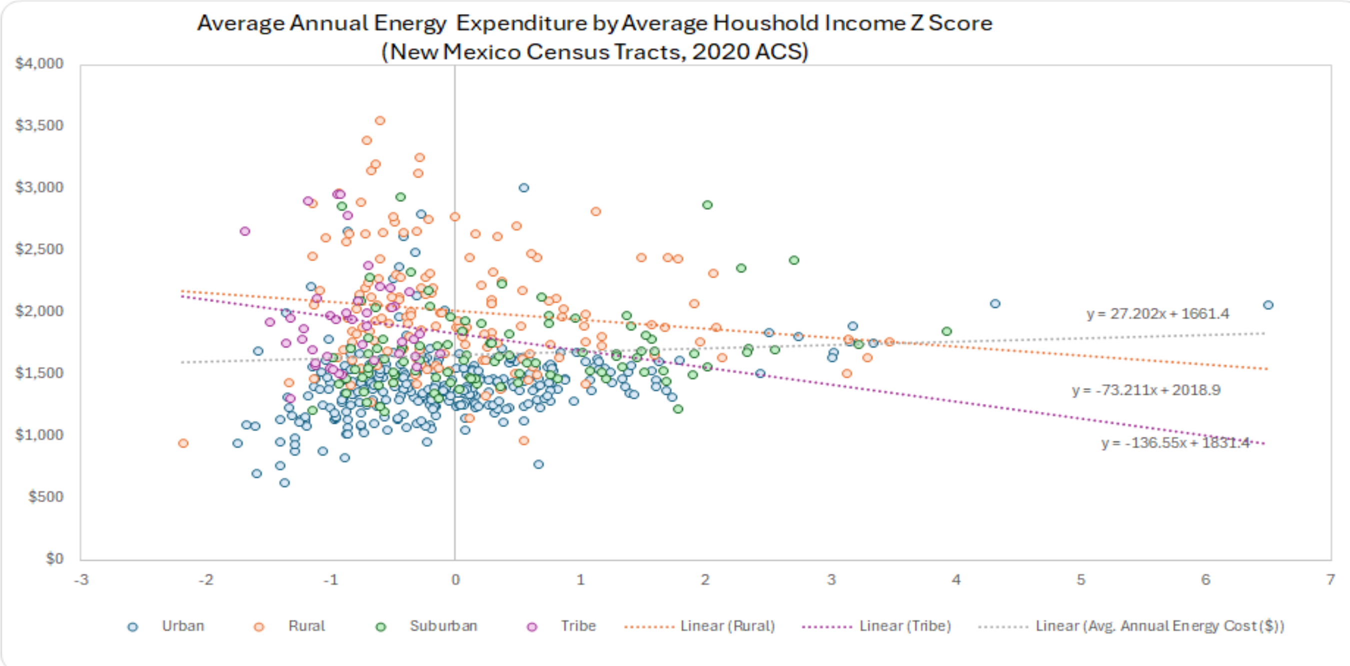

Figure 21

d. Implications of High Energy Burden

High energy burden can exacerbate financial strain, health issues, substandard quality of life, and socio-economic inequality. The EIA's Residential Energy Consumption (REC) survey indicates that roughly a quarter of low-income New Mexicans reduced consumption of necessities to pay their home energy bill in 2020. Almost one fifth of New Mexicans earning less than 80% of median income are receiving assistance (either from utilities or government entities) to afford their energy costs, while 6% of low-income New Mexicans were disconnected from energy service in the year prior to the survey (Figure 22). Nearly 10% of New Mexicans reported keeping their houses at unhealthy temperatures for at least one month in the 2020 RECs survey (Figure 23). Alarmingly, the population share of households always keeping their house at an unhealthy temperature exceeds that of the southwest by 1.4 percentage points and that of the US as whole by 90 basis points (Figure 23).

World Health Organization Housing and Health Guidelines suggest that low indoor temperatures can inflame lungs and induce vasoconstriction which increases the risk of asthma attacks, infection, and cardiovascular diseases while worsening the symptoms of chronic obstructive pulmonary disease (COPD)[42]. High indoor temperatures are associated with a heightened risk of heatstroke, hyperthermia, and dehydration.[43]

[42] WHO Housing and Health Guidelines. Geneva: World Health Organization; 2018. 4, Low indoor temperatures and insulation. Available from: https://www.ncbi.nlm.nih.gov/books/NBK535294/

[43] WHO Housing and Health Guidelines. Geneva: World Health Organization; 2018. 5, High indoor temperatures. Available from: https://www.ncbi.nlm.nih.gov/books/NBK535285/

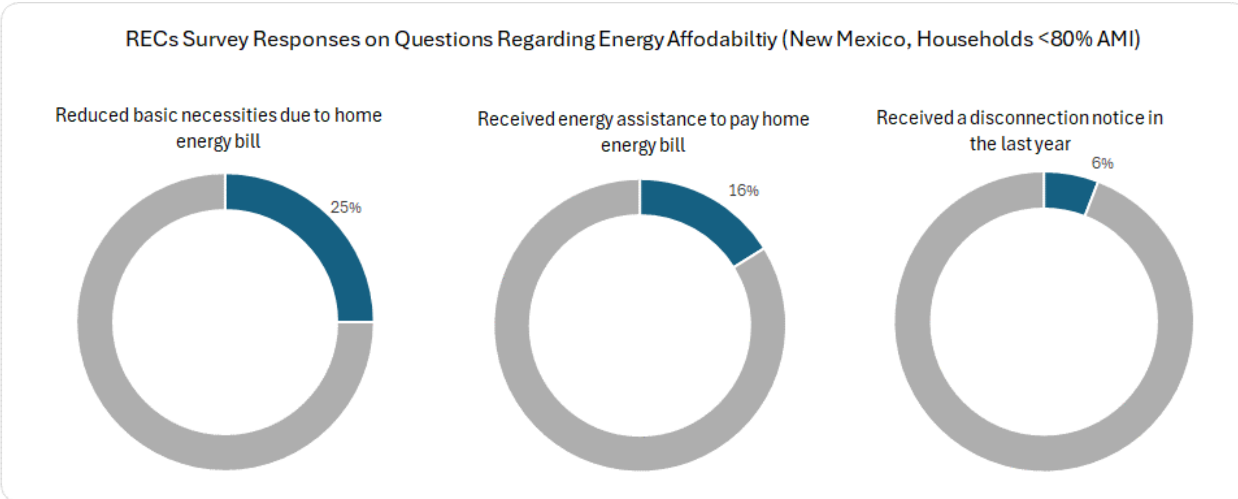

Figure 22

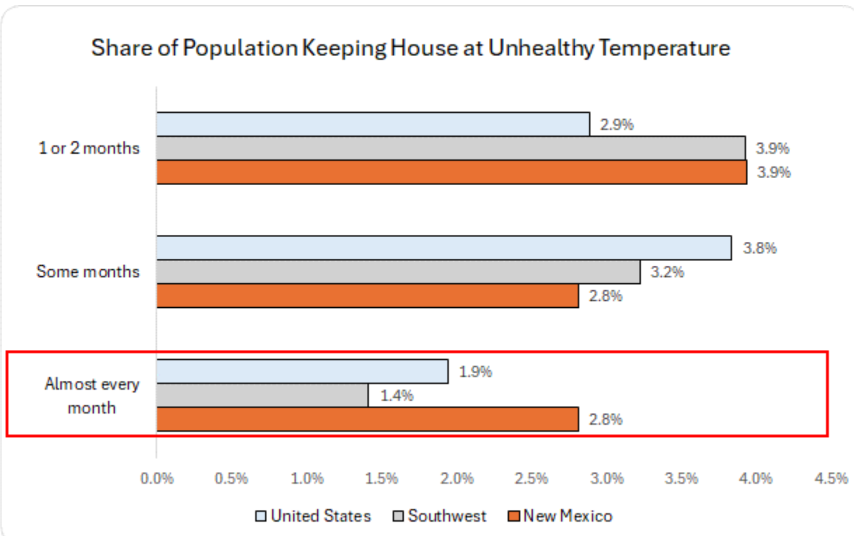

Figure 23

e. Housing and energy affordability

Housing stock metadata from the National Renewable Energy laboratory's (NREL) ResStock project combined with census microdata and the 2020 EIA RECS Survey shed light on some of the factors influencing elevated low-income energy expenditure in New Mexico. Figure 24 shows that low-income households in New Mexico, regardless of community population density, consume more energy per square foot on heating and cooling (often a household budget's most energy-intensive line-items) than the statewide average. These effects are amplified in colder and warmer climate zones.

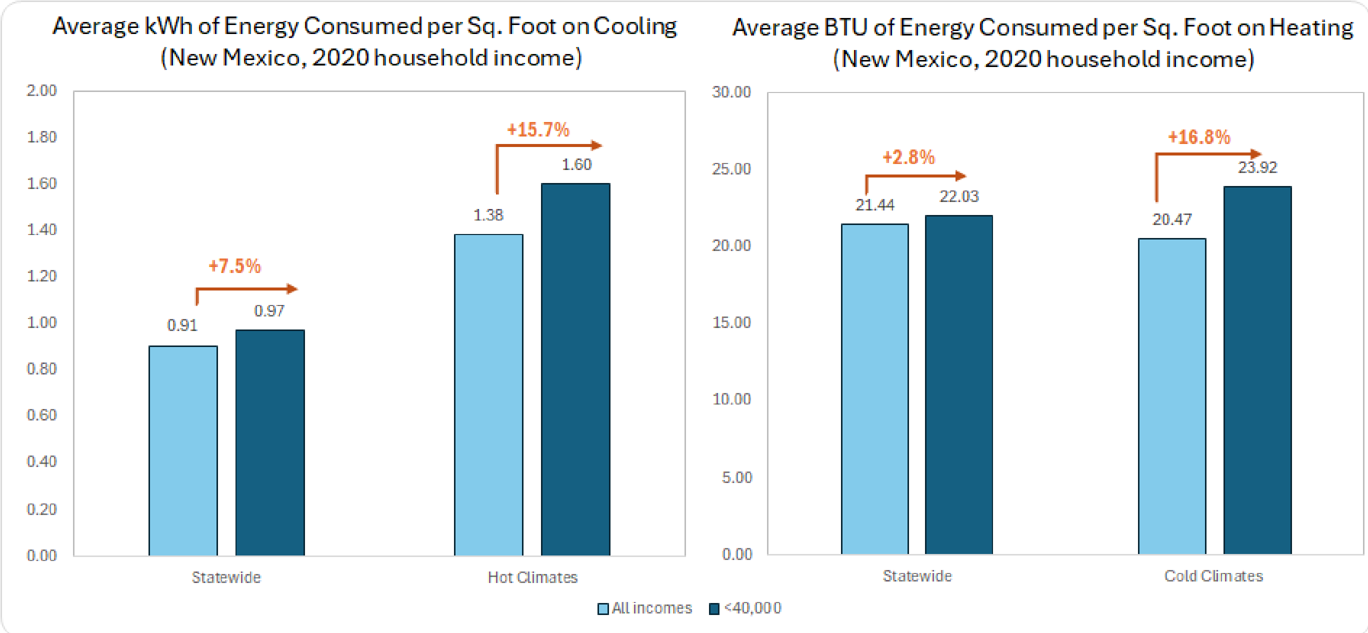

Figure 24

More detailed analysis reveals that low-income building envelopes in the state are disproportionately prone to leakage, with the proportion of low-income homes exceeding 10 ACH 50[44] outpacing the statewide proportion by roughly 7 percentage points (Figure 25).

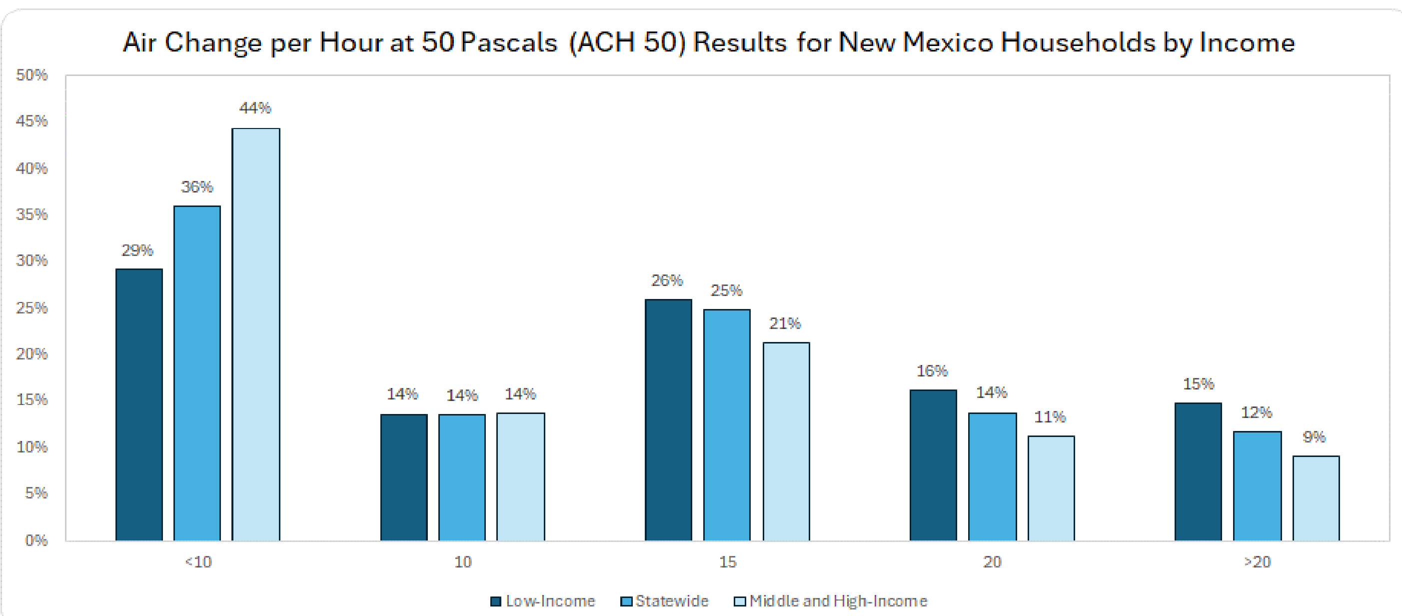

Figure 25

Almost one third of New Mexican households earning less than $40,000 per year assessed overall home insulation as “not insulated” or “poorly insulated” in the 2020 RECS survey while only one fifth of statewide households

[44] A building’s air leakage rate

reported inadequate insulation (Figure 26). These assessments were reaffirmed in ResStock metadata which showed higher instances of inadequate or uninsulated walls and ceilings among the state's low-income housing stock (Figure 27).

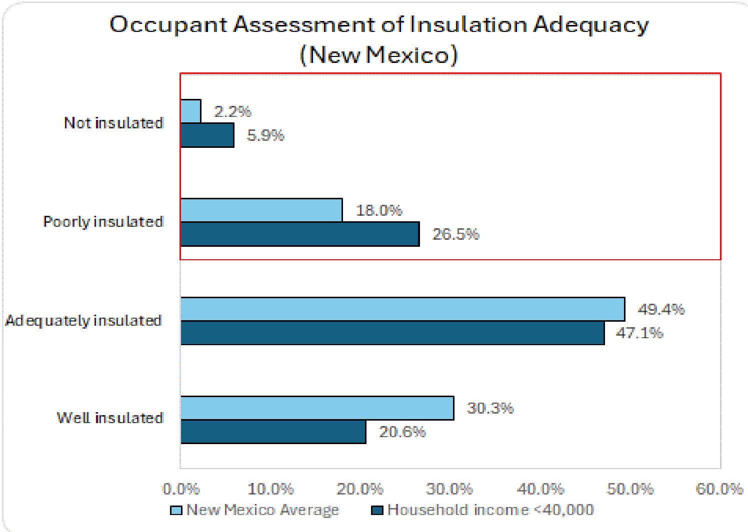

Figure 26

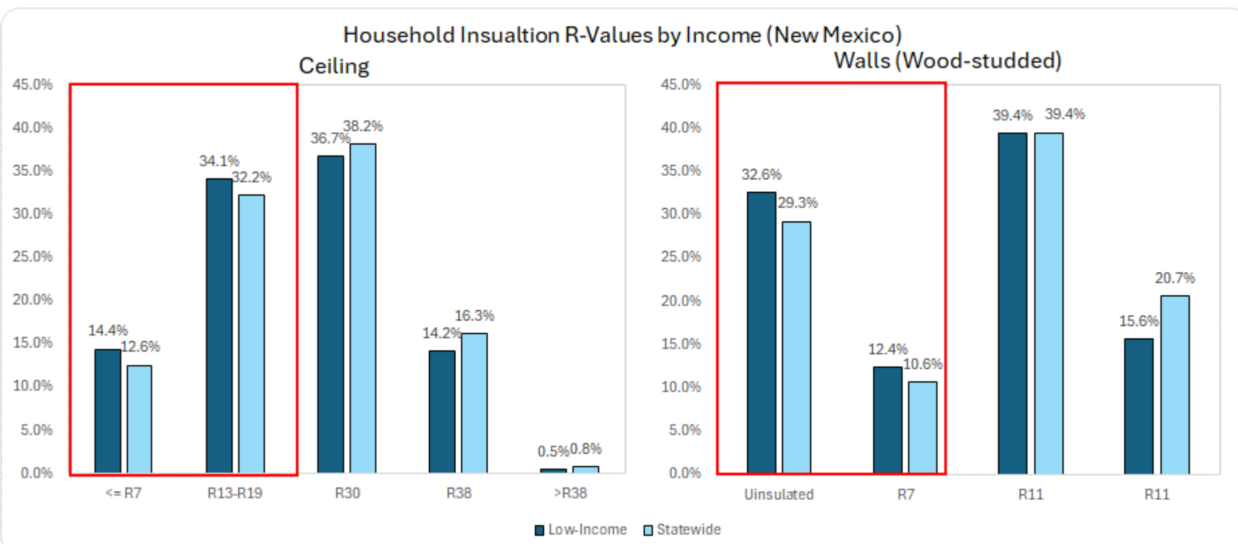

Figure 27

Finally, manufactured homes account for nearly 18% of the New Mexico's housing stock, which is double that of the Four Corners region and three times that of the U.S. as a whole[45]. Households earning below 80% of Area Median Income disproportionately reside in manufactured housing and 40% of rural low-income households are manufactured (Figure 10). Over a quarter (27.3%) of manufactured housing in New Mexico was built before the Federal Housing and Urban Development Department (HUD) established building code regulations for manufactured housing in 1976[46],

[45] New Mexico Mortgage Finance Authority. (2020). "New Mexico Affordable Housing Needs Assessment".
[46] 24 CFR Part 3280 - PART 3280—MANUFACTURED HOME CONSTRUCTION AND SAFETY STANDARDS

meaning these houses likely do not adhere to modern energy efficiency standards. Moreover, the useful lifespan of manufactured housing is typically between 30-40 years[47] indicating that nearly half of the state's manufactured housing will require significant upgrades and/or replacement by the end of the current decade, posing future concerns for low-income energy burden.

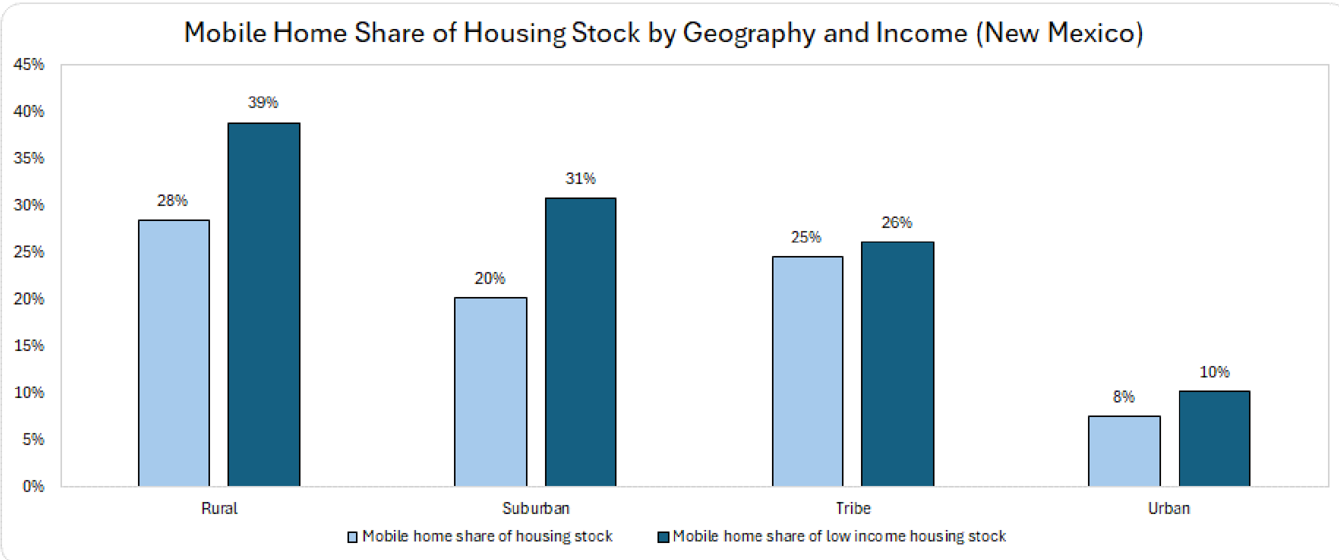

Figure 28

[47] Genz, Richard. (2001). Why advocates need to rethink manufactured housing. Housing Policy Debate - HOUS POLICY DEBATE. 12. 393-414.

Emerging Bottlenecks

To comply with resource adequacy and renewable portfolio standards, growing electricity demand will have to be accompanied by additional generating resources and associated infrastructure. As a result, the energy transition will require significant capital expenditure to finance new projects and meet future demand. This section will examine some of the impediments that utilities currently face in procuring new energy infrastructure and analyze the issue of under-utilization of existing grid assets. The insights gained in this section will provide a foundation for this report's final section on leveraging grid modernization technologies to unlock greater efficiencies at New Mexico's utilities.

I. Interconnection Queues and Supply Chain Constraints

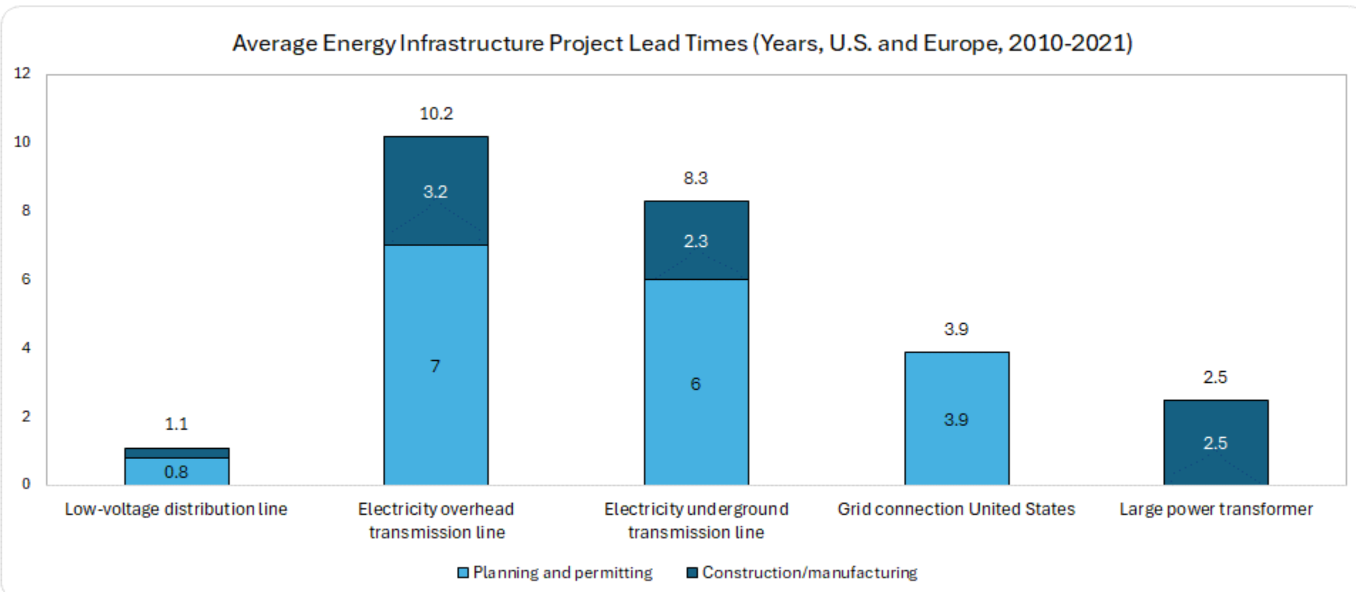

Figure 29 ***Source: International Energy Agency***

In addition to increasing the fixed costs of the grid borne by ratepayers, new utility-scale generation and transmission projects take between 5 and 10 years on average to complete (Figure 29). Due to limited available transmission and substation capacity, lengthy system impact studies, and an outdated cost allocation framework for upgrades[48], over 38 thousand megawatts of generating capacity are currently awaiting interconnection into New Mexico's transmission grid[49]. Roughly three fourths of queued projects in New Mexico are resources procured for in-state utilities and nearly 95% of these projects are renewable generation facilities (Figure 30). Nationally, of projects requesting interconnection, only about one fifth are completed[50]. Moreover, completion rates for renewables are lower

[48] PNM Large Generation Interconnection Procedures and Large Generator Interconnection Agreement Section 3.1.
[49] Rand et. al. (2024). Lawrence Berkeley National Laboratory. "Queued Up: 2024 Edition Characteristics of Power Plants Seeking Transmission Interconnection as 2023".
[50] Ibid.

than those of conventional resources and headwinds to project completion are intensifying as the average time spent awaiting transmission interconnection has grown from three years in 2015 to five years in 2023[51].

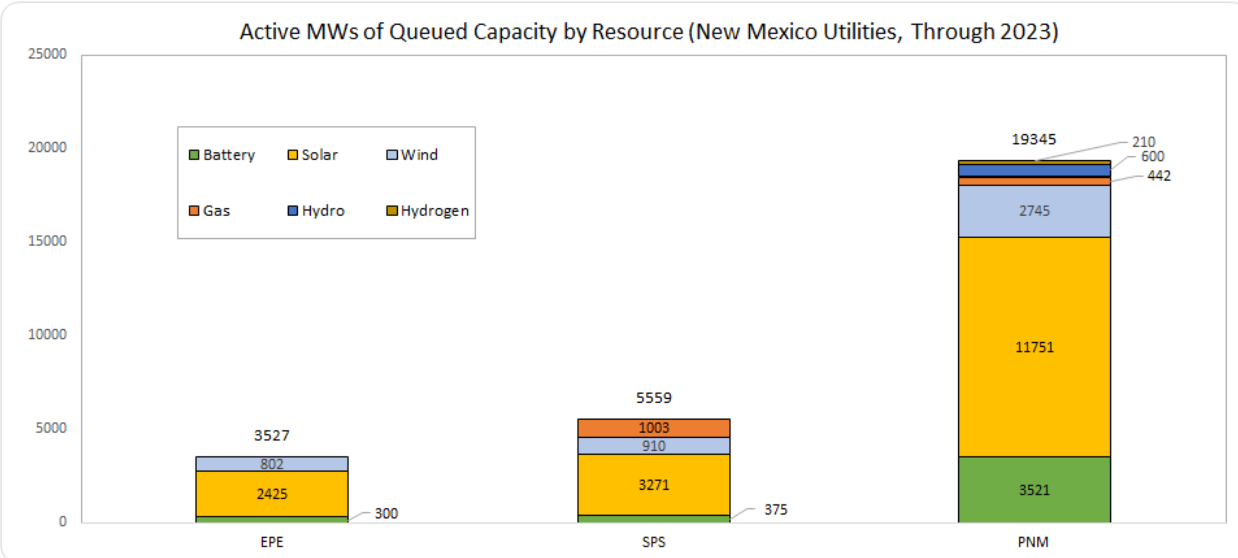

Figure 30 *Source: Lawrence Berkeley National Laboratory*

Compounding elongating interconnection queues, accelerating demand for scarce energy infrastructure components has slowed the pace of global grid buildouts while increasing the cost of energy system improvements and expansion. For example, August 2024 electric power transformer prices rose +70% from 2019 levels (Figure 32) while the global price of copper surged +58% (Figure 31) and the price of grain-oriented electrical steel[52] increased +72% over the same period (Figure 31). Elevated post-pandemic prices reflect shortage conditions in the U.S. market for electric power transformers and associated inputs. Wood – Mackenzie Supply Chain Data shows 4Q23 lead times for power transformers[53] increased +60% from 1Q22 and +240% for generation step-up transformers (Figure 32). Order to shipment times for electric power transformers now span roughly two and half years on average (Figure 32).

[51] Ibid.
[52] A key input for transformers
[53] Transformers step up voltage for long distance and step down for consumption.

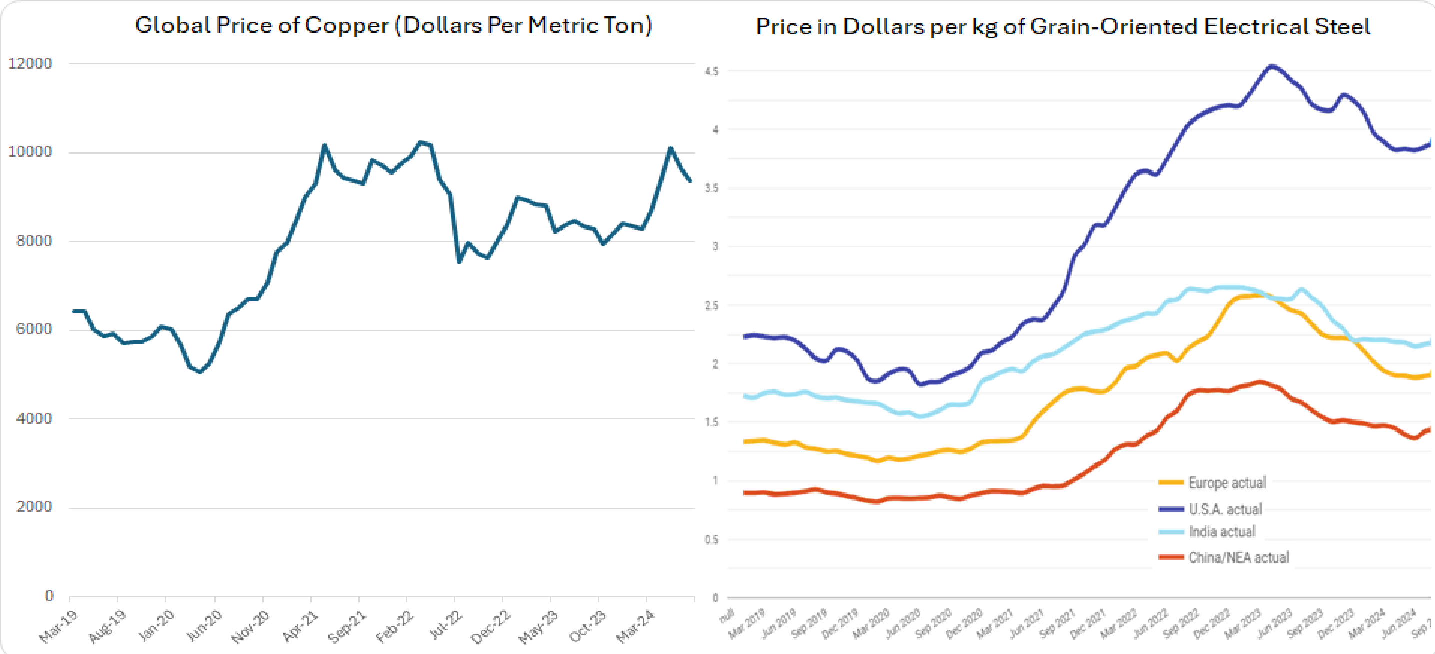

Figure 31 *source: Federal Reserve and BusinessAnalytiq GOES Price Indices*

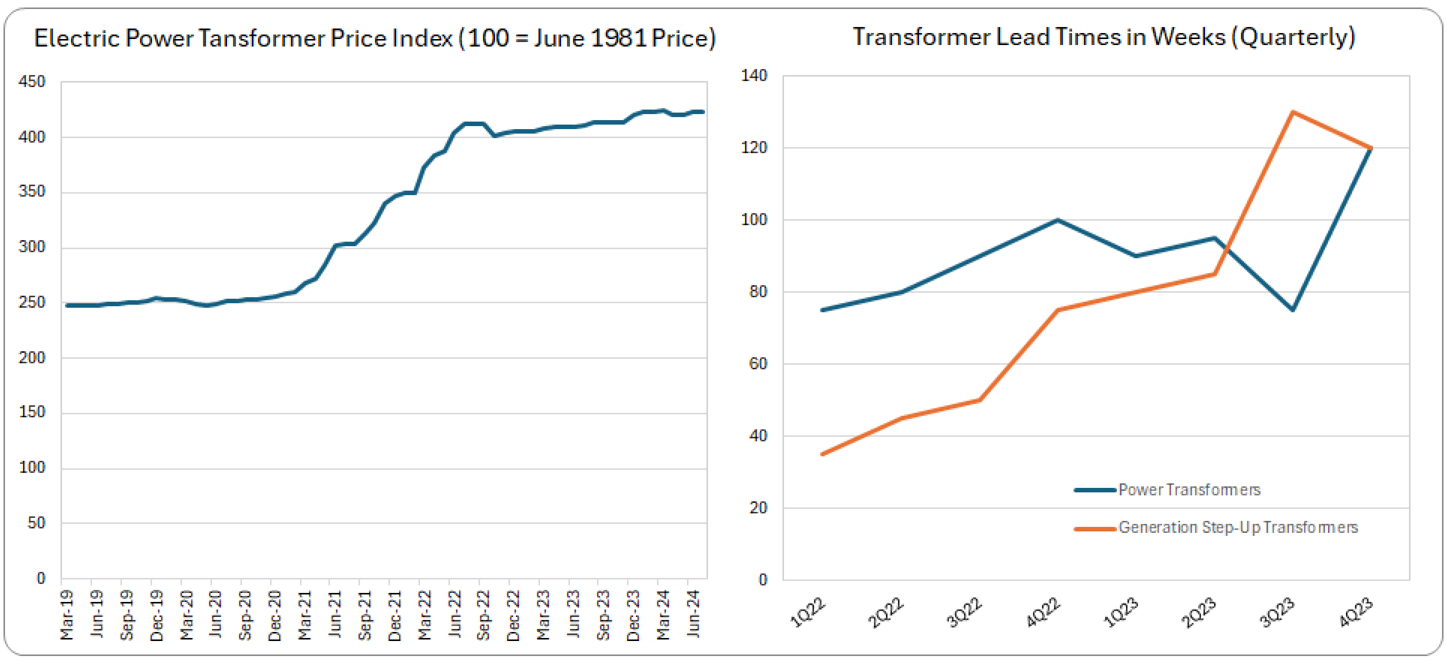

Figure 32 *source: Federal Reserve and Wood Mackenzie*

II. Current impact of emerging bottlenecks

Rising costs and longer transformer lead times as well as growing transmission interconnection queues and congestion are already creating significant issues for New Mexico. As the state attempts to diversify its economy, emerging industries in artificial intelligence and manufacturing are struggling to secure adequate power for new plants, factories, and data centers. Data from New Mexico Partnership[54] show that recent projects interested in establishing sites in New Mexico request to connect 30-60 MWs of load on average, yet nearly a third (28%) ultimately pass up on the state because they are unable to secure a prompt grid connection.

As residential electricity demand ramps up in the coming decades, distribution transformer shortages and grid congestion will not only continue to hamper economic development efforts in New Mexico but could also exacerbate the state's affordable housing shortage. New developments in New Mexico could face difficulty connecting to utility service in the near future, a problem currently impacting new housing construction elsewhere in the U.S.[55] Finally, even when utilities are able interconnect new generation and expand existing grids, upward input price pressure will have to be recovered by increasing rates which raises affordability concerns.

III. Underutilization of existing utility assets

Given long physical infrastructure project lead times, New Mexico will be unable to rely solely on physical infrastructure buildout to meet its near-term and long-term energy transition goals. To continue progressing in its pivot away from conventional electricity generation while maintaining affordability and reliability, the state's power system must utilize existing assets more efficiently via new technology that increases existing capacity and enables non-wires alternatives (NWAs)[56]. Doing so will reduce overall capital expenditure, saving ratepayers money while boosting statewide economic activity and new construction.

[54] New Mexico Partnership is a state-designated, public-private economic development entity
[55] Draffen. (2023). Builder. "Transformer Shortage Leaves Builders Powerless to Finish Thousands of Homes".
[56] Investments in electrical grids that reduce or eliminate the need to upgrade or build transmission or distribution systems.

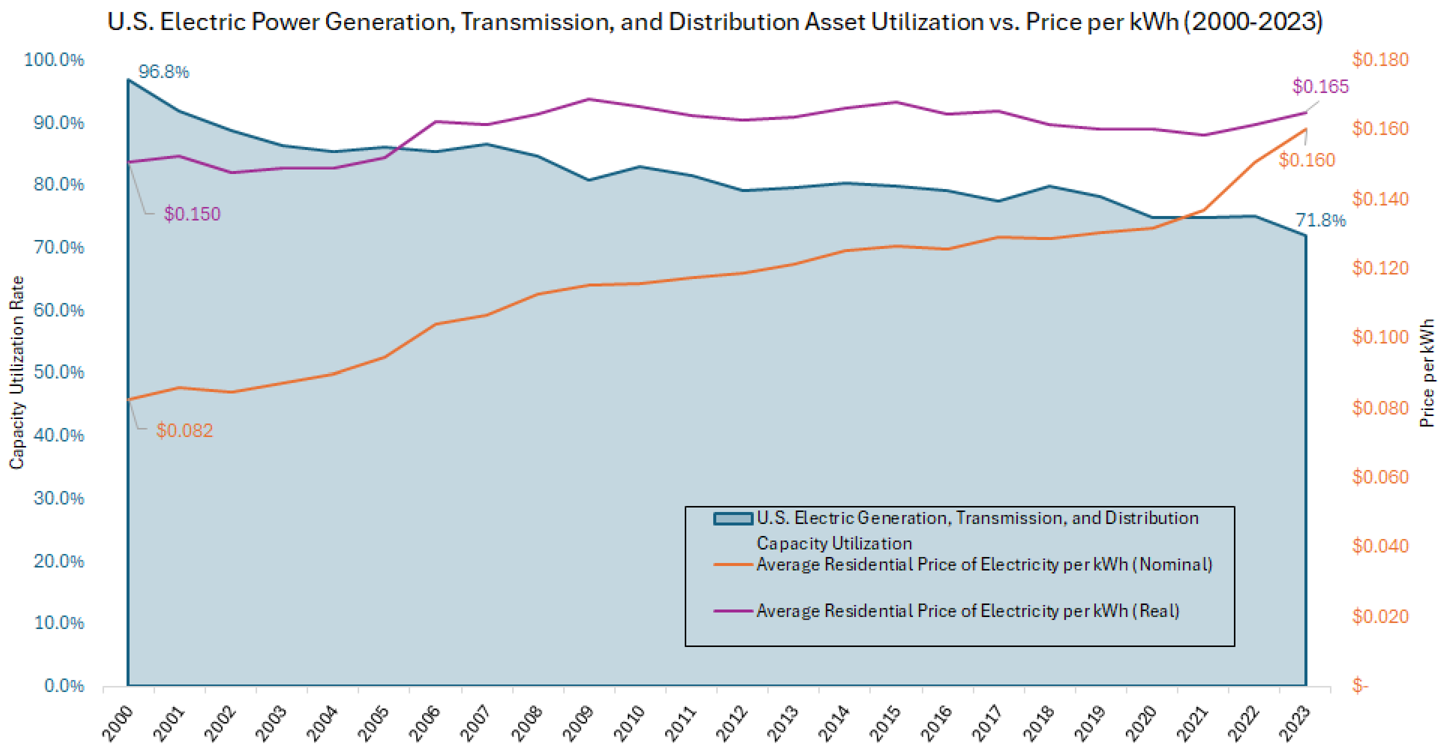

Figure 33

Nationwide data from the Federal Reserve indicate that better utilization of utility assets is possible. Capacity utilization rates for U.S. electric power generation, transmission, and distribution have declined nearly 30 percentage points from a peak of 97% in 2000 to 72% in 2023 (Figure 33). At the same time, the average price of electricity in the U.S. has nearly doubled from $0.086 in 2000 to $0.168 in 2023[57] (Figure 33). The inverse correlation between these two metrics underscores the importance of efficiency as it relates to affordability in the energy sector. Peak demand is at the heart of these inefficiencies. As shown in the resource adequacy section, electric grid capacity is built to serve the system peak load for the highest demand hour each year plus a reserve margin. One implication of building to accommodate the peak is that average load served by the bulk power system is much lower. As peaks grow, ratepayers are increasingly on the hook for capital assets that utilities procure but rarely use.

EIA data show capacity under-utilization at New Mexico's IOUs. Yearly system load factor[58] at PNM, for instance, was 51% in 2023[59]. Natural gas peak generating facilities (as well as associated transmission lines and substations) in New Mexico are one example of an underutilized asset class with capacity factors ranging from 0.11 to 0.42 (Figure 34).

[57] Adjusting for inflation national electricity prices have increased +15% since 2000.
[58] System Load Factor = (Annual Retail Sales in MWh/ 8760) / System Peak in MWs
[59] EIA Form 861 Operational Data 2023

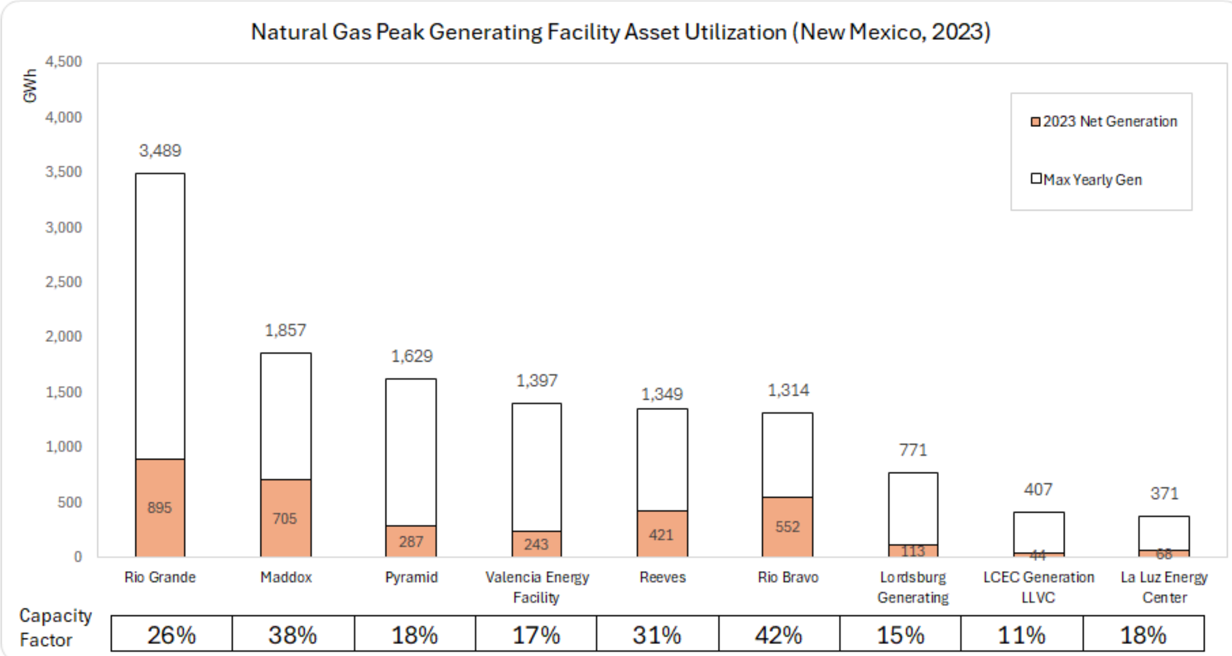

Figure 34

Growing peaks also exacerbate inefficiencies on the distribution grid. Feeder hosting capacity for distributed generation in New Mexico is rated at 100% of the minimum load served[60]. As a result, flexible demand[61] that takes place during a peak (but could be shifted to off-peak times) limits the hosting capacity of existing feeder lines and associated infrastructure (substations, transformers, etc.). Utilities' current inability to encourage or take advantage of flexible load necessitates more expensive distribution upgrades to accommodate increasing DER interconnection.

A second factor influencing asset underutilization in New Mexico is outdated capacity rating methodology and slow adoption of the latest grid-enhancing technologies (GETs)[62]. Maximum transmission conductor capacity is rated using static methods that do not account for real-time weather and line-sag conditions. This rating methodology results in more conservative line ratings which limit transmission capacity utilization[63]. Combined with strategically sited storage, the advanced topology optimization software, and power flow controls, dynamic line rating could expedite the interconnection of renewables currently in the state's queue without building new transmission lines.

Finally, New Mexico's cost-of-service regulatory framework disincentivizes utilities from choosing more efficient GETs, demand side resources, and non-wires solutions in place of high value physical infrastructure upgrades that utilities (and shareholders) can earn a return on. Furthermore, utility revenue in the state is dependent on volumetric sales of

[60] N.M.A.C § 17.9.568
[61] Demand that is not time constrained
[62] Technologies that maximize the transmission and distribution of electricity using existing infrastructure.
[63] White et. al. (April 2024). U.S. Department of Energy Loan Programs Office. "Pathways to Commercial Liftoff: Innovative Grid Deployment" page 5.

electricity, which discourages utilities from promoting energy efficiency and conservation beyond the stipulated percentage of total retail sales mandated by the New Mexico Public Regulation Commission.

3. Grid modernization as a solution

Grid modernization is a key tool for achieving efficiencies in the energy system that synchronize the goals of the energy transition. By deploying the latest grid-enhancing technologies and animating new markets that incorporate distributed resources to flex demand to off-peak times, New Mexico can increase asset utilization and achieve a more efficient power grid that is reliable, affordable, and clean. This final section will take inventory of current grid modernization actions in progress at the state's utilities and provide recommendations for three areas concerning grid modernization policy going forward:

1. cultivating enhanced demand flexibility via peak shifting/shaving
2. improving the capacity of existing transmission infrastructure, and
3. aligning utility incentives with the present era's energy transition goals via regulatory changes

I. Status of grid modernization in New Mexico

In putting forth grid modernization plans for PRC approval, investor-owned utilities in New Mexico have taken the first steps toward better asset utilization. Figure 35 illustrates the technologies approved by the Public Regulatory Commission in the initial grid modernization dockets for the state's three investor-owned utilities, following authorization in the 2020 Energy Grid Modernization Roadmap Act. The most significant development has been regulatory cost recovery for a smart meter (Advanced Metering Infrastructure) roll-out in New Mexico. Advanced Metering Infrastructure (AMI) provides access to more granular energy usage data which plays a critical role in grid modernization. As utilities and regulators seek out opportunities for improved efficiency, hourly time-series data and analysis of energy consumption and grid performance will provide signals for targeted improvements and more precise system management.

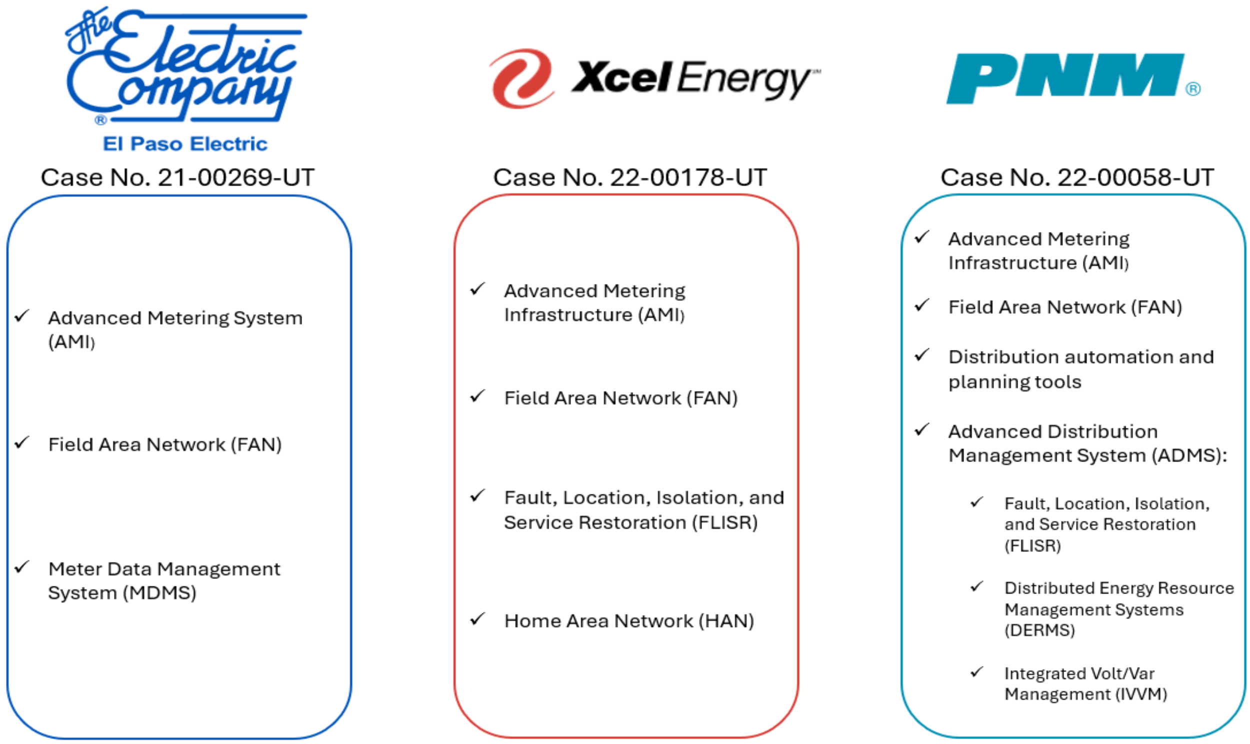

Figure 35

The 2021 New Mexico Grid Modernization Advisory Group (GMAG) [64] , composed of various industry stakeholders[65], described AMI[66] as "foundational" for the development of a modern grid. AMI, when equipped with certain capabilities and functionalities, allows for

1. *Real Time System Monitoring and Management*, which can improve reliability by enhancing visibility into energy flow and usage on the distribution grid. This enables utilities to dispatch maintenance crews faster, potentially predict where faults may occur, and automatically restore power to outage areas in some cases using FLISR[67].
2. *Improved Affordability,* achieved through providing customers with enhanced visibility into their energy usage and highlighting areas where consumption can be reduced, facilitating energy efficiency implementation and demand response.
3. *Increased DER Adoption,* through increased feeder hosting capacity achieved by pairing smart meters with advanced inverters as well as enabling managed EV charging.

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[64] Assembled in response to the directives outlined in the New Mexico Energy Grid Roadmap Act of 2020 NMSA 1978, § 71-11-1 (2020)
[65] The workshops involved representatives from the electricity sector, national labs, academia, renewable energy industry, and consumer/environmental advocacy interest groups.
[66] See https://www.emnrd.nm.gov/ecmd/wp-content/uploads/sites/3/AMI_1.29.21.pdf
[67] Fault Location, Isolation, and Self Restoration (FLISR)

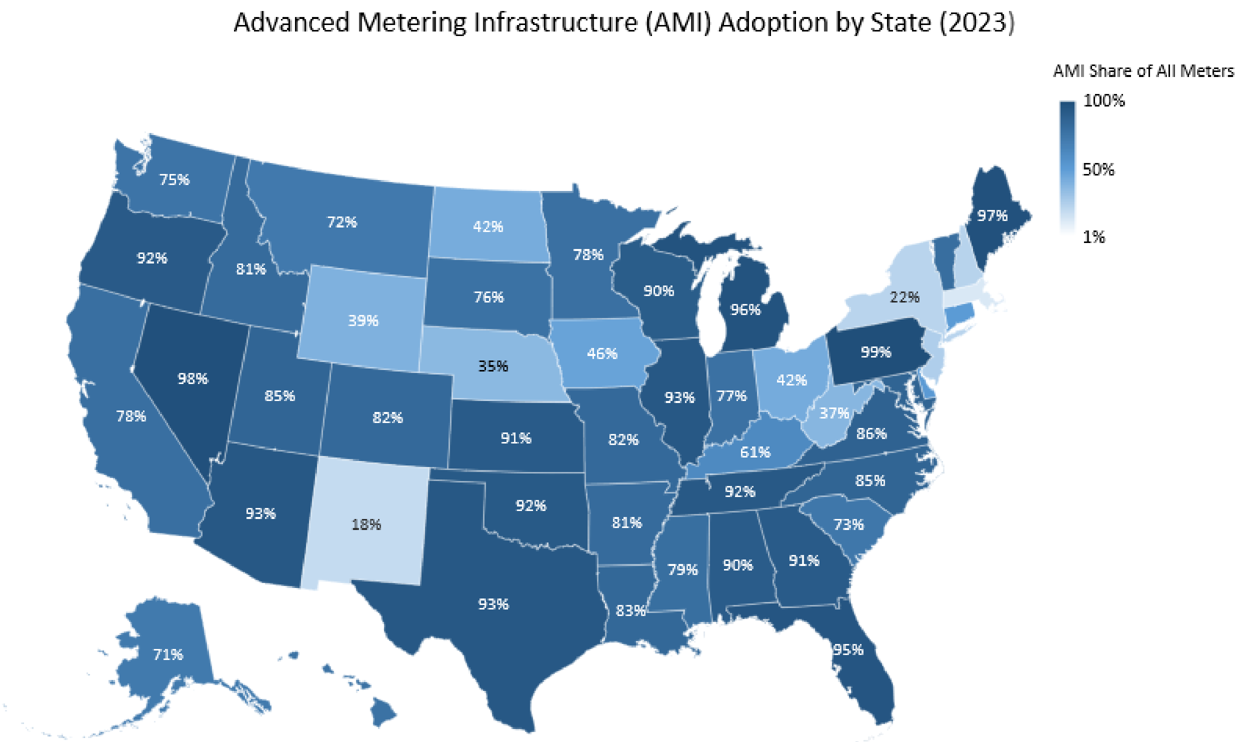

Figure 36

Figure 36 highlights the significance of the approved technologies in Figure 35 as New Mexico currently lags the rest of western states in smart meter adoption. AMI deployment in New Mexico will take roughly 3 years according to PNM's grid modernization plan[68] but provides a basis for additional grid enhancing technologies mentioned later in this report. These technologies will work to alleviate congestion and defer expensive grid upgrades to later dates when supply chain and market conditions for key grid infrastructure components have normalized.

II. Cultivating enhanced demand flexibility for peak load reduction

a. Time-of-use pricing to shave peak demand (Price Based Demand Response)

NMPRC decisions in the 2021-22 utility grid modernization plans outline some next steps for effective implementation of these technologies. Stipulated agreements in the regulator's decision for EPE's AMS approval require the utility to form advisory groups to explore "new pricing programs" and supporting functionalities[69], culminating in a rate case adopting new technologies by 2027[70]. The NMPRC decision in PNM's grid modernization docket requires the utility to file a proposal for mandatory opt-out time-of-day (TOD) rates with the first annual review process of its grid

[68] NMPRC docket # 22-00058-UT
[69] Including Home Area Networks and DERMs
[70] NMPRC docket # 21-00269-UT – Certification of Stipulation – Agreements Regarding Additional Filings, Stakeholder Engagement and Reporting

modernization case[71]. This decision is a departure from an earlier recommendation in SPS's grid modernization case[72] where the PRC allowed the utility to circle back to a time-of-use pilot program following the completion of its AMI roll-out.

As opposed to inclining block rates, time-of-use rates better reflect the price of power supplied during daily demand surges within specified time intervals and seasons. Well-designed peak pricing sends signals to consumers regarding when to consume power, rewarding those who consume energy outside of the peak window with lower volumetric prices per kWh. The result is more efficient matching of supply and demand with respect to resource constraints. Flexible demand is incentivized to occur during off-peak hours which increases asset utilization while reducing reliance on inefficient peak generating facilities. Resulting peak demand reduction from time-of-use pricing is important for deferring capital investment in expensive peaker plants and associated transmission and distribution system capacity[73].

i. Potential Impacts of TOU pricing in New Mexico

Proposed time-of-use pricing exploration in NMPRC's recommended decision for PNM's grid modernization application reflects a similar decision approved by the Colorado Public Utilities Commission in 2020 mandating opt-out TOU rates at Xcel Colorado in conjunction with the utility's smart meter deployment. The Xcel Colorado AMI rollout is nearly complete in 2024 and lends itself as a natural experiment to assess TOU's potential impact on residential bills and demand in New Mexico.

ECAM leveraged causal impact evaluation methods to identify the effects of time-of-use pricing at Xcel Colorado on electricity costs and demand with comparison to PNM as a counterfactual utility given parallel trends in monthly average residential electric sales and pricing inflections[74]. The results showed that summer peak demand has declined from pre-TOU levels since implementation in 2022, where similar reductions have not taken place at PNM (Figure 37).

[71] NMPRC docket # 22-00058-UT- Recommended Decision – Executive Summary 1.3 TOD Rates- Accelerated Adoption
[72] NMPRC docket # 22-00178-UT – Recommended Decision – 5.2 SPS Contested Issues – J) CCAE TOU Programs and CVR Study
[73] Blonz, 2022. "Making the Best of the Second-Best: Welfare Consequences of Time-Varying Electricity Prices," Journal of the Association of Environmental and Resource Economists, University of Chicago Press, vol. 9(6), pages 1087-1126. "Estimated reduction in peak demand increases welfare on the PG&E grid by $159 million over a 30-year period because of avoided capacity investments."
[74] See Appendix B for the full methodological explanation, data sources, and difference-in-differences regression results and analysis

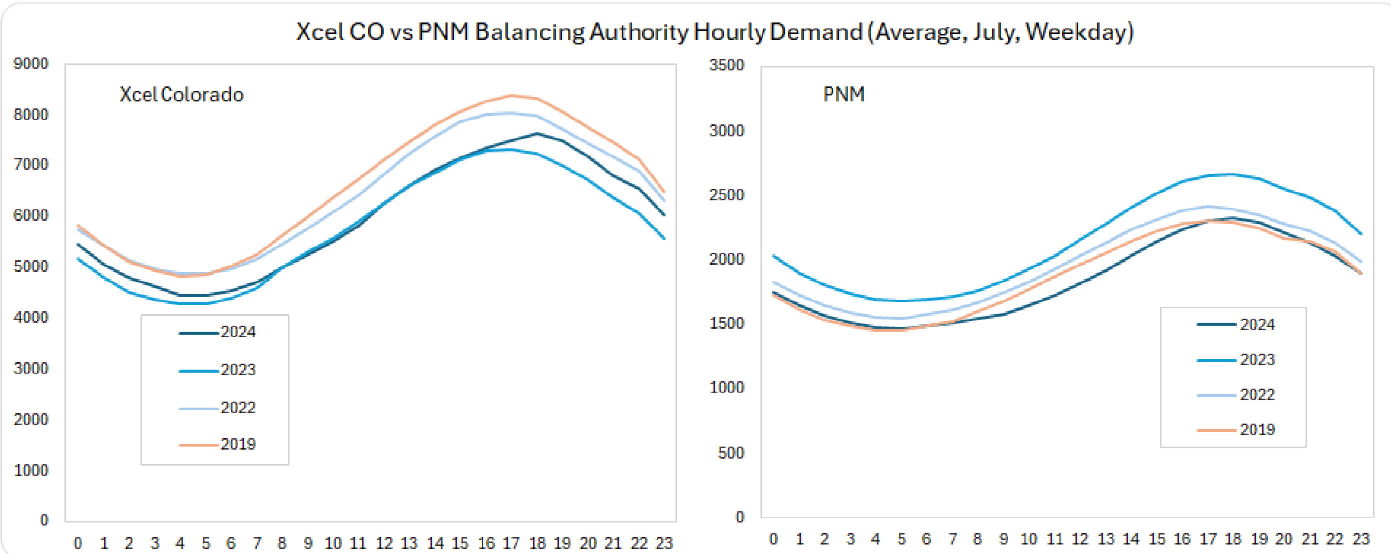

Figure 37

Figure 38 shows the causal effects of TOU pricing on retail electricity prices and demand. ECMD estimates average monthly residential electricity consumption at Xcel Colorado is 23.1 kWh lower than it otherwise would have been had the utility not instituted TOU pricing (Figure 38). Average monthly pricing is estimated to be 1.7 cents per kWh higher than it otherwise would have been at Xcel Colorado following rate changes (Figure 38). The resulting analysis suggests that the pricing effect outweighed the reduction in demand for electricity and the average monthly residential electricity bill at Xcel CO likely grew by $7.74 more than it otherwise would have had AMI not been deployed and TOU pricing not implemented (Figure 38).

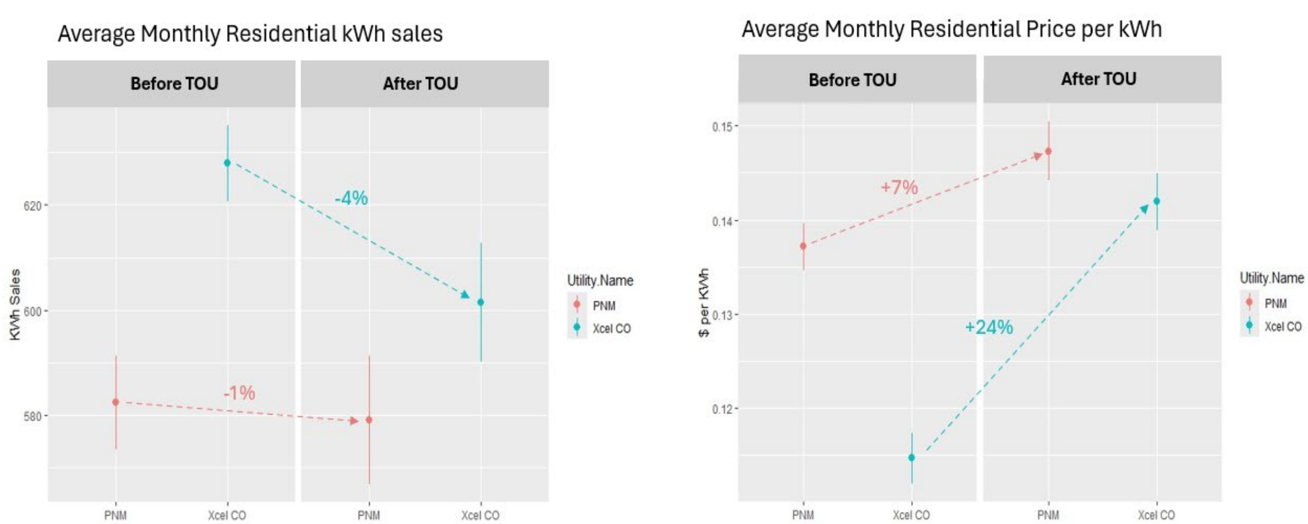

Figure 38

ii. recommendations for mitigating adverse effects of TOU pricing

Findings suggest that TOU pricing at IOUs in New Mexico must be paired with programs to protect low-income ratepayers from even higher energy burdens than they already face. In the Xcel Colorado example, home area networks or automated smart panel upgrades were not emphasized. While municipalities[75] and utility press statements[76] had articulated ways consumers can shift electricity intensive behavior to take advantage of off-peak pricing, time-of-use rates may be more effective when paired with automated processes[77]. Information regarding automated home area networks and smart panel upgrades is not easily accessible and should be prioritized as building and transportation electrification increase in response to broader decarbonization efforts.

Utilities and state energy officials can amplify the demand response impact of AMI deployment and time-of-use rates by educating ratepayers about, and promoting, smart panels and AMI-enabled home area networks that facilitate price-based demand response by linking meters to electrical appliances, EV chargers, and other load contributors. More explicit action can be taken at the utility level to subsidize low-income home area network implementation in conjunction with existing energy efficiency programs to take full advantage of smart appliances already installed as cost-saving measures. These actions would further empower customers to take advantage of dynamic pricing by programming devices to operate at the lowest electricity rate which would optimize the peak reduction potential from TOU pricing.

b. VPPs: facilitating new markets for aggregated DERs and DR as Non-Wires Alternatives

TOU pricing is a catalyst for new markets in aggregated demand response and DERs. Variable prices will likely incentivize distributed solar owners to invest in behind-the-meter energy storage to avoid peak-pricing windows,[78] providing flexibility in dispatching distributed energy for household use. Large quantities of home area networks composed of smart appliances, thermostats as well as distributed generation and storage can be combined into virtual power plants (VPPs) that augment the peak-shaving effects of TOU pricing and function like traditional power plants in the grid services they provide. VPPs are defined by the Department of Energy as, “[tools] used for flexing distributed demand and supply resources with a level of dexterity that has historically only been possible in flexing centralized supply[79].”

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[75] City of Fort Collins Electric Bill Control Handout https://newspack-coloradosun.s3.amazonaws.com/wp-content/uploads/2020/02/TOD-Appliance-Electric-Use-Comparison-Handout-1-20.pdf
[76] Finley, B, 2022, Denver Post https://www.denverpost.com/2022/03/08/xcel-electricity-prices-time-of-use/
[77] For example, appliances that are programmed to run in the middle of the night can relieve customers from the mental load of decision-making surrounding when to perform day-to-day tasks that involve electricity such as running the dishwasher or clothes dryer.
[78] D. Zhao, H. Wang, J. Huang and X. Lin, "Time-of-Use Pricing for Energy Storage Investment," in *IEEE Transactions on Smart Grid*, vol. 13, no. 2, pp. 1165-1177, March 2022, doi: 10.1109/TSG.2021.3136650.
[79] J. Downing et al., “Pathways to Commercial Liftoff: Virtual Power Plants,” The US DOE Loan Programs Office, Sep. 2023.

With the implementation of smart meters across New Mexico, utilities and third-party aggregators will have greater ability to incorporate distributed resources into virtual powerplants that optimize household electricity demand to better manage peak loads. This approach not only reduces the need for expensive peak generation capacity but also helps defer transmission and distribution upgrades, which is valued at approximately $50 per kW of installed virtual power plant (VPP) capacity annually[80]. Figure 39 shows New Mexico already has 145.6 MW DER capacity installed on its grid (excluding electric vehicles and distributed solar which provide additional resources for aggregation).

i. Potential Near-Term DER Growth in New Mexico.

New Mexico Potential VPP Installed Capacity (MW)		
DER Type	**2024**	**2030**
BTM Storage	6.8	8.2
Smart Thermostats	68.7	80.4
Water Heaters	70.1	74.8
Total	145.6	163.3

Figure 39

By the end of the decade, ECAM expects potential installed VPP capacity from the resources above to exceed 160 MWs (Figure 39). Prices for distributed PV and storage are forecast to drop substantially over the next ten years thanks to greater economies of scale achieved by manufacturers and improved efficiencies within global supply chains and the technology itself (figure 40). As result, distributed solar installed capacity in New Mexico is slated to grow +274%[81] by 2035 while the U.S. distributed storage market is expected to grow by 2.5 GW per year between 2024 and 2028[82]. Meanwhile, smart thermostat adoption is set to increase by +17.2% by 2030[83] and ECAM estimates electric water heater adoption will increase by +7% over the next 5 years based on assumptions from the Brattle Group and EIA.

[80] Hledik, R., Peters K. "Real Reliability: The Value of Virtual Power". The Brattle Group. May. 2023.
[81] NM ECAM + NREL dGen Forecasts
[82] Wood Mackenzie Power & Renewables/American Clean Power Association. "U.S. Energy Storage Monitor". June 2024.
[83] Fortune Business Insights. "U.S. Smart Thermostat Market". February 2023.

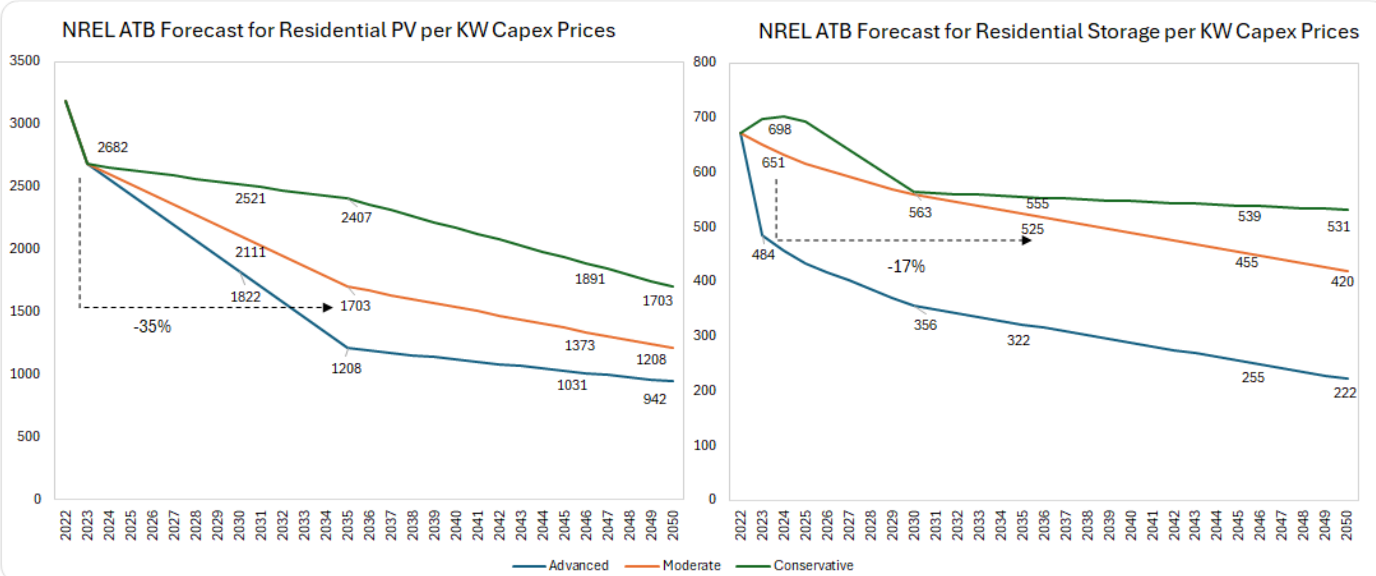

Figure 40

ii. Modeled VPP Potential For Cost-Effective Resource Adequacy in New Mexico

Combining 2030 DER projections with hourly load data, ECAM developed a financial model analyzing the costs and benefits of three typical peak serving assets. The top 163 MWs of hourly electricity load within PNM balancing authority were addressed ten times in 2023 (Figure 41). With projected load growth, the magnitude of peak demand and frequency of operating peak generating facilities is likely to increase by 2030. ECAM modeling suggests that a hypothetical VPP composed of all forecasted installed smart thermostats, electric water heaters, and BTM storage assets could serve the over 1600 MWh of New Mexico's annual peak load at a fraction of the cost and time it would take to construct utility scale storage facilities and natural gas peak generating plants to provide equivalent resource adequacy capacity (Figure 42).

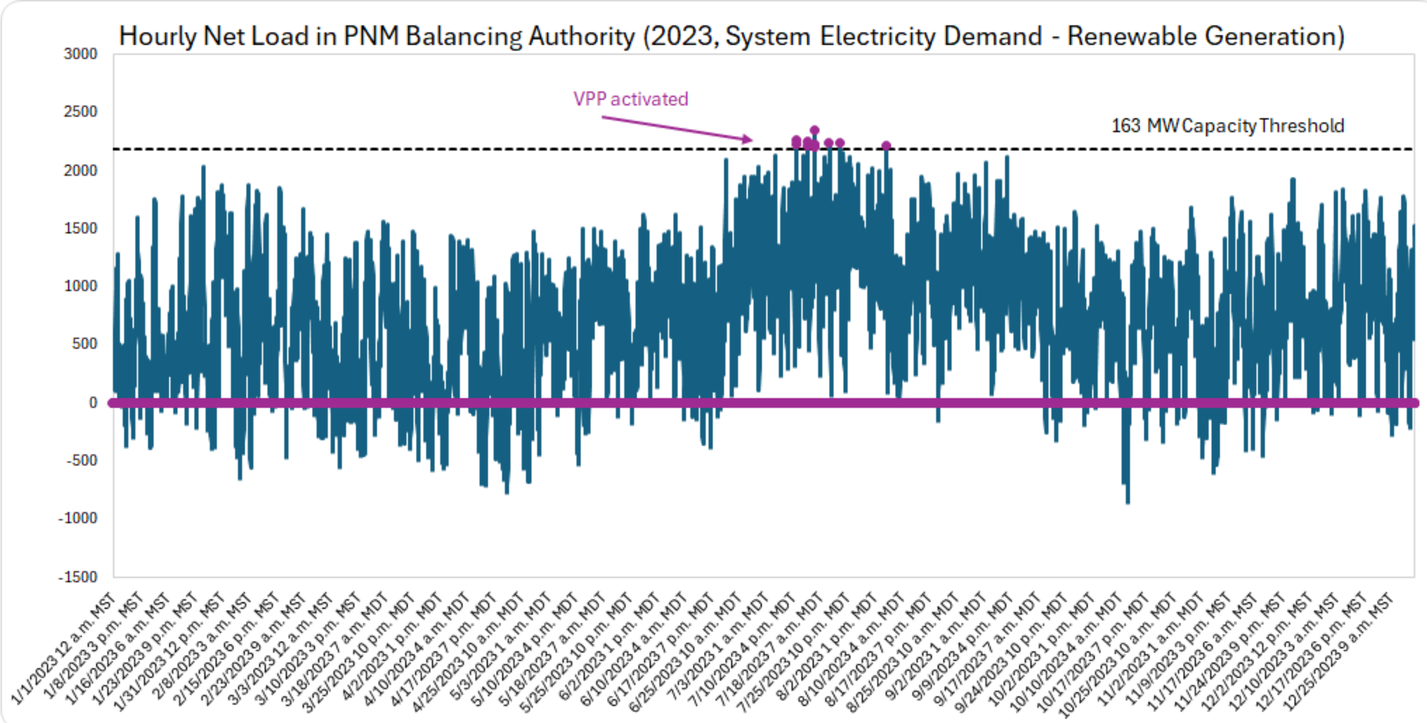

Figure 41

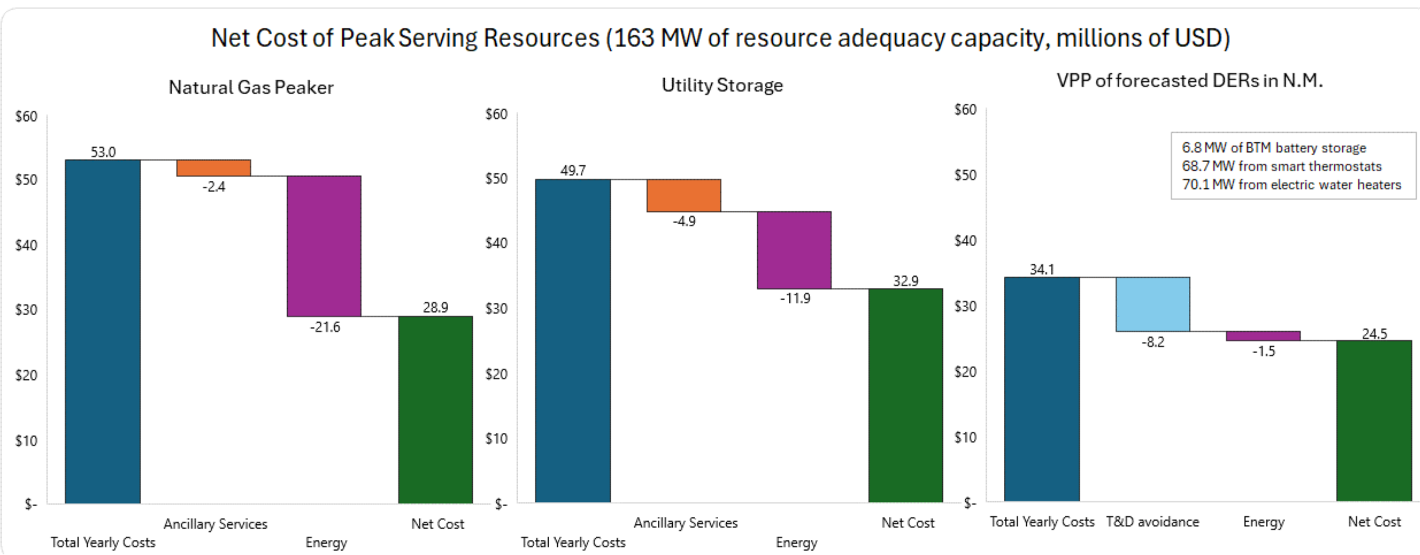

Figure 42

ECAM's modeled 163 MW VPP costs 35% less than a natural gas peaker plant of equal size and 31% less than a utility storage facility on annualized capex basis (Figure 42). Accounting for services provided on a net cost basis, the VPP still outperformed utility storage and the natural gas peaker by 15% and 26% percent, respectively. The net cost calculations above are also likely to be lower than shown above for utility storage and the VPP given the avoided cost of emissions from less conventional peak generation. Additional resiliency and ancillary services benefits provided from behind-the-meter battery storage would further reduce the VPP's annual net cost.

VPP Cost Inputs						
Participant Type	*Participants*	*Per Participant Set-Up Costs*	*Administration Costs Yearly*	*Marketing Per Participant*	*Yearly Per Participant Non-Incentive Cost (DERMS, etc.)*	*Yearly Incentive*
PV+Storage	356	$ -	$ 40,000.00	$ 50.00	$ 140.00	$500
Water Heaters (.39 KW Capacity per participant)	179,714	$ 315.00	$ 40,000.00	$ 50.00	$ 55.00	$25
Smart Thermostats (1 KW Capacity per participant)	68,700	$ 75.00	$ 40,000.00	$ 50.00	$ 43.00	$25

Figure 43

	Line Items	VPP (163 MW)	Gas Peaker (182 MW, 12% Outage Rate)	Utility Storage (163 MW)
	Per KW capex		$ 1,534.50	2911
	Capex Costs (Post IRA Tax Credit)	$ 93,477,470.00	$ 280,138,320.00	$ 332,145,100.00
	Discount Rate	8%	8%	8%
	Lifespan Years	10	20	15
	Annulized Costs	$ 13,930,900	$ 28,532,707	$ 38,804,361
Costs	Yearly O and M Costs	$ 19,276,560.00	$ 24,424,015.52	$ 10,880,000.00
	Transmission Avoidance per KW - yr	$ 15.00	$ -	$ -
	Distribution Avoidance per KW - yr	$ 35.00	$ -	$ -
	Peak energy price at Palo Verde node per MWh	$ 250.00	$ -	$ -
	Total energy saved benefit	$ 407,500.00	$ -	$ -
	MWh per year from BTM	10126.56		
	LCOS per MWh Residential storage	$ 150.00	$ -	$ -
	Ancillary Services per MW		$ 15,000.00	$ 30,000.00
	Energy MWh per year		128509.2	238455.96
Benefits	LCOE per MWh		$ 168.00	$ 50.00

Figure 44

Importantly, ECAM's projections suggest that the hypothetical VPP could generate ratepayer savings of $81.5 million dollars in deferred or avoided transmission and distribution system upgrades over the course of its 10-year lifecycle while providing access to peak services in a matter of 1-3 years vs. 4-7+ years for utility-scale generating and transmission assets[84].

iii. Leveraging VPP Policies in Other States to Maximize VPP Value in New Mexico

Massachusetts provides a template for how utilities, state energy offices, and regulatory bodies can work to design markets that incentivize VPPs while providing compensation to resource owners and optimizing the locational value of distributed resource siting to benefit the grid. The state implemented a clean peak energy portfolio standard in

[84] White et. al. (April 2024). U.S. Department of Energy Loan Programs Office. "Pathways to Commercial Liftoff: Innovative Grid Deployment" page 22.

2020 which mandates a certain percentage of annual retail electricity sales met with qualifying “clean peak resources”[85]. This spurred incumbent distribution utilities to aggregate smart thermostats and BTM storage into demand response VPPs[86] that generate credits necessary for clean peak compliance. The Massachusetts Department of Energy Resources (Mass DOER) enhanced the policy’s ability to defer grid upgrades by issuing seasonal lists of distribution circuits and substations identified for improvements—either due to high distributed PV saturation or peak demand[87]. To maximize the locational value of DERs, the Mass DOER applies a multiplier to the clean peak credits earned by aggregated DERs deployed in areas where they defer or avoid grid upgrades, thereby increasing the utilization of existing grid assets[88] while compensating resource owners for the full value they provide and assisting the utility in meeting its clean peak requirement.

iv. ECAM Recommendations for VPP Adoption in New Mexico

The simultaneous rise in peak demand and the adoption of DERs presents a significant opportunity for New Mexico to leverage behind-the-meter and community assets as virtual power plants. By strategically aggregating DERs and deploying them as non-wires alternatives (NWAs), the state can optimize load management and defer expensive, traditional grid upgrades. This approach not only advances New Mexico's energy transition despite resource constraints but also enhances asset utilization through achieved efficiencies that make the grid more reliable via resource adequacy capacity provided.

VPPs that leverage aggregated DER as NWAs to avoid new peak generation capacity and/or traditional distribution and transmission system upgrades already exist in other jurisdictions, as shown in the Massachusetts example above. Strategic storage siting has also been authorized as a non-wires alternative at PNM[89] and deployed in other states like New York[90] and Arizona[91]. ECAM notes that existing low-income access programs in New Mexico (NM PRC’s Community Solar and ECAM’s Solar For All) provide opportunities to optimize the locational value of third-party storage and solar on the distribution grid (either at a centralized node or as DERs) to defer or avoid upgrades. Planning for these programs should take into consideration where resources can be located to alleviate grid congestion and defer upgrades, lowering rates for all ratepayers while providing bill credits to low-income New Mexicans.

In addition, given the large amount of existing smart thermostats and electric water heaters already installed in New Mexico, IOUs should begin pilot programs that aggregate these resources into peak management VPPs (as was

[85] Massachusetts DOER Regulation 225 CMR 21.00
[86] National Grid ConnectedSolutions Program
[87] Circuits and substations are ranked by PV hosting capacity (connected PV MW capacity / feeder capacity rating MVA) and the annual peak load share of the total feeder capacity rating (Annual Peak Load in MVA/ feeder capacity rating MVA).
[88] Mass DOER Distribution Circuit Multiplier Guide
[89] NMPRC Docket # 23-00162-UT
[90] NYSEG Stillwater Non-Wires Alternative Project
[91] APS Punkin Center Energy Storage Project

mandated in Colorado in 2024[92]) to enhance AMI investments and energy efficiency programs currently taking place. Further, IOUs should explore battery storage VPP programs in existence at utilities like Utah's Rocky Mountain Power[93] and North Carolina's Duke Energy[94] which provide incentives for distributed PV owners to install storage that the utility can dispatch to provide peak services and frequency regulation.

III. Improving the capacity of existing grid infrastructure via GETs

a. Dynamic Line Rating (DLR)

Long queues for interconnection into New Mexico's transmission grid as well as high locational spot price differentials[95] between generating nodes and loads in the Western Energy Imbalance Market underscore the statewide and regional need for more transmission capacity. Because existing transmission lines that host least cost generators may be at capacity, balancing authorities often curtail least cost generation to comply with operational protocols. The resulting suboptimal dispatch of power elevates energy costs for ratepayers[96]. Traditionally, congested lines are eventually upgraded, or the transmission grid is expanded, to alleviate this congestion while increasing costs ultimately recovered from ratepayers.

Existing capacity limits are one factor contributing to transmission congestion. Transmission line carrying capacity (known as ampacity) is determined by the interaction of a conductor's thermal properties with those of the conductor's environment[97]. A maximum safety threshold is calculated after tabulating how the heating effects of electrical current passing through a conductor and solar radiation are offset by radiative cooling and wind[98]. Overheating can cause transmission lines to anneal (potentially damaging the conductor) or sag below an allowable threshold (potentially igniting vegetation)[99]. Currently, balancing authorities and wire manufacturers use static methods to rate lines that are based on conservative assumptions about environmental conditions.[100] Because they don't account for the real time ambient impacts on lines' thermal ratings, the DOE estimates static methods unnecessarily limit existing transmission capacity by 10-30%[101].

Dynamic line rating (DLR) makes use of field area communications networks (FANs) and ambient/lidar sensing technologies to update line capacity ratings more frequently (15-minute intervals) to reflect real-time ambient air

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[92] Martucci, B. "Colorado Law Requires Xcel VPP program by February with Performance-based Tariff". Utility Dive. March 2024.
[93] Rocky Mountain Power Wattsmart Battery Program. "2023 Utah Energy Efficiency and Peak Reduction Annual Report" May 2024.
[94] Duke Energy Power Pair Program. "North Carolina Clean Energy Technology Center". May 2024.
[95] Cai and Jung. (2024). "Transmission Use and Congestion Analysis in the Western States". Western Interstate Energy Board (WEIB).
[96] U.S. Department of Energy. (2022). "Grid-Enhancing Technologies: A Case Study on Ratepayer Impact". Pg. 2.
[97] Karimi S., et al. (2018). "Dynamic Thermal Rating of Transmission Lines: A Review". Renewable and Sustainable Energy Reviews.
[98] Ibid.
[99] Ibid.
[100] U.S. Department of Energy. (2022). "Grid-Enhancing Technologies: A Case Study on Ratepayer Impact". Pg. 5.
[101] White et. al. (April 2024). U.S. Department of Energy Loan Programs Office. "Pathways to Commercial Liftoff: Innovative Grid Deployment".

temperature and wind conditions on the grid[102]. Figure 45 illustrates how dynamic line rating can meaningfully increase the ampacity rating beyond that rated using static methods over the course of a day.

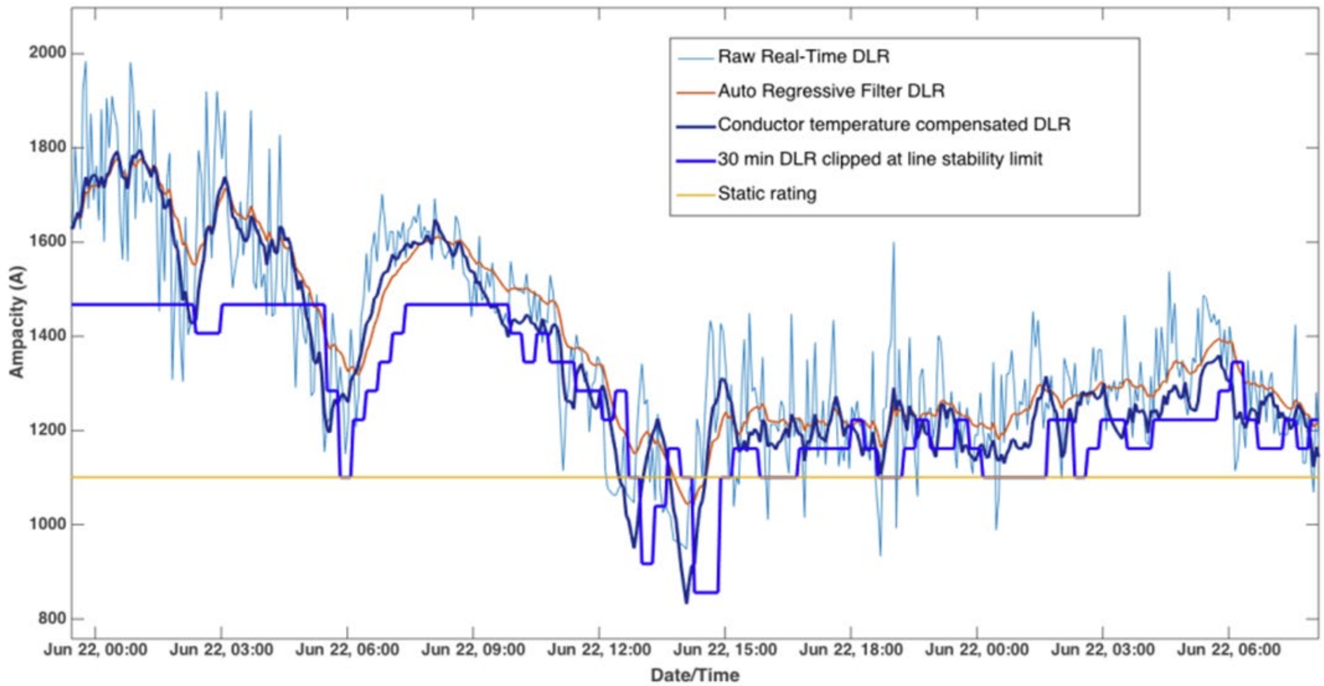

Figure 45 ***Source: DOE 2019 Congressional Report on Dynamic Line Rating***

i. Examples

DLR has already been deployed at utilities across the U.S. with average line capacity increases of 16-25% depending on local conditions[103]. A 2014 DOE study with Oncor Electric in Texas found DLR to be particularly beneficial for increasing transmission capacity serving wind resources. Oncor deployed DLR at a cost of $16,000 to $56,000 per mile where reconductoring and rebuilds would have cost $320,000 to $750,000[104] per mile[105]. While alternative upgrades would have resulted in new ratings up to 140% of the previous static rating, DLRs improved ratings by 110% at a fraction of the cost and time it would have taken to reconductor or construct new transmission[106]. More recent utility pilots in the US have shown capacity increases of over 30%.[107]

European utilities have deployed DLR to a greater extent than their American counterparts with proven cost-saving results. For example, Austria utilized DLR on 15% of its transmission lines to save ratepayers over $17 million in 2016

[102] Ibid.
[103] Idaho National Laboratory. (2022). "A Guide to Case Studies of Grid Enhancing Technologies".
[104] Figures in 2014 dollars
[105] Dept. of Energy. (2014). "Oncor's Pioneering Transmission Dynamic Line Rating (DLR) Demonstration Lays Foundation for Follow-On Deployments" DOE Office of Electricity Delivery and Energy Reliability.
[106] Ibid.
[107] Federal Energy Regulatory Commission. (2024). Docket No. RM24-6-000. "Implementation of Dynamic Line Ratings". Advance Notice of Proposed Rulemaking Section III. A. Demonstrated DLR Benefits 2. Domestic Examples.

from avoided congestion[108]. Slovenia has increased its transmission capacity by 22% since 2016 using DLR while France deployed the technologies to avoid a $30 million line replacement and interconnect new wind generation[109].

ii. Fire risk management benefits

Notably, DLR also reduces transmission capacity below static methodology during periods of extreme heat and high winds, a beneficial feature for wildfire risk mitigation. When lines are equipped with LiDAR sensors for DLR, grid operators have greater situational awareness in monitoring real-time line clearance conditions. This greater visibility can also aid in fire prevention activities indicating where to clear vegetation[110].

iii. Recommendations

While FERC Order 881 requires transmission providers in organized markets to update line ratings hourly based on ambient air temperature, this mandate did not apply to non-RTO/ISO transmission operators such as the PNM Balancing Authority in New Mexico[111]. ECAM views dynamic line ratings as essential for cost-effective near-term transmission capacity expansion amid constrained resource procurement conditions and rapidly expanding load. Specifically, DLRs can help facilitate expedited interconnection of energy-only resources and storage as opposed to network resources that require system upgrades as a condition for reduced curtailment risk.

Acknowledging significant differences in market structure, ECAM also suggests exploring ERCOT's "connect and manage" interconnection policy as a complement to expanded transmission capacity from DLR. Connect and manage can be used as template to guide the interconnection of large generators going forward, especially as New Mexico looks to deregulate wholesale energy markets, as a means for reducing queue times for renewables with the tradeoff of increasing curtailment and/or collocating storage capacity. ECAM notes that ERCOT connected 2.5 times more capacity than PJM in 2022 despite serving an annual peak load half the size of PJM's[112]. LBNL interconnection queue data from 2023 suggests roughly half (49%) of generation projects currently awaiting interconnection in New Mexico are applying for transmission access as a network resource. This service requires more extensive analysis and frequently produces results that necessitate costly upgrades to the transmission system to be borne by the requesting generator. Specified upgrades trigger projects to pull out of the queue resulting in a cascade of wasted time and effort for the balancing authority. Connecting more projects as energy resources, as is done in Texas, can prevent this issue while reducing curtailment risk if paired with dynamic line rating and/or storage as a transmission asset.

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[108] Federal Energy Regulatory Commission. (2024). Docket No. RM24-6-000. "Implementation of Dynamic Line Ratings". Advance Notice of Proposed Rulemaking Section III. A. Demonstrated DLR Benefits 2. International Examples.
[109] Ibid.
[110] Federal Energy Regulatory Commission. (2024). Docket No. RM24-6-000. "Implementation of Dynamic Line Ratings". Advance Notice of Proposed Rulemaking Section I. A. Transmission Line Rating Proceedings 3. Comments Supporting DLRs.
[111] Federal Energy Regulatory Commission (2021). Docket No. RM20-16-000. Order No. 881.
[112] Norris. T. (2023). "Beyond FERC Order 2023: Considerations for Deep Interconnection Reform". Duke University Nicholas Institute for Energy, Environment, and Sustainability.

b. Storage as a Transmission Asset

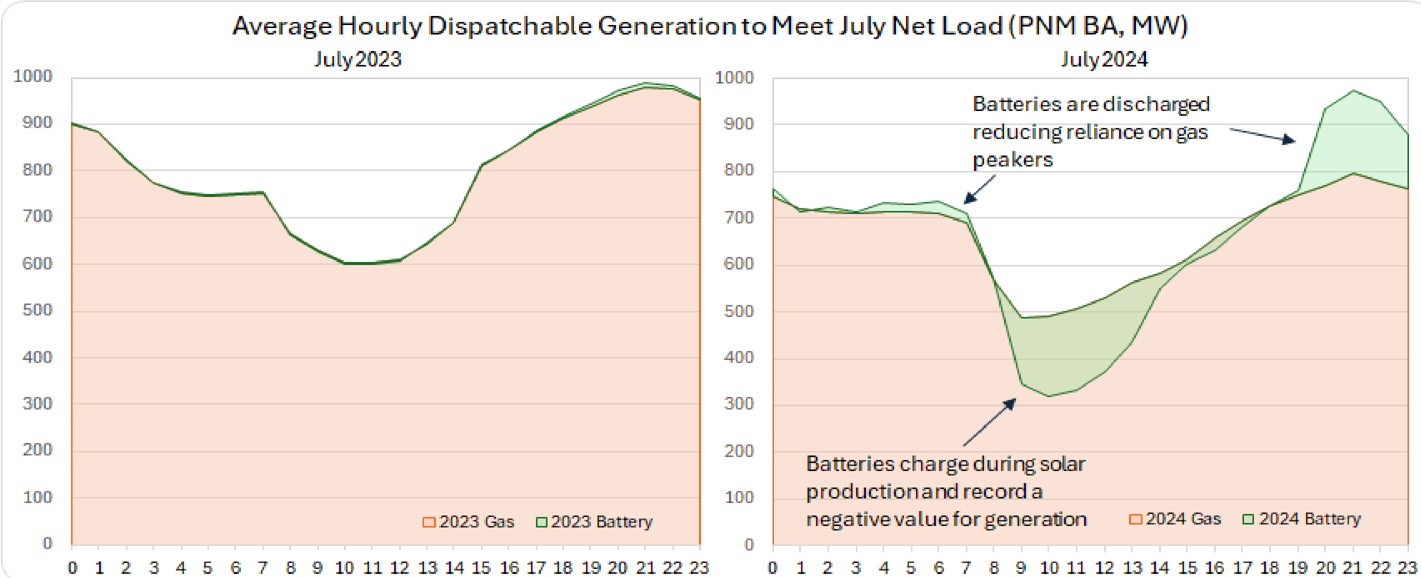

Figure 46

Utilities in New Mexico are already dispatching new battery storage facilities within the PNM balancing authority (Figure 46). This shift aims to reduce reliance on natural gas combustion for meeting the morning and evening load peaks that occur before and after solar energy reaches its full potential at midday. With utility-scale storage prices slated to decline between -15% and -45% by the end of the current decade, 4-10 hour duration batteries are likely to proliferate across the U.S. grid in the coming years to compliment renewable generation (Figure 47).

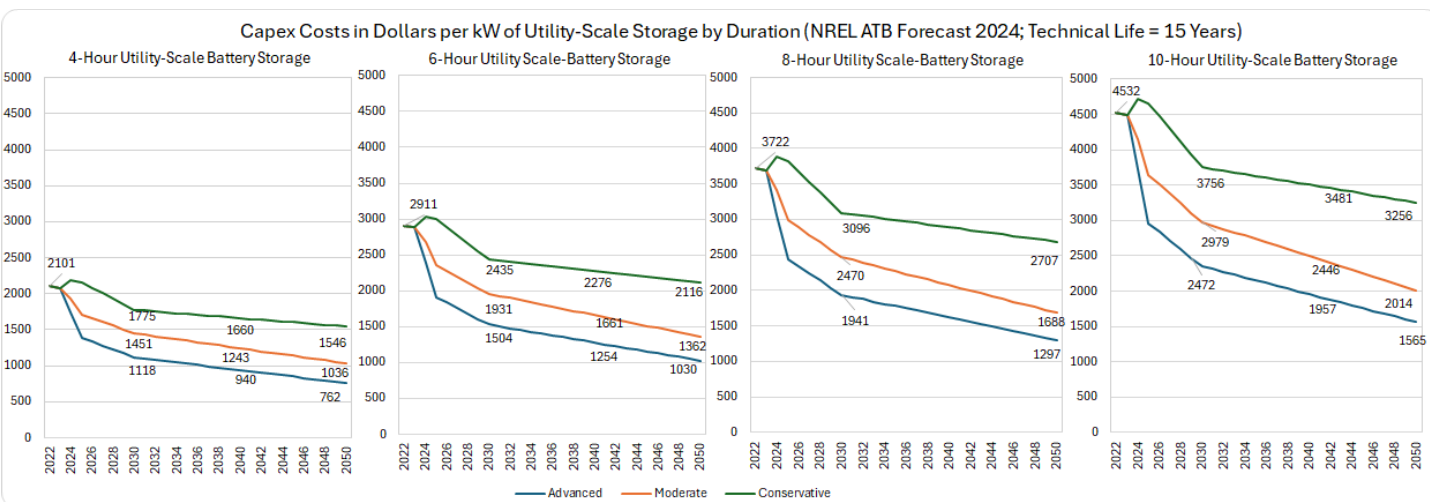

Figure 47

While energy storage projects are primarily thought of as a clean dispatchable generation resource and a resiliency asset, they are also increasingly being deployed as alternative solutions to traditional transmission upgrades. Battery storage can be used to enhance the ability of existing transmission lines to carry higher power flows by balancing line loadings and mitigating system voltage or stability issues via ancillary services provided. This serves to reduce renewable energy curtailment in periods of low demand resulting in more efficient use of existing generating and transmission assets, reliability improvements, system upgrade deferral and, importantly, cost savings for ratepayers[113].

i. Existing Examples

Like dynamic line rating, storage as transmission has already been used in international contexts to defer expensive immediate transmission grid upgrades. For instance, the first phase of Germany's 1300 MW NetzBooster energy storage project is set to be completed in 2025 with 450 MWs of storage serving as backup transmission capacity in place of a new contingency relief transmission line[114]. During normal conditions batteries charge, making use of transmission lines during periods of low demand. In contingency situations or in the event of a grid failure, the storage "will intervene … to inject or absorb power into the line to which it is connected and will mimic power flow on transmission lines, enabling time for grid operators to redispatch generation."[115]

In 2018, the Midcontinent Independent System Operator (MISO) authorized energy storage projects' eligibility for cost recovery under its transmission expansion plan, like traditional transmission projects[116]. This paved the way for the Waupuca Storage as Transmission project that deployed 14 MVAR capacitors[117] and 2.5 MWs of battery storage to improve load-serving reliability on a 115/138 kV transmission line in northern Wisconsin. The Waupaca Energy storage project delivered the same reliability services for $8.1 million in capital expenditure, a 30% discount versus the alternative of adding an additional 115kV circuit for $11.3 million, without needing to expand the existing right-of-way[118].

ii. Recommendations

ECAM notes that PNM and the Brattle Group already identified the local value of energy storage as transmission to be $22 per kW – year in 2019 dollars[119]. Yet transmission upgrades identified in PNM's 2023 IRP do not provide insight to potential storage alternatives that could yield equivalent transfer capability upside at a reduced cost. With FERC's 2023 approval of the Southwest Power Pool's storage as a transmission asset tariff, ECAM believes storage solutions that defer costly system upgrades in New Mexico are potential alternatives to some transmission upgrades and should be included in utility IRPs. Carbon pricing and clean peak standards are additional ways to incentivize utility storage adoption and warrant consideration from the New Mexico legislature. Finally, integrated system planning that considers interactions

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[113] Brown et. al. (2023). "Storage as Transmission Asset Market Study: White Paper on the Value and Opportunity for Storage as Transmission Asset in New York." Quanta Technology. New York Battery and Energy Storage Technology Consortium. Pg. 3
[114] Brown et. al. (2023). "Storage as Transmission Asset Market Study: White Paper on the Value and Opportunity for Storage as Transmission Asset in New York." Quanta Technology. New York Battery and Energy Storage Technology Consortium. Pg. 8
[115] Ibid.
[116] Johanning et. al. (2020). "Energy Storage as a Transmission Asset in MISO". American Transmission Company. MIPSYCON 2020.
[117] An energy storage device that improves power quality and power factor.
[118] Johanning et. al. (2020). "Energy Storage as a Transmission Asset in MISO". American Transmission Company. MIPSYCON 2020.
[119] Hledik et. al. (2019). "The Value of Energy Storage to the PNM System". The Brattle Group. PNM.

between the components of the bulk power system could spur utilities to consider the full value stack storage has to offer as a generation and transmission asset.

c. Other Grid-Enhancing Technologies

Grid operators are limited in their ability to control the flow of electricity when necessary (such as line overload situations) because the flow of electrons through a circuit is governed by network impedance[120]. This results in curtailment during congestion scenarios. Power Flow Controllers (PFC) and grid topology optimization software are additional grid-enhancing technologies that can improve grid operators' ability to control the flow of power and visibility of optimal power routing on the transmission grid[121].

Topology optimization software rapidly solves complicated optimization problems to determine grid scenario reconfigurations in the event of congested or overloaded transmission infrastructure. These solutions can then be carried out using high voltage circuit breakers or by deploying power flow controllers (such as series reactors or phase shifting transformers) that increase impedance on the congested lines spurring electrons to flow along the optimal grid configuration determined by the topology optimization software[122]. These options are often cheaper than reconductoring or rebuilding congested lines yielding capex deferral benefits[123].

Topology optimization and power flow control can also unlock sizeable production cost savings from reduced curtailment when combined with dynamic line rating. Modeling from the Brattle Group found that a potential $90 million investment DLR, PFC, and topology optimization on the Southwest Power Pool's transmission system could yield $175 million in annual production cost savings and a reduce SPP's carbon footprint by 3 million tons annually, thanks to an additional 2,670 MWs of renewable generating capacity interconnected[124]. ECAM urges New Mexico's IOUs to explore pilot programs that make use of new grid enhancing technologies that may expedite the interconnection of renewable energy and promote affordability for ratepayers in the state.

IV. Aligning utility incentives with the energy transition goals

While the preceding sections (II-III) identify grid modernization solutions that synchronize the goals of the energy transition through achieved efficiencies in asset utilization, regulatory changes must also be undertaken to facilitate utility buy-in. Investor-owned electric utilities (IOUs) in New Mexico are granted service territory monopolies subject to regulation by the New Mexico Public Regulatory Commission (PRC)[125]. The PRC is tasked with ensuring that utilities

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[120] The opposition of AC current presented by the combined effect of resistance and reactance in a circuit.
[121] U.S. Department of Energy. (2022). "Grid-Enhancing Technologies: A Case Study on Ratepayer Impact". Pg. 7-8.
[122] Ibid.
[123] Ibid.
[124] Tsuchida et. al. (2021). "Unlocking the Queue with Grid-Enhancing Technologies: a case study of the Southwest Power Pool". The Brattle Group. SPP.
[125] NMSA 1978 § 62-3-1 et seq

provide “adequate and reliable” electricity service to customers at “fair, just, and reasonable rates.”[126] This amounts to a cost-of-service regulatory structure whereby the PRC approves volumetric electric rates according to a utility’s identified cost of providing electricity to end users. Approved rates allow the utility to recoup its investments, recover operating costs, and generate a return on equity (ROE) for its shareholders through electricity sales[127]. This framework sets up incentive structures that are not aligned with efficient asset utilization at New Mexico’s IOUs.

First, in linking utility revenue to volumetric electricity sales, utilities are disincentivized from promoting and investing in energy efficiency, distributed generation, and behind-the-meter (BTM) storage. Second, the rate of return earned on capital expenditures incentivizes utilities to favor high value infrastructure projects at the expense of potentially cheaper non-wires alternatives, grid enhancing technologies, or distributed generation and storage. Below are several regulatory changes that would incentivize greater system efficiency for an affordable, reliable energy transition.

a. Revenue Decoupling

Amendments to the Efficient Use of Energy Act (EUEA) passed in the 2019 legislative session attempt to address the problematic link between utility revenue and electricity sales by allowing utilities or the PRC to file motions to decouple electricity revenues from volumetric sales.[128] A 2024 New Mexico Supreme Court opinion clarified that the statute describes a rate adjustment mechanism allowing utilities to recover the full amount of revenue approved by the PRC regardless of the quantity of electricity sold[129]. Combining this decision with language in the EUEA, New Mexico’s energy efficiency statute legalizes a mechanism that functions as a tariff rider by raising or lowering electricity rates to ensure the utility collects the full amount of revenue approved by the PRC[130]. Since the 2024 Supreme Court decision, no utility has filed a motion for revenue decoupling.

ECAM views the adoption of rate adjustment mechanisms that decouple utility revenue from sales as necessary for achieving New Mexico’s ambitious decarbonization goals while maintaining affordability. As shown above, the key to an affordable energy transition lies in more efficient use of existing energy infrastructure. At the core of these efficiencies is peak demand reduction which can be achieved through energy efficiency measures and demand response as well as distributed generation and storage. Revenue decoupling will help align the interests of New Mexico’s investor-owned utilities with energy efficiency and demand-side management, making them neutral beyond the five percent energy savings currently mandated in the state.[131]

[126] Ibid.
[127] NMAC 17.9.530
[128] NMSA 1978 § 62-17-5 F
[129] Coal. for Clean Affordable Energy v. NMPRC, 2024-NMSC-016
[130] NMSA 1978 § 62-17-5 F
[131] NMSA 1978 § 62-17-5 G

b. Performance-Based Regulation

While revenue decoupling removes utilities' incentive to increase electricity sales, it does not address utility bias for capital expenditure. Utilities are entitled to PRC-approved returns on their capital assets after accounting for depreciation known as return on equity[132]. Information asymmetry between the utility and the regulator regarding the complexities of the electricity grid leads to adverse selection in the regulator's determination of utility revenue requirements.[133]

For example, under cost-of-service regulation, a utility planning to increase transmission capacity to serve load growth may favor expensive new or reconductored transmission lines while downplaying the efficacy of grid enhancing technologies (such as dynamic line rating) that better serve ratepayers' affordability interests in PRC filings[134]. This bias for capital expenditure exacerbates inefficient asset utilization at New Mexico's IOUs. To address this issue, the state's regulatory framework should be modified to facilitate utility decision-making that prioritizes affordability without sacrificing reliability. Regulators in New Mexico can follow examples from other jurisdictions that combine revenue decoupling with multiyear rate plans and performance incentive metrics to better align utility interests with the goals of the energy transition.

i. Multiyear rate plans

Rate cases in New Mexico are typically filed on an ad hoc basis that does not prioritize cost control. Utilities can file new cases for rate adjustment whenever they need to recover costs. Under this framework, the frequency of rate cases is likely to increase in the coming years due to accelerating electricity demand growth and associated investments[135]. A multiyear rate plan (MRP) sets rates for a defined period of years, effectively placing a moratorium on rate cases during that time, incentivizing utilities to control costs throughout the duration of the plan.[136] Forecasted revenues for the years covered by the plan are automatically scaled up or down to account for exogenous costs and to immediately return portions of utility savings to customers using attrition relief mechanisms[137]. Hawaii's performance-based regulatory framework is one example of how other states are leveraging MRPs to serve ratepayers' affordability interests. The Hawaii PUC determines a baseline revenue requirement for Hawaiian Electric and adjusts the requirement annually for the intervening five years between rate cases using the following formula:

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[132] NMAC 17.9.530

[133] Joskow, P. (2024). The Expansion of Incentive (Performance-Based) Regulation of Electricity Distribution and Transmission in the United States. Review of Industrial Organization. 1-49.

[134] U.S. Department of Energy. (2022). Grid-Enhancing Technologies: A Case Study on Ratepayer Impact. 8. Adoption Challenges.

[135] Joskow, P. (2024). The Expansion of Incentive (Performance-Based) Regulation of Electricity Distribution and Transmission in the United States. Review of Industrial Organization. 16.

[136] Whited and Roberto. (2019). Multi-Year Rate Plans: Core Elements and Case Studies. Synapse Energy Economics.

[137] Ibid.

Annual Revenue Adjustment = (Inflation – Productivity) + (Exogenous Events – Customer Dividend)[138]

Since the late 1980s, jurisdictions[139] across North America have implemented MRPs to limit utility spending[140]. A 2017 Berkeley National Lab historical analysis of these plans found that general periods of increased rate case frequency were correlated with reduced productivity in the utility sector[141]. More detailed analysis of individual utility performance compared to the broader U.S. utility sector led the researchers to conclude:

> "… MRPs (and, more generally, infrequent rate cases) can materially improve utility cost performance… [Efficiency] growth of investor-owned electric utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the U.S. electric utility norm. Stronger incentives produced cost savings of 3 percent to 10 percent after 10 years."[142]

In addition to cost control through reduced rate case frequency, MRPs can be paired with efficiency carryover mechanisms (ECMs) to address utility capex bias. Under MRPs, utilities' incentive to control costs diminishes as a new rate case approaches. ECMs address this by allowing efficiency savings achieved in one period to be rolled over into the new rate period[143]. Since operational expenditures (such as energy efficiency and non-wires alternatives) often deliver more attractive long-term savings versus capex, ECMs can equalize the incentives between capex and opex, encouraging utilities to pursue the most cost-effective solutions regardless of expenditure class[144].

ii. Performance Incentive Metrics

Regulators can leverage performance incentive metrics (PIMs) to complement the cost control impacts of multiyear rate plans and incentivize utilities to achieve other goals such as service quality improvement. Performance Incentive Metrics (PIMs) motivate utilities to take actions they otherwise would not attempt by connecting a portion of their compensation to achievement of predetermined goals[145]. As of 2024, 14 states use PIMs to regulate electric or gas utilities [146].

Shared savings/ net benefits mechanisms are one type of PIM that can reduce capex bias by allowing utilities to financially benefit from a portion of the savings achieved through improved energy efficiency or deploying non-wires

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[138] Hawaii Public Utilities Commission Docket 2018 - 0088, Proposed Final Tariffs 2021 .
[139] See Central Maine Power, MidAmerican Energy, Ontario Electric Utilities, California Electric Utilities, New York Electric Utilities.
[140]Deason J. et al. (2017). State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities. Lawrence Berkeley National Lab.
[141] Ibid.
[142] Ibid.
[143] Rebane et. al. (2022). Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States. RMI.
[144] Brown and Zarakas. (2019). Improving the PBR Framework in Hawaii: Addressing the Risk of Capex Bias. The Brattle Group.
[145] Goldenberg, Cross-Call, Billimoria, and Tully. (2020). PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals, Rocky Mountain Institute.
[146] RMI Performance Incentive Metrics Database. (2024).

alternatives and grid enhancing technologies[147]. In 2024, Colorado's PUC authorized the use of a shared net benefit mechanism that compensates Xcel Colorado at 8% of energy savings' net benefit value after achieving 80% of its yearly energy savings goal[148]. The compensation rate increases by 50 basis points for each additional 5% increase in gigawatt hours of energy saved up to 125% of the utility's energy efficiency goal[149]. Total performance incentive benefits for gas and electricity utilities are capped at $18 million for 2024, $22 million for 2025, and $25 million for 2026[150].

Regulators can also devise PIMs to achieve other outcomes such as service quality improvements or better asset utilization. Various jurisdictions across the U.S. already regulate utilities with fixed amount or ROE adjustment PIM incentives designed to reduce DER interconnection times, increase desirable AMI usage, and utilize demand flexibility to defer grid upgrades among other goals. Under Hawaii's Interconnection PIM, Hawaiian Electric can earn a yearly bonus of up to $1,050,000 by reducing average DER interconnection time to meet targets set by the PUC[151]. The utility is also fined up to $315,000 per year if the average interconnection time increases beyond certain thresholds[152]. New York's Locational System Relief Value Load Factor PIM aligns shareholder interests with more efficient asset utilization by raising National Grid's ROE by 1 to 5 basis points for increasing the load factor of 4 to 7 congested substations per year[153].

iii. ECAM Position

Without modifications to the state's cost of service regulatory framework, utility bias for capital expenditure is likely to hinder an affordable energy transition in New Mexico. ECAM sees performance-based regulation as one way to align utility incentives with the goals of the energy transition. The policies presented above are provided as example points of reference and concepts that should be part of the energy regulation discussion in New Mexico. The PRC should convene workshops with industry stakeholders in the coming years to devise an implementation strategy for multiyear rate plans at New Mexico's IOUs. These workshops should also include consumer advocates and consider performance incentive mechanisms that are tailored to achieve outcomes in the interests of New Mexico's ratepayers.

Conclusion

Energy grid planning, policy, and regulation in New Mexico will have to leverage innovative technologies, animate new markets, and rethink outdated incentive structures to address mounting affordability concerns on the grid. Managing load growth while pivoting New Mexico's energy system towards renewable generation will require large amounts of public and private spending, and current supply constraints for key components only complicate matters.

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[147] Littell. D. et al. (2018). Next-Generation Performance-Based Regulation Volume II: Primer – Essential Elements of Design and Implementation. National Renewable Energy Laboratory (NREL). Regulatory Assistance Project (RAP).
[148] Colorado Public Utility Commission Docket # 22A-030EG Commission Decision, ¶ 254.
[149] Ibid.
[150] Colorado Public Utility Commission Docket # 22A-030EG Commission Decision, ¶ 267.
[151] Hawaii Public Utility Commission Docket # 2018-0088 Decision and Order # 37787. Interconnection Approval PIM.
[152] Ibid.
[153] New York Department of Public Service cases 20-E-0380 and 20-G-0381 Appendix 7 Table 1 System Efficiency EAMs

ECAM views grid modernization as one approach to achieving a more affordable energy transition without sacrificing reliability. With changes to the current regulatory framework, new technology can be deployed to achieve greater efficiency in the utilization of grid assets that have already been amortized. By using existing infrastructure more efficiently, utilities can defer immediate upgrades and grid expansion to better prioritize investments in the new capital assets that are most needed. These technologies can also support greater visibility and understanding of the existing grid, enabling infrastructure owners to operate their systems more safely and reliably.

In the context of system-wide efficiencies, grid modernization also highlights the importance of leveraging holistic linkages between the three sectors of the bulk power system (distribution, transmission, and generation). As shown above, decisions made on the distribution grid can potentially reduce the need for additional transmission capacity or generation resources and vice versa. As more distributed resources are integrated into New Mexico's low-voltage systems, and decarbonization goals drive the demand for increased transmission and generation capacity, utilities, regulators, and state agencies should continue to explore the intersections and interactions between these sectors to develop the most cost-effective solutions for grid expansion.

By modernizing the grid, utilizing existing infrastructure more efficiently, and assessing the needs of the energy system holistically, New Mexico can manage load growth and decarbonization goals while maintaining a reliable and affordable energy system for the ratepayers who depend on it.