PREPARED BY GDS ASSOCIATES, INC.

Los Alamos County

Electric Cost of Service and Rate Study

May 1, 2024

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

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1 Executive Summary

In February 2023, Los Alamos County (referred to herein as "LAC" or "the County") engaged GDS Associates, Inc. ("GDS") to conduct an electric rate study and cost of service study. A rate study examines the current financial condition of a utility, along with the utility's expected levels of expenditures, to determine the magnitude and timing of future rate increases. A cost of service study reviews the current cost of providing services to members of each rate class and is used to guide rate design. In addition to these tasks, GDS was asked to:

- Provide an opinion of future rate structures that the utility may implement to better align cost causation and recovery.
- Review the effect that debt issuances have on future financial performance and rates. GDS has made recommendations on the potential implementation of demand and time-variable rates.
- Discuss the subsidy, if any, being provided to customers with solar or other distributed energy sources and recommend steps the County should take to remedy that subsidy.

Budgeted costs for Fiscal Year 2024, with adjustments, were used as the basis for the study, including power-related costs that are expected to be incurred at the Electric Production Department and passed through to the Electric Distribution Department, as forecast by LAC staff. These power-related costs make up a large portion of the total cost of service, and fluctuations in power costs may cause changes in the cost to serve rate classes. GDS has not assessed what effect, if any, changes in currently anticipated Fiscal Year 2025 costs would have on the results of our study.

Most of our recommendations cannot be implemented until several years in the future when LAC has a more capable billing system. However, we highlight two of our recommendations which could potentially be implemented within a short period and that we believe will have a beneficial impact on the utility.

The first of these recommendations is that the utility should implement some form of power cost recovery mechanism. In short, we believe that the practice of collecting all of generation and purchased power, which make up around 50% of the cost of serving customers through "base" rates, both introduces a high level of uncertainty into any forecast of future financial health or performance and produces friction by necessitating any adjustment in revenues be produced through a change to base rates. Our recommendation is that LAC introduce a pass-through mechanism that is adjusted up or down based on a determination of need by the Board of Public Utilities ("BPU") or City Council, rather than one that automatically recovers any change in the cost of power. An additional benefit to enacting a pass-through mechanism would be that it would eliminate the need for a Rate Stabilization Reserve, allowing the County to more quickly achieve the goal of fully funding reserves and freeing capital for other purposes.

The second recommendation that can be implemented in the short term relates to the billing mechanism that is used for customers who own distributed energy resources. The current approach, referred to as a net metering arrangement, compensates a portion of the generation produced by the distributed energy resource at the full retail volumetric rate. As the retail volumetric rate is significantly higher than the cost of power from other generation resources, this results in a substantial subsidy to these customers. GDS recommends that a net billing arrangement, in which the netting calculation is done "on the bill," be adopted to allow LAC more control over the amount of subsidy that is provided to these customers. We also recommend that the overall approach to distributed energy customers be developed at a strategic level, taking into consideration LAC's overall policy goals and targets.

1.1 Rate Study Results

Assuming the energy costs forecast at the beginning of Fiscal Year 2024 are accurate, GDS expects the rate increase that will be effective July 2024 to provide adequate revenue to operate the system and provide the target 1.6 debt service coverage ratio through the end of Fiscal Year 2027. In Fiscal Years 2028 and 2029, a higher level of revenue needs is anticipated and increases in rates of around 5.4% and 10%, respectively, will be required to maintain a 1.6 debt service coverage ratio. The driving force behind the increases in the later years of the study is anticipated changes in the cost of power.

Table 1 - Rate Study Results

Description	FY24	FY25	FY26	FY27	FY28	FY29
O&M and A&G	$ 5,200,104	$ 5,386,894	$ 5,580,832	$ 5,782,196	$ 5,991,278	$ 6,208,379
Purchased Power	9,516,802	8,131,600	7,567,427	6,806,886	7,388,937	8,693,960
Capital-Related	1,185,974	1,367,219	1,660,825	2,576,890	2,930,828	3,236,599
Transfers and Reserves	1,140,745	1,152,059	1,169,309	1,186,847	1,204,677	1,222,804
Total	**17,043,624**	**16,037,772**	**15,978,393**	**16,352,819**	**17,515,720**	**19,361,743**
Recommended Base Rate Increase	**9.0%**	**9.0%**	**0.0%**	**0.0%**	**5.4%**	**10.0%**

1.1.1 Critical Matters

- The overall cost of running the utility – and therefore the amount of revenues that must be collected from customers – is highly dependent on the amount of power expense that is transferred from the Electric Production Department. GDS has relied on the internal LAC forecast for these costs produced for the Fiscal Year 2024 budgeting process. Electric Production costs are expected to decrease significantly in Fiscal Year 2025 due to the inclusion of one-time planned maintenance in Fiscal Year 2024 expenses.
- No additional funding to meet financial targets or to replenish reserves has been included in the forecast of costs, beyond the cash provided by the County's target 1.6 debt service coverage ratio in Fiscal Years 2025 through 2029. These excess revenues can be used to replenish reserve balances or to reduce reliance on debt issuances for capital projects. A discussion of the impact the use of debt funding has on rates and the ability of proposed rates to achieve the county's policy goals for reserve balances can be found in Sections 7 and 8, respectively.

1.1.2 Recommendations

- We recommend that LAC track the results of this study against actual results through Fiscal Year 2027 with the goal of assessing if an increase is required in Fiscal Year 2028.
- If the level of increase required in Fiscal Year 2028 shown above is accurate, the increase can either be achieved by implementing a 5.5% increase in Fiscal Year 2028 and a 10% increase in Fiscal Year 2029, or through two 8% increases.
- When the need for an increase is being assessed, we believe that two essential metrics that should be reviewed are (1) whether rates are anticipated to achieve the 1.6 debt service coverage ratio target set by the County, and (2) the progress that the County has made towards achieving fully funded reserves by Fiscal Year 2034.

1.2 Cost of Service Results

The Cost-of-Service Study ("COSS") shows that rates being collected from customer classes are generally appropriate and in line with cost causation. While subsidies exist, they do not rise to the level that we believe necessitates immediate action and can be corrected the next time the County chooses to adjust rates or change the recovery structure. Levelized revenues represent the over/(under) recovery of costs that would exist if all rates were adjusted pro rata so that the cost of service was recovered on a utility-wide basis.

Table 2 - COSS Results

	Cost of Service (FY25)	Revenues (July 2024)	Under/(Over) Recovery		Under/(Over) Recovery Levelized	
			$	%	$	%
Residential	$ 9,983,941	$ 9,649,795	$ (334,146)	-3%	$ (1,057,883)	-11%
Small Commercial	1,475,442	1,985,079	509,637	35%	360,756	24%
Large Commercial	2,310,456	3,080,877	770,421	33%	539,354	23%
County	1,501,778	1,821,455	319,676	21%	183,067	12%
School	546,738	590,353	43,615	8%	(662)	0%
Area Lighting	39,749	16,343	(23,406)	-59%	(24,632)	-62%
Total	**$ 15,858,105**	**$ 17,143,903**	**$ 1,285,798**	**8%**	**$ -**	**0%**

1.2.1 Critical Matters

- A COSS is a tool that provides an indication of potential subsidies occurring on the system. The results of the COSS will differ from period to period and must be evaluated in conjunction with policy and other ratemaking considerations when determining what rates to charge.
- It is important to recognize that inter- and intra-class subsidies between customers will exist in any system that serves more than one customer. Each individual service location requires a different amount of investment to serve it and has different usage characteristics that change over time. Even when subsidization can be eliminated, it may not be appropriate due to competing concerns of ratemaking. For instance, if variable charges were reduced to the cost of power, the economic incentive to conserve energy would be reduced.
- It is common in municipal rate design for residential customers to pay rates that under-recover the cost of serving that class, both for policy reasons and because of reluctance to increase residential charges.
- Power-related costs make up a large portion of the total cost of service. Fluctuations in power costs may cause changes in the cost to serve rate classes.
- Due to the internal allocation of demand-related costs within the resource pool, GDS determined that a departure from the industry standard allocation methodology was appropriate. This change in methodology resulted in a lower allocation of costs to the residential rate class, with most of the increase assigned to the Large Commercial, Large County, and Large School customers. The effect of this decision on cost allocation is quantified in Section 9.4.1.
- The findings at the individual class level, including discussion of subsidization occurring within the residential rate class, and comparison of fixed costs and recoveries can be found in the rate recommendations below.

1.3 Rate Recommendations

1.3.1 Current Rates

LAC's current rate structure is easy to understand, easy to bill, and can be easily modified to fairly apportion costs to the correct customers. While changes could be made to the overall rate structure, such as implementation of demand rates, the benefits resulting from those structural changes may not be worth the additional administrative and billing overhead, and the County should take these factors into consideration when contemplating changes.

1.3.1.1 Critical Matters

- Current service charges for residential customers are significantly below the fixed costs of service. Subsidized service charges are typical as they allow customers to have more control over their bills by reducing usage and reduce bills for lower or fixed income customers.
- Small Commercial, Small County and Small School customers are over-recovering their cost of service. At a high level, subsidies paid by Small County and Small School ratepayers are offset by lower subsidies received by the respective Large rate classes, which reduces the level of concern.
- Area lighting rates do not recover the cost of service of the class.

1.3.1.2 Recommendations

- No subsidies exist that rise to the level that we would consider atypical or to be cause for immediate concern. Our recommendations regarding rate recovery below can be implemented at the time of the next overall rate increase or in conjunction with another rate structure, such as demand rates or time-variable rates.
- A small proportional increase in revenues collected through Residential service charges should be considered when rates are next increased. An increase to $14 would eliminate some of the subsidies extended to lower usage customers without significant impacts to bills and would move LAC's fixed charges closer to those charged by nearby utilities.
- We recommend that the Small Commercial and Small County classes get a smaller increase relative to other classes next time the County adjusts rates. We recommend that this be achieved through relative reductions to variable charges, potentially to the extent of maintaining current charges.
- While area lighting rates appear to need a significant increase, we recommend that they continue to be adjusted generally in line with increases achieved for the entire utility. This recommendation is made in consideration of the relatively small revenue requirement associated with this class and the fact that area lights are generally collocated with a main service location.[1] We do however recommend that costs associated with maintenance and upkeep of area lighting (such as switching bulbs or repairs) be collected to the greatest extent possible through separate fees charged directly to the responsible party.

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[1] And therefore, generally require less incremental investment in distribution system than a standalone service location.

1.3.2 Alternative Rate Structures

The implementation of demand or time-variable rates was identified in discussions with LAC staff and the BPU as a potential way of addressing cost subsidies present in the current rate structure. Demand rates are seen as a potential way of reducing subsidies present under the current rate structure and potentially raising revenues in a way that better approximates cost causation without causing undue impacts to lower usage customers, while reducing peak demands experienced at the retail level. Time-of-Use rates incentivize customers to change consumption patterns to avoid times of high energy prices and reduce peak demand levels.

LAC is unique in that it participates in the Resource Pool in conjunction with Los Alamos National Laboratory. While this relationship clearly reduces the cost of power and is beneficial to the utility, the allocation of costs within the Resource Pool dictates the level of cost savings which can ultimately be achieved. In particular, the allocation of energy-related costs monthly based on each participant's actual levels of usage means that the distribution utility is exposed to the average cost per kWh rather than the real-time price, limiting the savings achieved if consumption is shifted to times lower cost energy is available. Timing differences may also occur between when demand is measured for purposes of the Resource Pool and when peak demand occurs on the distribution system.

1.3.2.1 Critical Matters

- The current billing software is unable to bill time-variable rates and new software is not anticipated to be in place for several years.
- Given the limitations of the information provided by the Advanced Metering Infrastructure ("AMI") system, demand values discussed within this report are based on hourly average demands, not the commonly used 15-minute demand measurement period. As a result, the illustrative demand charges presented are not directly comparable to the County's current demand charges for Large Commercial, School, and County customers.
- Alternative rate structures can be adopted as the standard set of rates for all customers, or customers may be given a chance to retain the current rate structure if they prefer it due to simplicity or the customer's inability to avoid bill increases under the new structure. If the move to the alternative rate structure is optional, it may be done on an "opt-out" or "opt-in" basis.
- If the utility determines that time-variable rates should be implemented in the future, attention should be paid to the coincidence of demand experienced distribution system level and demand used for Resource Pool allocations. This is necessary to ensure that the County avoids inadvertently increasing costs when focused on reducing distribution system peaks.

1.3.2.2 Recommendations

- Targeting demand at specific times, rather than trying to limit non-coincident demand peaks at individual locations will bring the largest benefit to the County, exceeding those that would be brought if the County were to implement rates based on individual customers' peak demand.
- Based on current usage patterns, peak demand generally occurs between 5 PM and 11 PM for the retail system. While peak demand levels fluctuate seasonally, we recommend that these hours be utilized for any time-dependent rate on a year-round basis to reinforce these hours in customers' minds.

- We recommend an "opt-out" approach when transitioning customers to a new rate structure. Opt-out structures have been demonstrated to result in larger reductions in peak demand and overall higher customer participation while allowing customers who would be harmed by the alternative structure to continue taking service under the current rates.
- A time-variable rate (which could be either demand or usage-based) would most effectively reduce demands at times of peak load. For this reason, we recommend that the County adopt a time-variable rate rather than a demand rate based on peak usage.
- While both energy-[2] and demand-based time variable rates have will have similar effects, we recommend an energy-based time variable rate as best for the County. This design is easier for customers to understand, is comparable to rates put in place by neighboring utilities and is effective at reducing demand peaks.
- If an energy-based time-variable rate is adopted, an on/off peak pricing ratio of 2:1 or higher will provide adequate incentive for customers to shift usage off peak. Our illustrative rates for Fiscal Year 2025 achieve a 2.5:1 on/off peak pricing ratio.
- If the County adopts demand rates that do not incorporate a time-variable element, we recommend a phase-in of rates to avoid customer confusion. Several utilities have included a "demand rate" with no associated charge on ratepayer bills to accustom them to the idea of seeing a demand charge and understand how it will impact their bill. Another option to educate customers about demand rates is to produce "shadow bills" based on a prospective demand rate, allowing customers to see bill impacts of a demand rate before the rate is in effect. Introduction of any demand rate should be paired with an informational campaign to help customers identify what activities cause their demand to increase.[3]

1.3.3 Distributed Energy Resource Generation Rates

BPU has had several discussions on recommendations from staff and outside consultants on potential subsidization of customers with rooftop solar and other distributed resources (historically referred to by LAC as Distributed Energy Resources, or "DER"), and to how to fairly recover fixed costs from DER customers. BPU policy adopted in 2016 anticipated identifying what type and level (utility-scale, circuit-scale, or distributed) of carbon-free generation brought the most benefits to the utility and proper recognition of how the costs that may be avoided by customers with DER be incorporated into rates paid by those customers. LAC clearly communicates to customers that distributed generation rates and rate structures in place currently are not guaranteed in the future within the application customers must produce for interconnection.

1.3.3.1 Critical Matters

- Based on usage levels before and after installation of DER, the average residential DER customer is being subsidized both within the base rate structure and through the net metering arrangement.

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[2] An energy-based time variable rates would price usage based on whether the usage occurs in "on" or "off" peak periods. A demand-based rate would be based on maximum demand observed in the "on-peak" period.

[3] For example, bill inserts incorporating information pulled from AMI showing demand and identification of days and hours when peaks occur so that customers can identify the underlying causes.

- Subsidization is limited by restrictions on individual DER generation capacity, and generation credit amounts based on LAC's actual wholesale cost of power.
- DER customers bring both qualitative and quantitative benefits to the distribution system, including resiliency, reductions in overall levels of demand, and acting as a green source of energy.
- At a high level, the subsidization of DER occurring in current base rates is relatively immaterial and comingles with other subsidies provided in rates. DER adoption has not reached the point where we believe that a standalone DER rate structure or additional fixed charges would be appropriate.
- The current net metering arrangement prices all produce the highest level of subsidy out of the available generation compensation mechanisms because a portion of generation is compensated at the full retail rate.

1.3.3.2 Recommendations

- Alignment of DER rates with LAC's overall policy goals for DER, green energy, and electrification is essential. While customers may have multiple reasons for DER installation, cost savings or the ability to profit from selling energy to the grid is a primary factor for many customers. Efforts to eliminate subsidization may have deleterious effects on achieving policy goals in other areas, including the level of adoption achieved. We recommend that LAC staff interface with those responsible for implementation of LAC's electrification and carbon neutral targets to develop a comprehensive framework for compensating DER.
- We believe that DER is a good fit for Los Alamos County and that the long-term benefits it can bring, particularly considering potential advances and proliferation of energy storage devices, should not be ignored when the level of subsidy provided to DER is considered.
- DER customers are not treated as an independent rate class, nor are they being treated as members of the class they nominally belong to. We recommend that DER customers remain a member of the class they would otherwise occupy (*e.g.* residential with DER classified as residential), and that the level of subsidization be controlled through the amount being paid for DER generation provided to the system.
- In the case that the number of home battery storage installations increases substantially, the County should consider a stand-alone rate class with higher fixed charges or wire charge, as they have the potential to create significantly higher levels of subsidy than standalone DER.
- We do not currently recommend implementing demand rates or wire charges solely for the purpose of ensuring DER customers pay their cost of service.
- We recommend the adoption of a net billing arrangement. A net billing arrangement has the potential to reduce subsidization of DER customers and, importantly, allows the County more control over the subsidy provided to DER by decoupling DER reimbursement from base rate charges.
- In the future, LAC should consider moving to a rate structure with a time-variable credit paid to DER. Currently DER production begins to taper off in the evening before the system peak occurs, particularly in the winter when days are shorter. A time-variable credit could be used to incentivize installation of batteries or other DER technologies which will be available at times solar is unavailable.

1.4 Other Matters

LAC should consider the implementation of a power cost pass-through mechanism to reduce potential pressure of generation costs on the distribution utility. Such mechanisms are often referred to as a Power Cost Recovery Factor ("PCRF"). We recommend that a pass-through mechanism be adopted for the following reasons:

- A pass-through mechanism requiring BPU approval of any adjustment would allow BPU to continue the same level of control over costs while providing more flexibility to respond to unexpected increases in the cost of power.
- Simplification of the rate setting and financial projection process, as it would allow decoupling of cost recovery of volatile commodity costs and the relatively stable costs incurred at the Electric Distribution department.

2 System Overview

2.1 Electric Utility

2.1.1 Electric Production Department

Since 1985, the County and the U.S. Department of Energy (DOE) have participated in a Resource Pool in which the costs of generation, power purchases, and transmission related to both entities are combined. This Resource Pool is managed by the Electric Production Department and costs are allocated between the participating entities (the County, DOE, and other third parties) monthly according to the Electric Coordination Agreement (ECA). The ECA controls the allocation of costs between the Pool participants based on the underlying fixed or variable nature of the costs and relative demand and energy needs of the participants. Costs allocated to the County are passed directly through to the Electric Distribution Department to be recovered from retail customers and represent between 45% and 50% of costs to be recovered in rates.

2.1.2 Electric Distribution Department

The Electric Distribution Department is responsible for the planning, operation, and maintenance of the distribution system, as well as customer service and billing functions.

2.2 Management and Governance

Los Alamos has a consolidated city-county charter government which allows for the powers of both a municipality and county under the New Mexico Constitution. County utilities are managed by the County's Department of Public Utilities ("DPU"), with a management team consisting of a Utilities Manager and Deputy Utilities Managers for Engineering, Finance and Administrative, Electric Production, Electric Distribution, and the County's gas, water and sewer operations. Management is overseen by two levels of direct governance, the first being the BPU. The BPU is a five-person board appointed by the County Council that holds regular monthly meetings and actively monitors the utility. Ultimate responsibility for the governance of the utilities is provided by the elected County Council consisting of seven members. Partially due to the existence of Los Alamos National Laboratory ("LANL"), the BPU and City Council tend to have a higher level of technical knowledge on factors related to the electric utility than a typical municipal government.

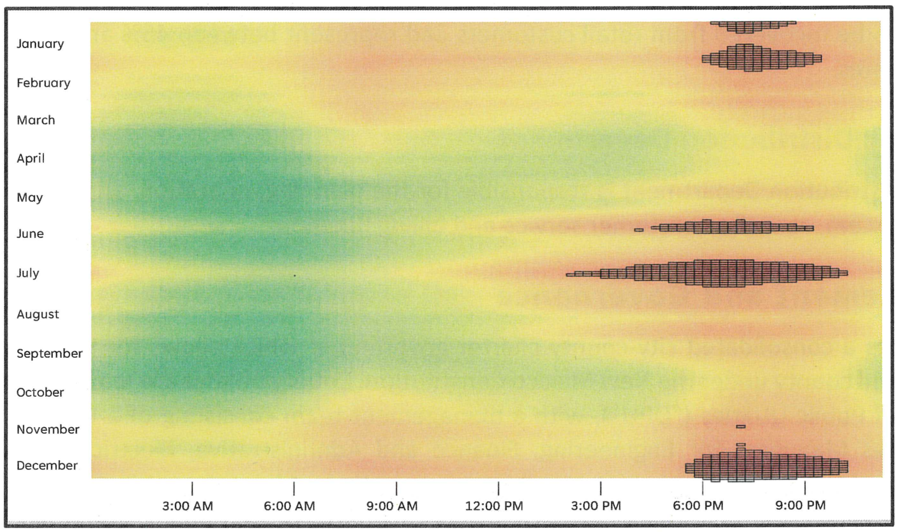
The New Mexico regulatory body responsible for public utilities, the New Mexico Public Regulation Commission, does not have jurisdiction over the rates charged by the County.

3 Utility and Customer Characteristics

3.1 System Load Characteristics

The load generated by the retail system is weather-dependent and can be winter or summer peaking depending on the severity of heat waves or cool fronts each year. AMI information from calendar year 2022 was used to develop weekly averages of load by hour to determine times of peak load, as shown below. The black-bordered areas designate hours in which the system load averages exceeded 75% of the maximum hourly load of the system. The 2022 winter weather was generally average when comparing the three most recent years, with a milder summer than 2021 or 2023.

Figure 1 - Systemwide Retail Load Map



3.1.1 Load Map Interpretation

Load maps presented within this report are developed using LAC's AMI information. The relative amount of load being placed on the system by the customer class or classes being considered is shown as a color scale. Green areas represent low load conditions, while dark orange/red areas represent high load conditions. The progression from the top to the bottom of the chart along the Y axis shows changes through the year and can be used to identify changes in consumption patterns that are due to heating, cooling, and seasonal operations changes. The X axis represents changes that occur throughout the day. The load data illustrated in the heat map was developed using weekly averages for each hour, with data from AMI being cleaned to ensure accurate representation of system load.

Load maps can be used to identify times of high usage, informing cost allocation, appropriateness of specific rate structures, and the approach to time-of-use rates.

3.2 Residential Customer Class

Residential customers make up approximately 90% of the customers on the Los Alamos system and account for around 52% of total kWh sold. Over the last three years, Residential customers have averaged 555 kWh in monthly sales per connection, with the highest consumption occurring in winter months as shown below[4]:

Figure 2 - Residential Average Monthly Consumption per Connection – 2022

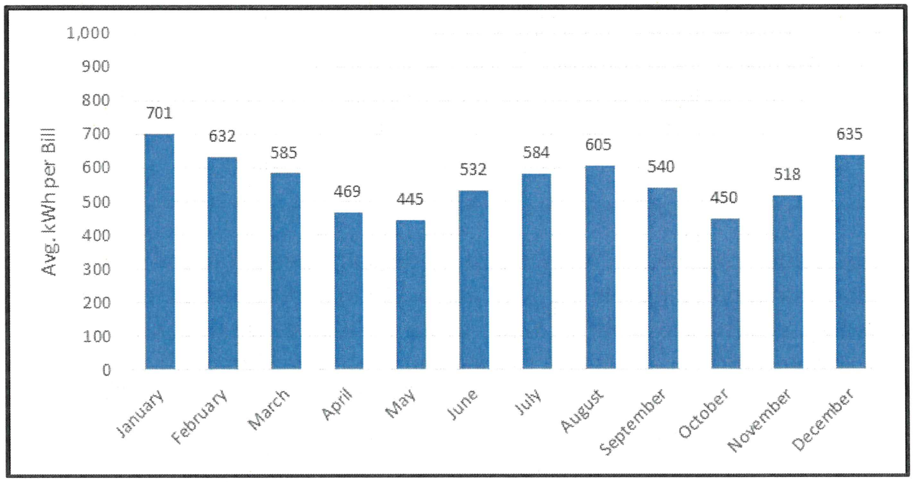
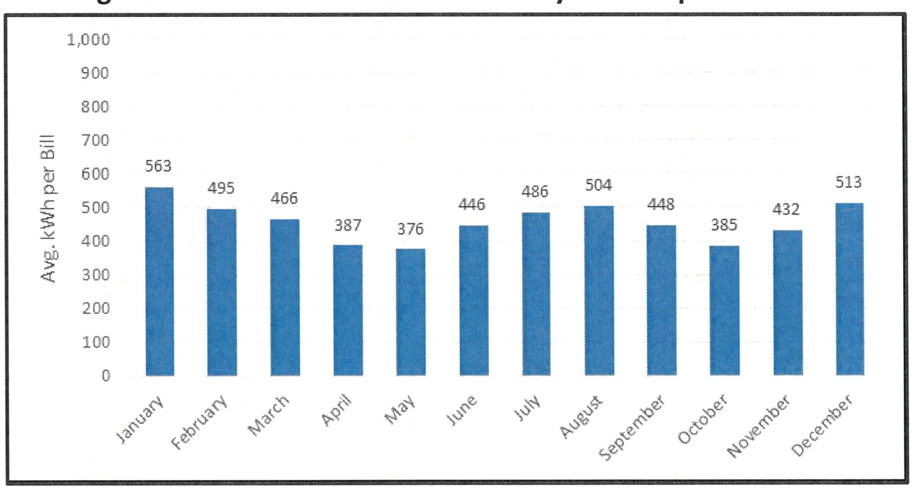


Figure 3 - Residential Median Monthly Consumption – 2022



All locations that serve primarily residential loads (other than some multi-family structures) are grouped into the Residential rate class, with no distinction in classification or rates for different sizes of users. In 2022, the majority of bills fell between 175 and 525 kWh, with the median bill being 453 kWh and the average bill being 559 kWh.

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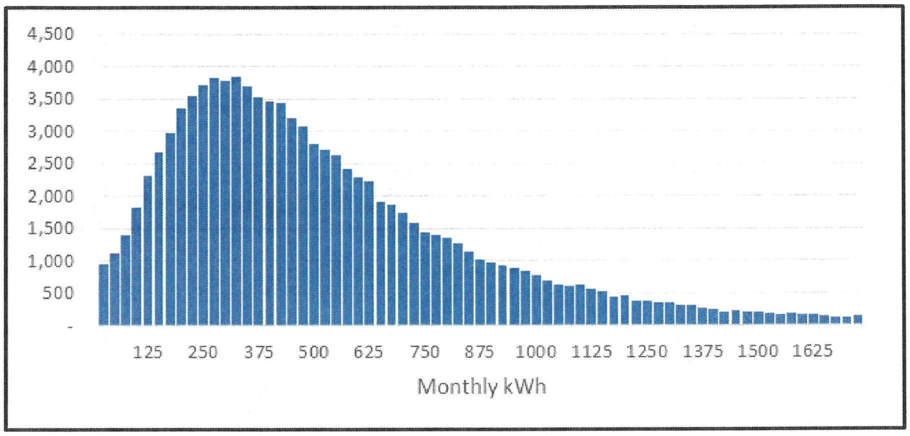
[4] Calendar Year 2022 information shown. A full set of average and median loads for each rate class, along with bill distributions, can be found in Appendix A.

Figure 4 - Distribution of Residential Bills – 2022



The Residential customer class is the main driver of demand peaks on the system. Peak Residential consumption occurs from approximately 8-11 AM and 6-11 PM in response to heating demands and from 1-11 PM when load is driven by cooling. At times of high temperature-driven usage, peak periods may extend into the early morning. On weekends, cooling and heating remain relatively higher throughout the day than on weekdays.

Figure 5 - Residential Load Map – Weekday

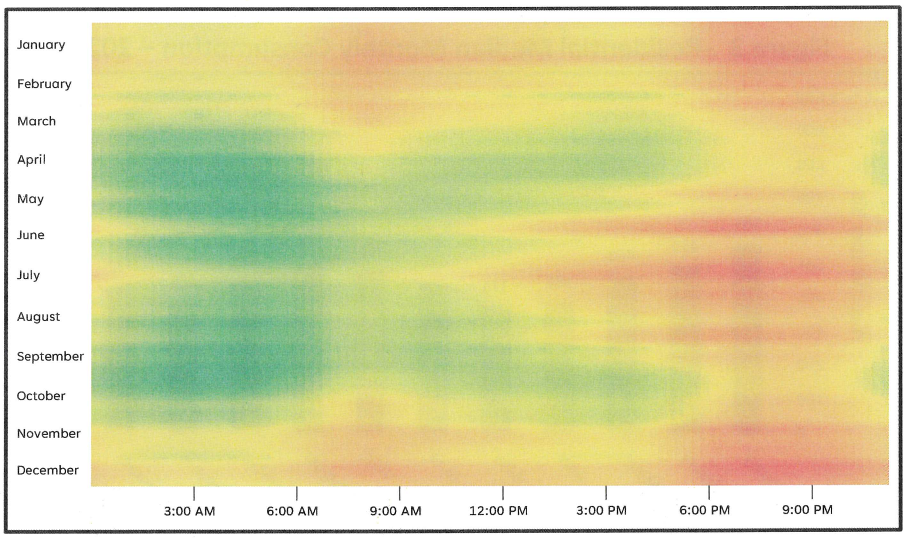
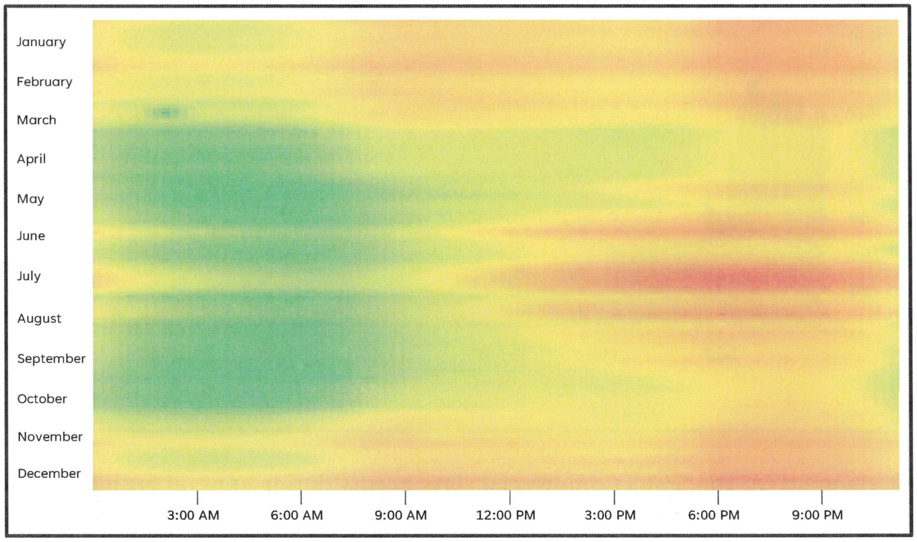


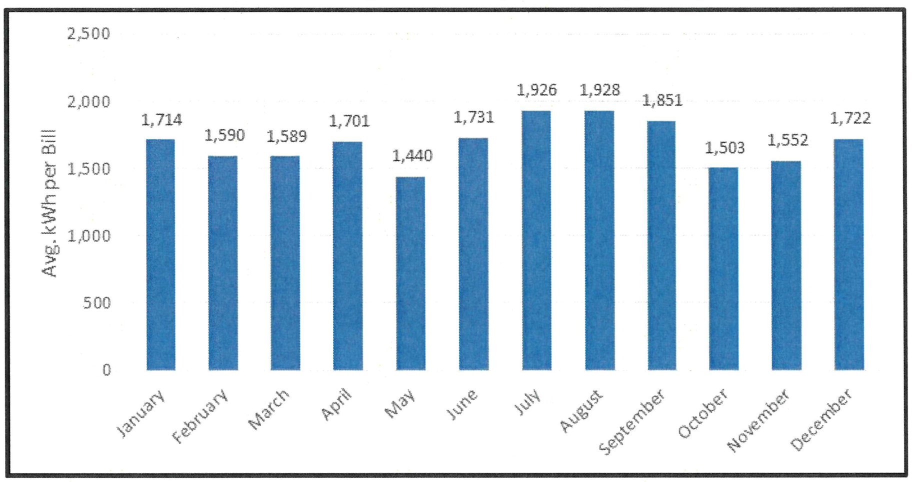
Figure 6 - Residential Load Map – Weekend



3.3 Small Commercial Customer Class

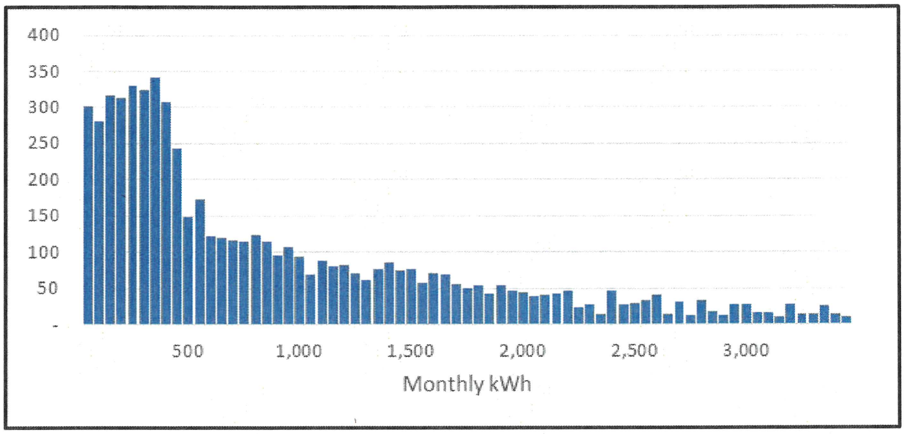
The Small Commercial class is made up of commercial customers with less than 50 kW of demand and make up approximately 6.5% of LAC customers. Small Commercial customers use approximately three times more energy on average than residential customers and have reduced seasonal variability. Unlike residential locations, Small Commercial locations on average usage higher amounts of energy in the summer than winter months.

Figure 7 - Small Commercial Average Monthly Consumption per Connection – 2022



In 2022, Small Commercial customers averaged 1,680 kWh with a median usage level of 619 kWh. Although bills were clustered below the 500 kWh level, a large number of relatively larger users existed.

Figure 8 - Distribution of Small Commercial Bills – 2022



Unsurprisingly, demand for the Small Commercial class occurs during general business hours, starting at around 8 AM and extending through around 5 PM. Like the Residential class, and consistent with the monthly patterns shown above, heating and cooling demands affect the duration and timing of loads on the system. There appears to be less heating load in the Small Commercial class when compared to the Residential class, which explains the higher usage levels seen during the summer months.

Figure 9 - Small Commercial Load Map – Weekday

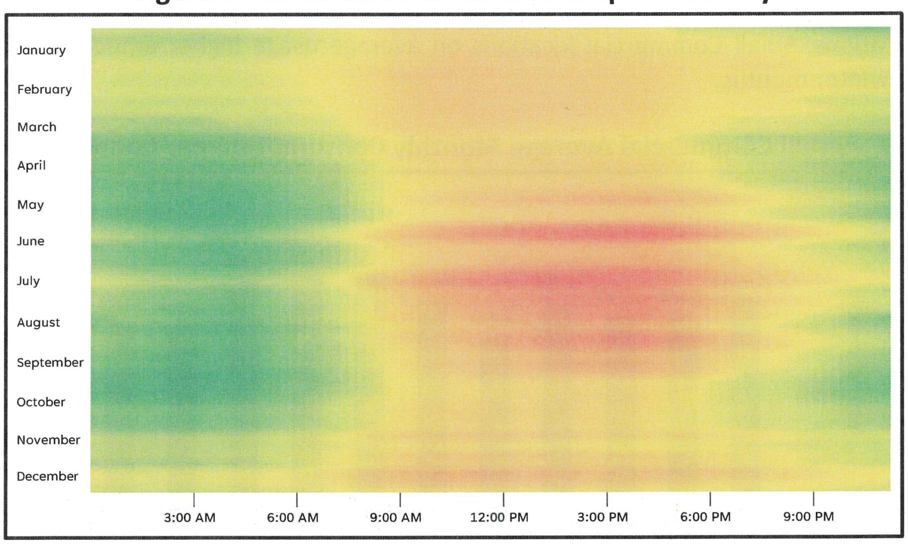
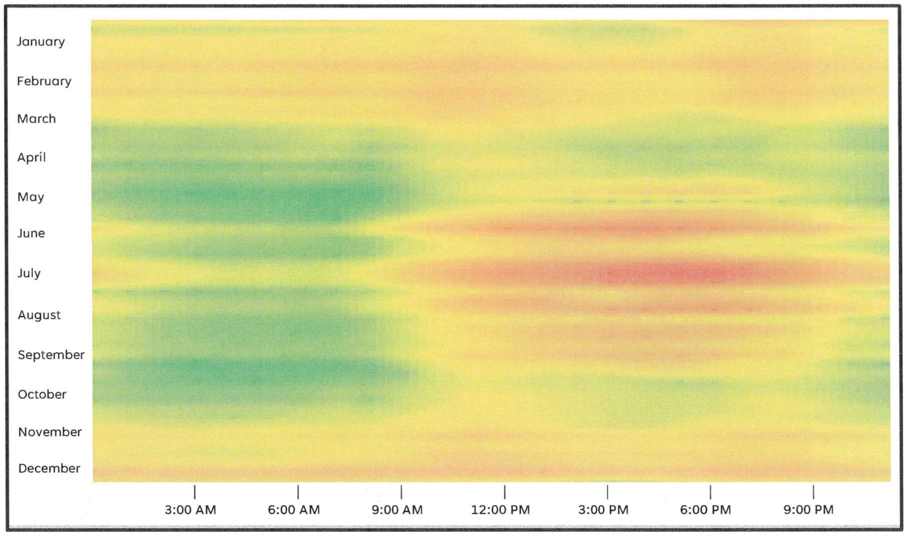


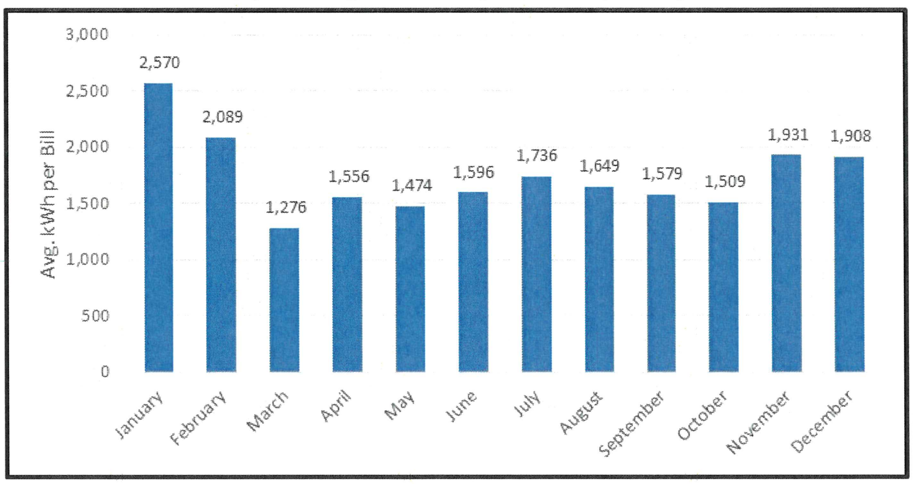
Figure 10 - Small Commercial Load Map – Weekend



3.4 Small County Customer Class

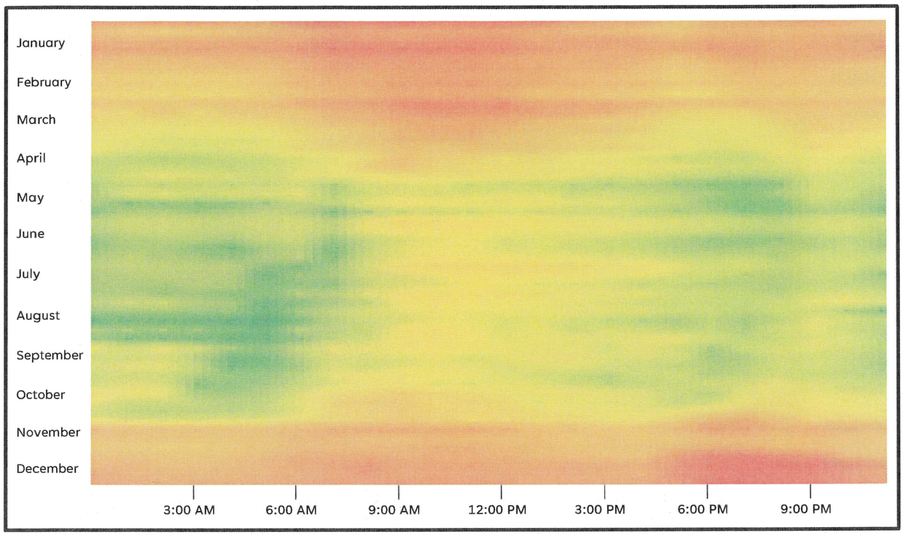
The Small County rate class serves county-owned locations with demand levels under 50 kW. Usage at these locations is high on average at 1,739 kWh per month, however median usage is only 300 kWh. A large number of meters taking service under this tariff are used for irrigation, intermittent usage at parks, sewage lift stations, and other small loads, with fewer constant large loads such as community centers and the airport, leading to the large difference between average and median usage levels.

Figure 11 - Small County Average Monthly Consumption per Connection – 2022



Partially due to the variety of load types billed under this tariff and the number of services dedicated to outdoor locations, less impact is seen from cooling loads during the summer, although loads increase in the winter because of heating or seasonal activities.

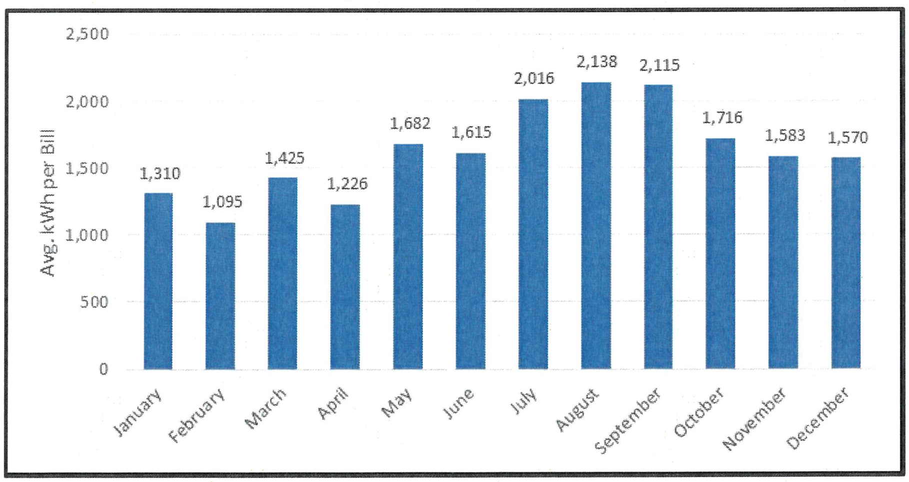
Figure 12 - Small County Load Map – Weekday



3.5 Small School Customer Class

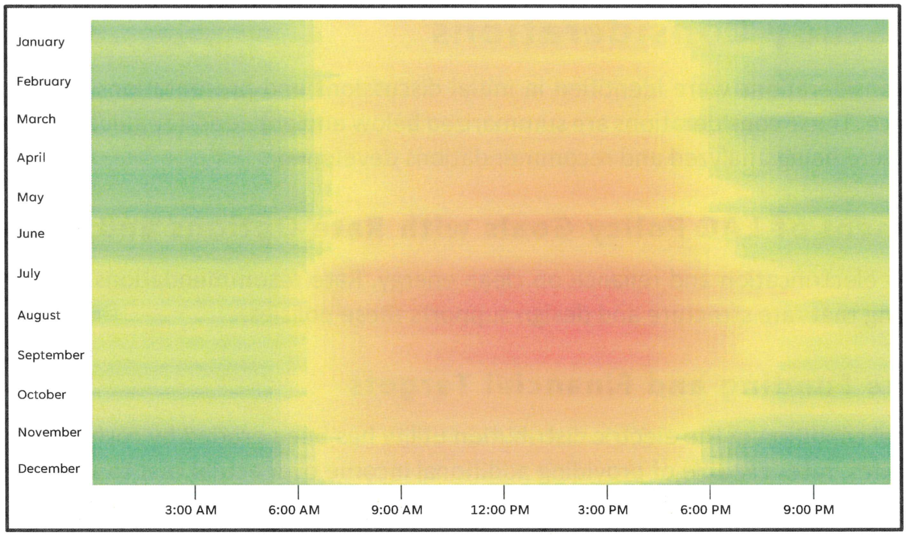
The Small School class is available to educational locations with less than 50 kW of demand. Monthly average usage in 2022 was 1,624 kWh with a median of 839 kWh, and overall the class is more homogeneous than the Small County Rate Class.

Figure 13 - Small School Average Monthly Consumption per Connection – 2022



Much like the small commercial class, Small School loads are driven by the hours in which the facilities are in use, with most of the usage occurring between 6 AM and 5 PM on weekdays. The Small School class shows some response to heating and cooling demands, though less than Residential or Small Commercial customer classes. Over weekends, reactions to cooling and heating loads still exist, but usage is less consistent.

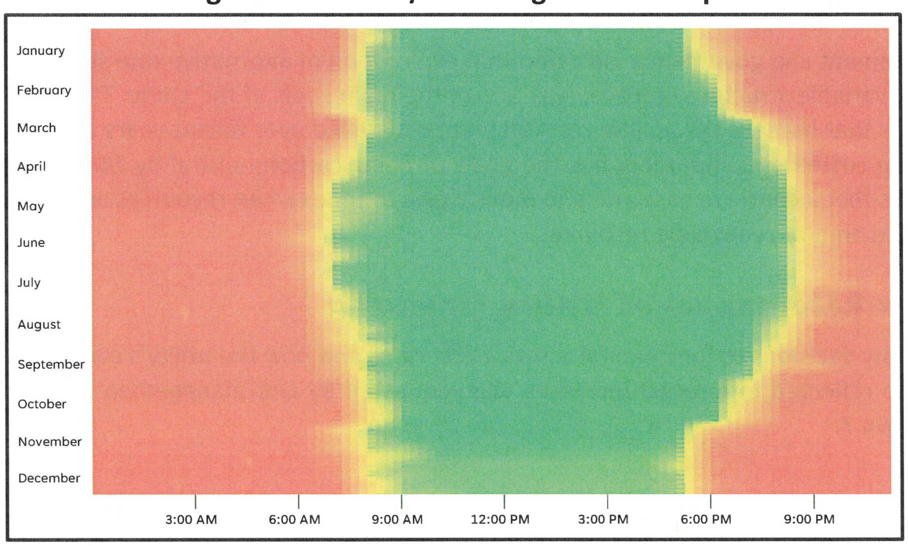
Figure 14 - Small School Load Map – Weekday



3.6 Street/Traffic Lights Customer Class

Metered Street/Traffic Lighting load occurs primarily from dusk to dawn, with load occurring later in the day during the summer when days are longer. No significant differences exist between weekend and weekday usage patterns.

Figure 15 - Street/Traffic Lights Load Map



4 Key Study Considerations

Several key considerations were identified in initial discussions and presentations to LAC management and governance. These considerations are summarized below and provided key guidance when the results of the study were being analyzed and recommendations developed.

4.1 Alignment of LAC Policy Goals with Rate Options and Design

LAC promotes electrification and reliance on clean energy. Rate recommendations were made with the goal of ensuring that rate structure and design supports these policies.

4.2 Reserve Funding and Financial Targets

As the financial condition of the electric distribution utility has been eroded by costs exceeding revenues provided by rates, rates capable of providing additional income over actual cost to service is required.

4.3 Cost-Based Rate Recommendations

Due to the length of time since LAC's last rate study and subsidies present at that time, LAC management expressed interest in identifying the levels of subsidies present on the system and on what approach GDS would take to eliminate them. Specific focus was placed on determining if customers with distributed generation systems were being subsidized by other customers and if so, to what extent. LAC management stated they believed that the current approach was one of the most favorable to distributed generation customers in the nation.

4.4 Exploration of Alternative Rate Structures

Utility management and governance indicated that exploration of alternative rate structures, beyond the current fixed/variable structure in place, was one of the main goals of the study. The utility is interested in rate designs that harness the abilities of AMI meters installed over recent years and better reflect the cost of serving customers. The utility has the goals of being carbon-neutral by 2040 and implementing rate structures that incentivize customers to move usage to times when resources are available or reduce overall reliance on non-renewable resources.

4.5 Review Rate Impact of Utility Financing

A review of how decisions to fund capital assets affect rates and how the utility's current plans to finance assets may be reflected in forecast increases was requested by LAC management. This review can be found in Section 7.

5 Benchmark Utilities

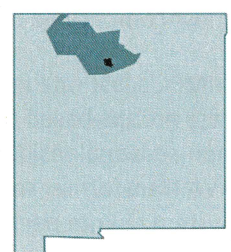
LAC management was asked at the outset of the study to provide a list of comparable utilities which could be used for benchmarking LAC rates. The Los Alamos Charter states that, among other requirements, Los Alamos rates must be comparable to those in neighboring communities.

While comparisons of rates are useful for assessing the overall reasonableness of rate results, customer perception of rates charged by LAC, and regional norms, rate structures and designs will vary from utility to utility based on the extent and location of areas served, ownership structure, customer base, generation resources, and regulatory agency preferences. The population density in areas served by cooperative utilities historically has been much lower than municipal utilities, leading to higher distribution investment on a per customer basis and higher costs of maintenance items such as trimming activities.

A brief description of each benchmark utility is provided below to help gain an understanding of their general characteristics and attributes relative to LAC. All Cooperative rates are under the regulatory purview of the New Mexico Public Regulation Commission ("NMPRC"). In the cases where the Cooperative proposes a rate change and sufficient numbers of members protest the increase, a hearing is held to determine if the increase is reasonable.

5.1 Jemez Mountains Electric Cooperative

Incorporated in 1948 and headquartered in Hernandez, New Mexico, Jemez Mountains Electric Cooperative ("JMEC") serves the areas surrounding LAC in Rio Arriba, Santa Fe, San Juan, McKinley, and Sandoval counties and is a member of the Tri-State Generation and Transmission ("G&T") cooperative. JMEC is the largest electric cooperative in New Mexico and serves approximately 28,000 residential and 3,500 commercial locations.



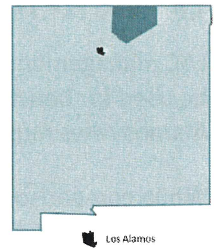
In December of 2022, the NMPRC approved a two-phase rate increase for JMEC customers, the first of which went into effect in January of 2023. Prior to the January 2023 increase, JMEC's most recent rate increase was approved in 2013.

The January 2023 rate increase was necessary as JMEC was in default of its debt obligations in 2022. Rate changes raised overall rate revenue by 9.33% and resulted in a residential facility charge[5] increase from $14 to $18. The second phase of the increase, occurring in February of 2024, raised residential facilities charges to $22, but also decreased volumetric charges correspondingly, resulting in no revenue change at a system level. JMEC justified its move to higher customer charges as better reflecting the underlying nature of its operating expenses, which are primarily fixed in nature. In 2022, the average residential customer of JMEC paid approximately $78.93 per month, or 14.10 cents per kWh.

LAC Staff indicated that JMEC is the most relevant cooperatively owned benchmark considered when performing internal review of rates. JMEC had 113 full-time employees as of December 2022, or approximately 279 ratepayers for each employee.

[5] The fixed component of the bill, comparable to LAC's service charge.

5.2 Kit Carson Electric Cooperative

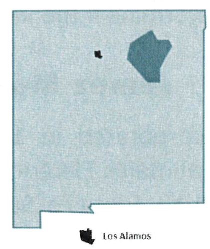


Kit Carson Electric Cooperative ("KCEC"), established in 1944 and headquartered in Taos, New Mexico, provides electric, internet and propane delivery services to members in Taos, Colfax, and Rio Arriba Counties. KCEC is the second largest cooperative in New Mexico and serves approximately 25,500 residential and 4,600 commercial and industrial locations.

KCEC has focused on obtaining access to renewable energy resources, leaving Tri-State G&T in 2016 and entering into an agreement with power wholesaler Guzman Energy, with the goal of achieving 100% of daytime energy through solar power. KCEC's last base rate increase occurred in 2016, at which time the fixed fee for residential customers was increased from $14.50 to $20.50 per month. Kit Carson's average electric residential bill is approximately $91.09, or 18.60 cents per kWh.

KCEC had 85 full time employees as of December 31, 2022, or approximately 354 billed locations per employee.

5.3 Mora-San Miguel Electric Cooperative

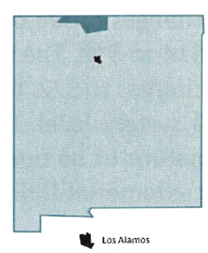


Mora-San Miguel Electric Cooperative ("MMEC") serves approximately 11,431 customers in Mora, Colfax, Harding, San Miguel, and Guadalupe counties. MMEC was founded in 1940. In terms of the number of customers served, MMEC is the most comparable utility within the benchmark group to Los Alamos.

MMEC's last rate increase was effective November 2019. Customers are sorted into rate groups based on the nature of the location and apparent power levels, with all non-seasonal residential customers and commercial locations requiring less than 10 kVA transformer service receiving service under the Residential/General Service tariff and pay a $25 fixed system charge per month.

As of December 2022, MMEC had a total of 29 full time employees, or approximately 385 customers for each employee.

5.4 Northern Rio Arriba Electric Cooperative

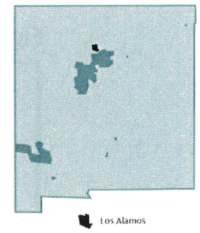


Headquartered in Chama, New Mexico, and serving Rio Arriba County, Northern Rio Arriba Electric Cooperative ("NORA") was incorporated in 1949. NORA serves approximately 2,700 residential and 450 commercial accounts, making it one of smaller cooperative providers in the state.

In August 2023, NMPRC administratively approved a rate increase for NORA customers. Under the rates effective August 1, NORA residential customers incur a monthly fixed charge of $30. The average electric bill for a NORA residential customer is $84.76 per month, or 18.84 cents per kWh.

NORA employed 13 full time personnel as of December 2022, or approximately 245 customers for each employee.

5.5 Public Service Company of New Mexico



Public Service Company of New Mexico ("PNM") is an investor-owned utility which serves some of the most densely populated areas of New Mexico, including Albuquerque, Rancho Rio, and Santa Fe. PNM provides services to approximately 490,000 residential and 60,000 commercial and industrial customers, making it the largest provider of electricity in the state.

The average PNM residential customer pays $84.87 per month for service, or 14.78 cents per kWh. PNM commercial users have higher levels of average usage than those on the LAC retail system or in the cooperatives included in the benchmark comparisons. While residential customer usage averages are slightly above the average of the cooperatives, they are generally in line with those of LAC. Average operating costs per customer have historically been higher than both LAC and the Cooperative average.

LAC Management indicated that PNM is one of the two most relevant benchmarks in their internal assessment of rates.

5.6 Benchmark Utility Usage, Cost, and Bill Comparison

The charts below show comparisons of the average usage levels, average cents per kWh, and average bills for residential and commercial customers of each utility in the comparison group.[6] Bills and average cost of energy may reflect differences in average levels of usage and categorization of customers into specific rate classes. LAC values shown are calendar year 2022 for consistency purposes, with the exception of estimated average bills and cost per kWh, which is recalculated for the rate increase occurring in October of 2023.

[6] Data from PRC Annual Reports, and U.S Energy Information Administration EIA-861 Schedules, and findenergy.com. GDS has not independently validated amounts shown.

Figure 16 - Comparison of Average Monthly Usage per Bill – Residential

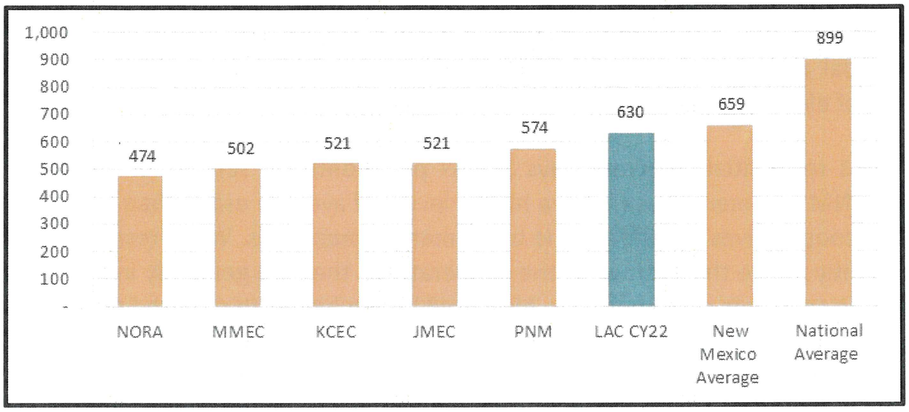


Figure 17 - Comparison of Average Cents Paid per kWh – Residential

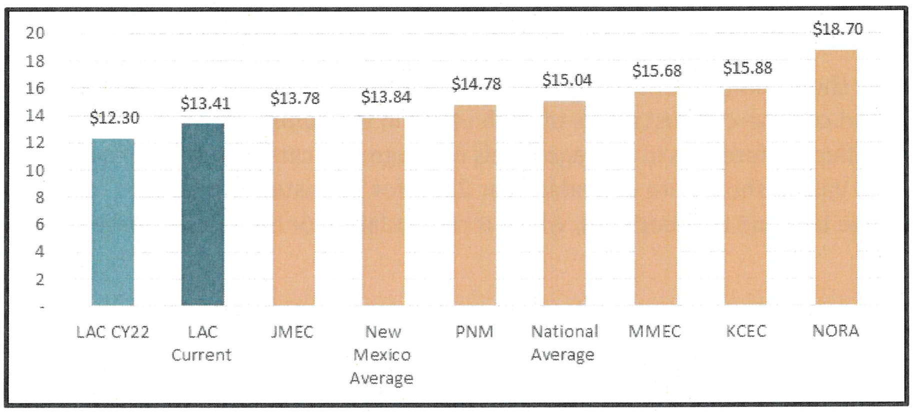


Figure 18 - Comparison of Average Bill – Residential[7]

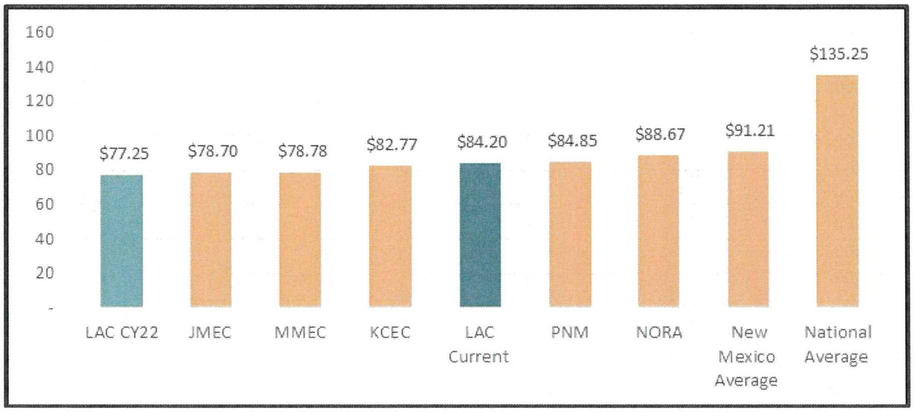
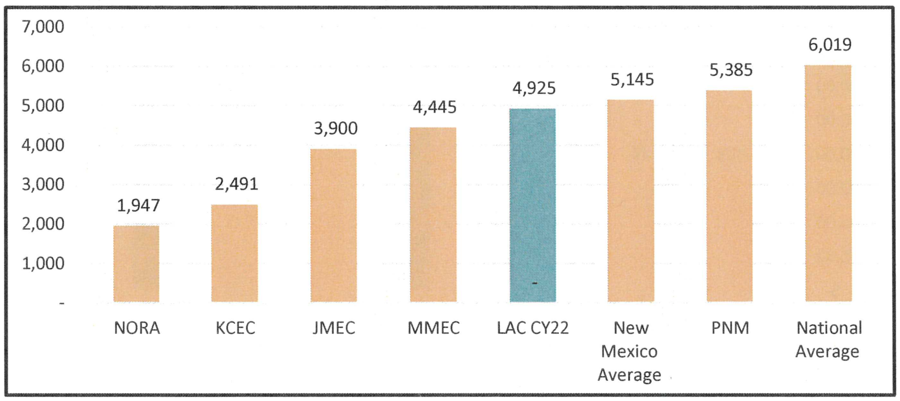


Figure 19 - Comparison of Average Monthly Usage per Bill - Commercial[8]



[7] Reflects utility-specific levels of usage in calendar year 2022. New Mexico average residential consumption levels are approximately 73% of the national average.

[8] LAC Commercial values shown include Commercial, County (excluding water production), and Educational ratepayers.

Figure 20 - Comparison of Average Cents Paid per kWh – Commercial

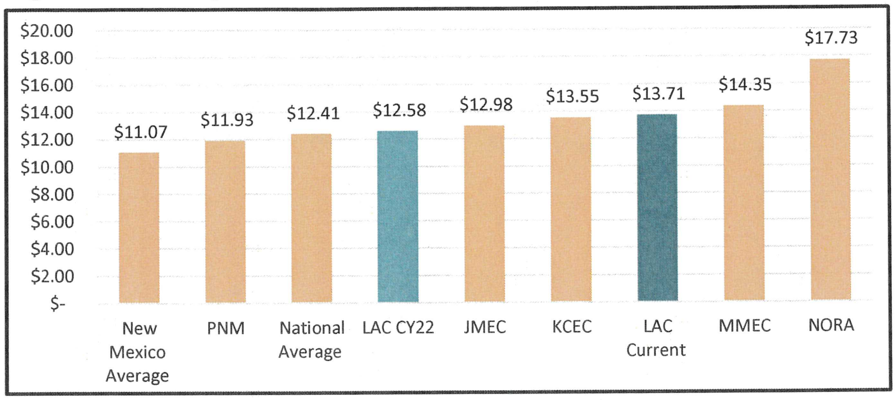
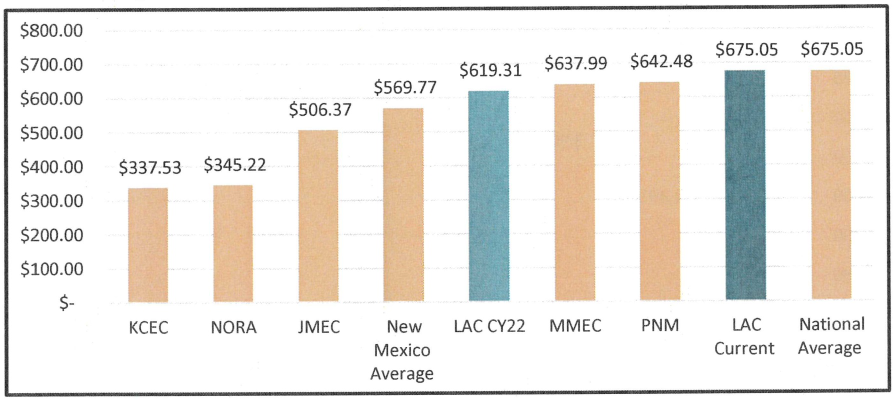
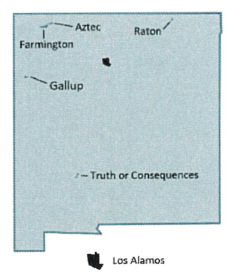


Figure 21 - Comparison of Average Bill – Commercial



5.7 Comparison to New Mexico Municipal Utilities



A limited number of municipal utilities operate in New Mexico, and less detailed financial and operating information is available as they are not regulated by the NMPRC. Though not included in the benchmark group, a brief comparison to other municipal utilities operating in New Mexico is appropriate. Of the municipal utilities in New Mexico, the City of Gallup, located in the Western part of the state, is most comparable in terms of number of locations served, with approximately 8,500 residential and 2,000 commercial customers. The cities of Aztec, Raton and Truth or Consequences have significantly fewer total customers, ranging from 3,300 to 4,000, while Farmington is the largest municipal utility with approximately 46,000 total customers.

The cities of Aztec, Raton, and Farmington, have net metering rates for customers with distributed generation systems. None of the municipalities have made time-of-use rates available to customers.

5.7.1 Municipal Residential Rates

For Residential customers, municipal fixed charges range from Truth or Consequences $8.00 service charge to the City of Aztec's $35.10 charge,[9] which includes an allowance for 100 kWh. Municipal fixed

[9] July 2023-June 2024 charge.

charges tend to be lower than those of other utilities, in part due to the greater range of policy concerns inherent in the municipal ownership structure.

Figure 22 - Municipal Utility Average Usage - Residential

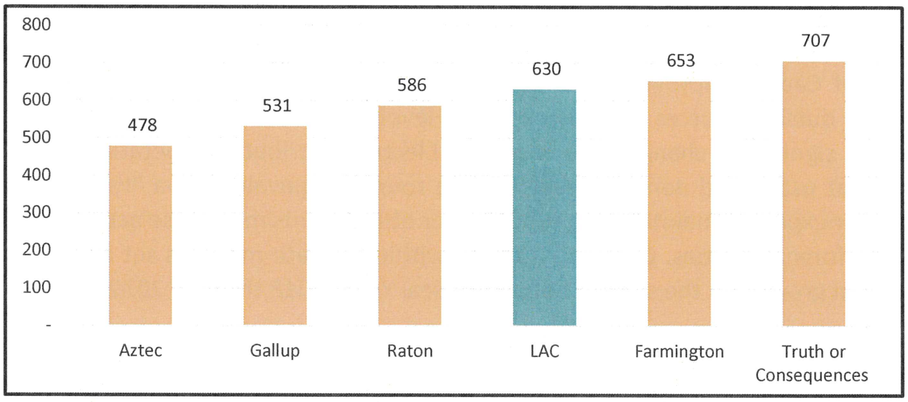


Figure 23 - Municipal Average Cents Paid per kWh – Residential

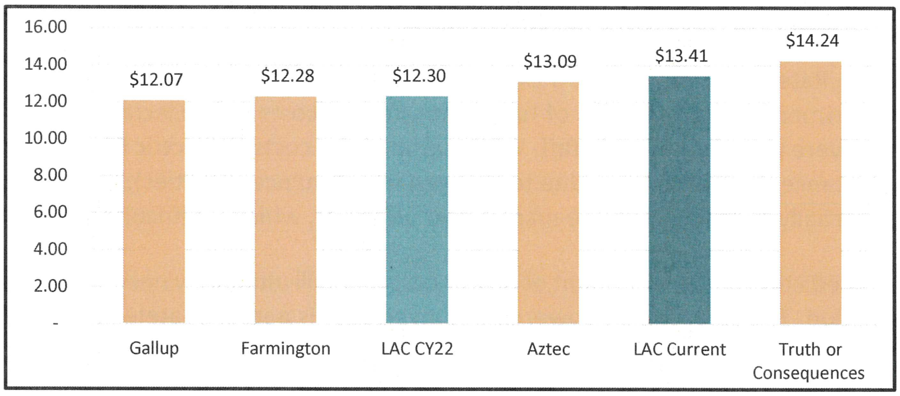
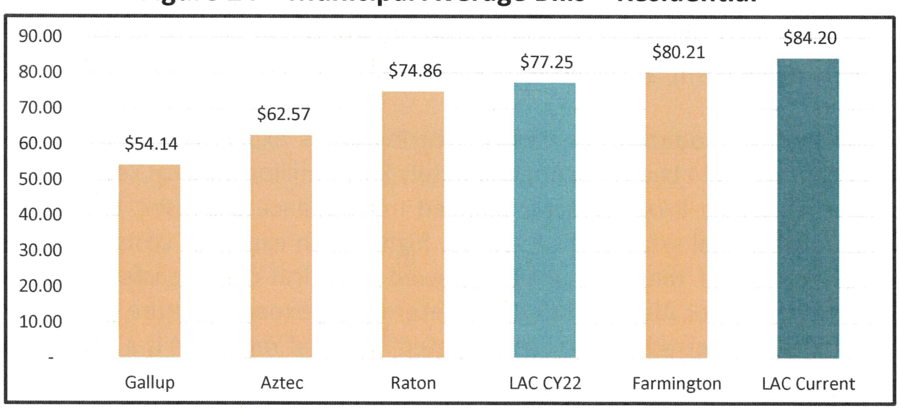


Figure 24 - Municipal Average Bills – Residential



6 Rate Study

6.1 Overview and Approach

The rate study is based on a forecast of future costs based on budgeted Fiscal Year 2024 expenditures, expected levels of Capital Improvement Project ("CIP") investment, historical billing information, and information from outside sources such as expected levels of inflation and interest rates. The forecast assumes that no significant changes are made to Electric Distribution operational or organizational structure, and that usage and demand levels will be roughly equivalent to a "typical" year. Significant weather events, unexpected maintenance expenses, or other events may cause actual costs and revenues to vary from the forecast values. Customer growth within the rate model is set at 1% growth per year based on historical growth on the system between Fiscal Years 2018 through 2022.

Data for this study was provided by Los Alamos Staff in March 2023 and was prepared for the budget process for Fiscal Year 2024. As of the time of this report, budgets for Fiscal Year 2025 were being developed.

6.2 Reliance on Los Alamos Projections

The results of the Rate Study rely both on calculations by GDS on probable future costs at the Electric Distribution department and projections of future transfers of costs from Electric Production to Electric Distribution that were prepared by LAC staff. While some of the costs at Electric Production are generally knowable (for instance, increased costs due to planned maintenance activities), the total amount of the transfer is also partially dependent on the market cost of power, which is difficult to predict.

The difficulty in predicting the total amount of power cost that will ultimately need to be recovered merits additional discussion. The total cost of power in any given year is approximately 50% of total costs to be recovered from customers, and will vary from projected amounts for numerous reasons, including some entirely outside of LAC's control. The use of base rates to recover these costs and the magnitude of the costs lead to a situation where if power costs vary materially from those expected by the utility, it may cause the results of the study to be unreliable. Partially for this reason, we recommend that the County decouple recovery of power-related costs and the cost to run the distribution utility by implementing a power cost recovery mechanism, as discussed in Section 15.

The transfer from Electric Production to Electric Distribution is expected to reduce the $9.52 million included in the Fiscal Year 2024 budget to approximately $6.81 million in Fiscal Year 2027. A large portion of this decrease is related to lower forecast planned maintenance expenses, but as the transfer is a significant portion of the total retail cost of service, higher than expected costs will necessitate higher levels of revenue. As part of the study, GDS reviewed historical cost transferred and discussed the assumptions relied upon by Los Alamos staff when determining expected future costs. We believe that a reduction in total costs transferred from those budgeted for Fiscal Year 2024 is a reasonable assumption, and costs projected for future years are in line with historical costs.

Table 3 - Transfer from Department 511

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Transfer from Dept. 511	$ 7,536,886	$ 8,074,789	$ 9,516,802	$ 8,131,600	$ 7,567,427	$ 6,806,886	$ 7,388,937	$ 8,693,960
Total	**7,536,886**	**8,074,789**	**9,516,802**	**8,131,600**	**7,567,427**	**6,806,886**	**7,388,937**	**8,693,960**

6.3 Other Projected Expenses FY24-FY28

6.3.1 Operating Expenses

Operating expenses, including administrative and interdepartmental costs, represent the day-to-day costs of operating the utility, such as employee salaries and benefits, materials and supplies consumed in operations, and contract-related costs such as software. We project a slow increase in these costs in the period from Fiscal Year 2024 through 2029.

Table 4 - O&M and A&G Expense Included in Rate Study

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Substation Maintenance	$ 53,500	$ 27,690	$ 57,580	$ 58,783	$ 60,029	$ 61,320	$ 62,657	$ 64,042
Switching Station Maintenance	64,169	67,292	195,552	199,934	204,462	209,141	213,976	218,973
OH & UG Line Maintenance	1,210,876	1,162,545	1,636,420	1,690,511	1,746,546	1,804,599	1,864,745	1,927,065
Meter Maintenance	76,595	100,150	128,669	133,390	138,291	143,379	148,662	154,148
Adminstrative and Interdepartmental	2,613,196	3,591,371	3,181,883	3,304,276	3,431,504	3,563,758	3,701,238	3,844,152
Total	**4,018,336**	**4,949,048**	**5,200,104**	**5,386,894**	**5,580,832**	**5,782,196**	**5,991,278**	**6,208,379**

6.3.2 Capital-Related Expenses

Capital-related expenses include principal and interest on existing and planned CIP, and the portion of internal costs devoted to annual construction activities. Payments on bonds issued for CIP expenditures are assumed to start the year after they are issued, and bonds are projected to be paid over a 20-year life at a 5% interest rate. Most of the increase shown is the result of issuance of debt instruments for future projects. Further discussion of the planned CIP, financing assumptions and impact on overall rates can be found in Section 7.

Table 5 - Capital-Related Expenses

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Principal and Interest Expense	$ 1,077,387	$ 923,618	$ 925,591	$ 1,096,420	$ 1,379,194	$ 2,283,994	$ 2,626,216	$ 2,919,804
Debt Service Coverage	-	-	-	-	-	-	-	-
Capital Improvement Project Expense	766,697	207,267	260,383	270,798	281,630	292,895	304,611	316,796
Total	**1,844,084**	**1,130,885**	**1,185,974**	**1,367,219**	**1,660,825**	**2,576,890**	**2,930,828**	**3,236,599**

6.3.3 Franchise Fees and General Fund Transfers

The level of Franchise Fees (In Lieu of Taxes) and the General Fund Transfer collected in rates is dependent on the total amount of revenue collected from customers. Table 6 is presented at historical amounts through Fiscal Year 2024. For Fiscal Years 2024 and 2025, rates in place for those periods have been used to calculate the amount of the transfer. For subsequent years, the amount of transfer is calculated utilizing Fiscal Year 2025 rates plus a growth factor based on historical growth in each rate class.

Table 6 - Tranfers and Reserve Funding

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
General Fund Transfer	$ 594,072	$ 602,043	$ 578,985	$ 579,064	$ 584,854	$ 590,703	$ 596,610	$ 602,576
In Lieu of Taxes	525,602	564,406	561,760	572,995	584,455	596,144	608,067	620,228
Additional Reserve Funding	-	-	-	-	-	-	-	-
Total	**1,119,674**	**1,166,448**	**1,140,745**	**1,152,059**	**1,169,309**	**1,186,847**	**1,204,677**	**1,222,804**

6.3.4 Total Revenue Requirement

Adding all of the elements discussed above results in an overall revenue requirement of $17.01 million for Fiscal Year 2024 and $16.08 million for Fiscal Year 2025. As noted above, the most significant category of costs to Electric Distribution customers is the cost transferred from Electric Production, which in some years makes up most expenses. Electric Production costs are also the driver of significant increases in cost beginning in Fiscal Year 2029.

Table 7 - Total Revenue Requirement

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
O&M and A&G	$ 4,018,336	$ 4,949,048	$ 5,200,104	$ 5,386,894	$ 5,580,832	$ 5,782,196	$ 5,991,278	$ 6,208,379
Purchased Power	7,536,886	8,074,789	9,516,802	8,131,600	7,567,427	6,806,886	7,388,937	8,693,960
Capital-Related	1,844,084	1,130,885	1,185,974	1,367,219	1,660,825	2,576,890	2,930,828	3,236,599
Transfers and Reserves	1,119,674	1,166,448	1,140,745	1,152,059	1,169,309	1,186,847	1,204,677	1,222,804
Total	**14,518,979**	**15,321,171**	**17,043,624**	**16,037,772**	**15,978,393**	**16,352,819**	**17,515,720**	**19,361,743**

6.4 Expected Financial Results - July 2024 Rates

The expected financial results under rates that will be in place as of July 2024 are shown below. As a result of the two 9% increases to base rates in October 2023 and July 2024, base rates are expected to create enough revenue to fund system operations and to begin to rebuild reserve balances. The values below do not include any additional funding to meet debt service coverage requirements, which are set at 1.6 times principal and interest expense each year. Increased revenues may be required to meet the 1.6 debt service coverage target starting in Fiscal Year 2027.

Table 8 - Projected Results at July 2024 Rates

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Total Cost of Service	$ 14,518,979	$ 15,321,171	$ 17,043,624	$ 16,037,772	$ 15,978,393	$ 16,352,819	$ 17,515,720	$ 19,361,743
Less: Other Revenues	(15,326)	(200,475)	(200,000)	(325,000)	(325,000)	(325,000)	(325,000)	(325,000)
Base Rate Revenue Requirement	14,503,653	15,120,696	16,843,624	15,712,772	15,653,393	16,027,819	17,190,720	19,036,743
Base Rate Revenues - July 2024	13,969,663	14,122,238	14,716,218	16,738,790	16,906,177	17,075,239	17,245,992	17,418,452
Over/(Under) Recovery - $	**(533,991)**	**(998,458)**	**(2,127,407)**	**1,026,018**	**1,252,785**	**1,047,421**	**55,272**	**(1,618,291)**
Over/(Under) Recovery - %	**-4%**	**-7%**	**-13%**	**7%**	**8%**	**7%**	**0%**	**-9%**

As discussed above, the decreases in power-related costs transferred from Electric Production to Electric Distribution are the primary driver of lower total costs to serve in period from Fiscal Year 2025 through 2027 relative to Fiscal Year 2024. In that period, power-related costs are expected to be reduced between $1.3 and $2.7 million below the level budgeted in Fiscal Year 2024. If the cost reductions do not materialize, there may be significantly lower surpluses or under-recovery of costs in that period.

6.5 Recommended Approach to Rate Increases

The forecast results show the need for potential revenue increases starting in Fiscal Year 2028, at which point the revenues produced by rates are not sufficient to both cover expenses and to provide coverage for debt service and for unforeseen expenses. We recommend that LAC compare results of this study with actual financial results in Fiscal Year 2027 with the goal of assessing whether an increase is required in Fiscal Year 2028. Phasing in the increase in two steps over Fiscal Year 2028 and Fiscal Year 2029, similar to the recent increases to rates, will allow the utility to limit the immediate impact on customer bills.

A phased increase of 8% in Fiscal Year 2028 and 8% in Fiscal Year 2029 would provide sufficient revenues to fund operations through at least 2030 based on current Rate Study Model results and would achieve 1.6 debt service coverage targets.

Table 9 - Projected Results with 8% increase in Fiscal Years 2028 and 2029

Description	FY22	FY23 Projected	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Total Cost of Service	$ 14,518,979	$ 15,321,171	$ 17,043,624	$ 16,037,772	$ 15,978,393	$ 16,352,819	$ 17,515,720	$ 19,361,743
Less: Other Revenues	(15,326)	(200,475)	(200,000)	(325,000)	(325,000)	(325,000)	(325,000)	(325,000)
Base Rate Revenue Requirement	14,503,653	15,120,696	16,843,624	15,712,772	15,653,393	16,027,819	17,190,720	19,036,743
Base Rate Revenues - July 2024	13,969,663	14,122,238	14,716,218	16,738,790	16,906,177	17,075,239	18,625,671	20,316,882
Over/(Under) Recovery - $	**(533,991)**	**(998,458)**	**(2,127,407)**	**1,026,018**	**1,252,785**	**1,047,421**	**1,434,951**	**1,280,139**
Over/(Under) Recovery - %	**-4%**	**-7%**	**-13%**	**7%**	**8%**	**7%**	**8%**	**7%**

7 Capital Project Funding Strategy and Impact

Other than the cost of power, expenses incurred to run the daily utility operations tend to grow at a steady pace. While certain costs may outpace general inflationary pressure, these tend to be offset by savings, prices fixed by long-term contracts, and inflation-resistant items. The utility has an obligation to provide service and therefore has limited control over the day-to-day costs of maintaining and operating the system. However, some control is available over the timing and financing of capital projects. As part of this study, LAC management requested a limited analysis of the comparative impact that debt financing projects would have against funding projects through existing cash balances or revenues collected through rates.

While the expected impact of future capital outlays is within the scope of a rate study and rate study models can typically be adjusted to show the financial and rate effects of various forms of financing, decisions as to how specific assets are funded, optimal capital structures, the prudence of incurring debt, and the relative benefits of specific financial strategies are the responsibility of management and governance. We make no recommendations as to those topics other than that they are best discussed with a properly accredited municipal or financial advisor.

At a high level, the relative effect of debt funding in comparison to internally funding capital projects is relatively clear. We recommend that rates always provide some cushion over the actual cost of running the utility to grow reserves and meet certain debt obligations such as coverage ratios. To the extent that reserves are available in excess of that required to ensure stable utility operations and meet obligations, these reserves may be deployed to offset the need for bond funding, saving the utility (and therefore customers) from that portion of interest and principal cash outflows over the life of the bond.[10]

In addition to interest and principal payments, rates may increase due to additional coverage needs related to the debt, and any revenue-based components of the revenue requirement (such as transfers or franchise fees) will be increased proportionally. While debt financing costs more over the long term than funding through existing reserves, it has the advantage of more closely matching the timing of cost recovery from customers with the benefits provided by the asset.

The immediate effect on rates of $1 million in debt financing, assuming a 5% rate, 20-year bond, and standard amortization over the repayment period, would total approximately $80 thousand per year, or around $0.70 on the average customer bill across all rate classes. Increasing that amount to recover a 1.6 debt service coverage ratio and account for franchise fees and revenue transfers paid by residential and commercial customers would result in a total increase in the average bill of around $1.30. Over the period of the issuance, the debt would result in around $300 in additional charges to the average customer over the twenty-year life of the bond.

Debt costs are often assigned to customers based on allocation of the overall investment in plant, as it is the overall investment in providing service, not the financing of specific assets, that is relevant. Levels of intra- and inter-class subsidization, such as those due to the proportional recovery of fixed costs through fixed charges, changes in customer usage patterns, and other factors would also influence the impact on a specific customer class.

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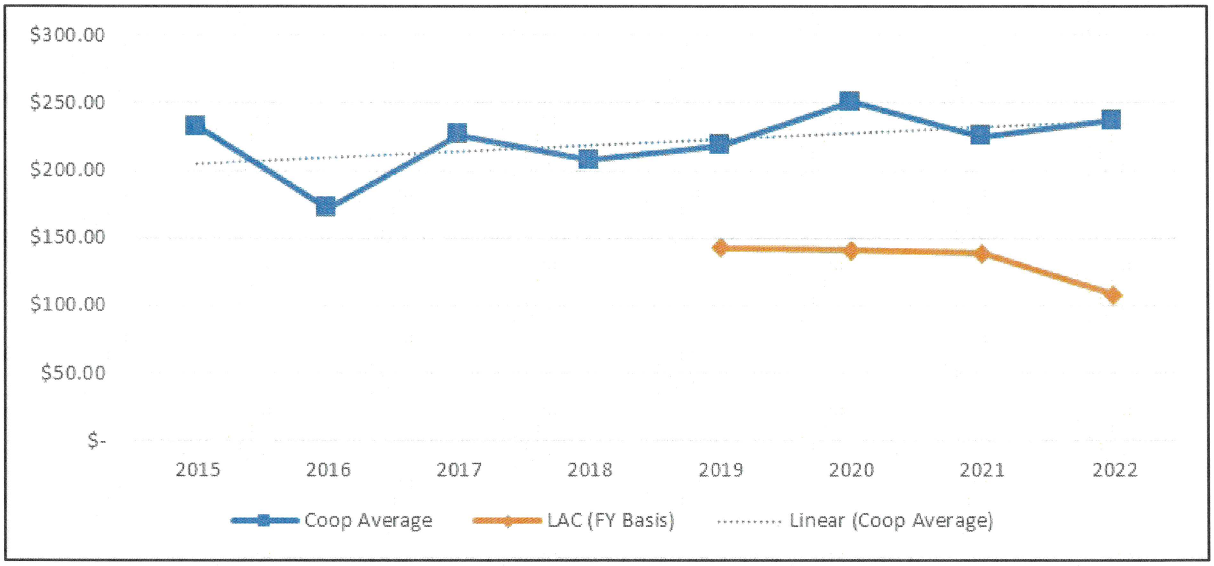
[10] Ignoring the time value of money or opportunity costs, which are outside the scope of this review.

7.1 Benchmark Debt Service Averages

Currently, debt service cost on a per-customer basis for LAC is lower than utilities in the cooperative benchmark group.

Figure 25 - Average Debt Service per Connection



Higher levels of debt service per customer are often indicative of lower customer density, as higher investment per customer is required. This dynamic, along with the financial structure differences between municipal and cooperative utilities, may explain the relatively lower levels of debt per connection occurring at LAC.

7.2 Capital Costs Included in Rate Study

A schedule of the capital costs included in future rates is shown below.

Table 10 - Schedule of Electric Distribution Capital Projects

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
LA URD Replacement	$ 1,200,000	$ 200,000	$ 1,250,000	$ 1,800,000	$ 1,500,000	$ 1,500,000
White Rock URD Replacement	-	1,200,000	2,200,000	1,800,000	1,200,000	1,500,000
OH System Replacement	200,000	100,000	450,000	450,000	450,000	450,000
EA-4 Power Line Replacement	250,000	-	7,500,000	-	-	-
GWS/ED Facilities at WR WWTP	-	-	75,000	-	-	-
East Gate Substation	-	-	-	300,000	-	-
Townsite Station Breaker Replacements	-	-	-	-	750,000	-
White Rock Substation Unit 1 Transformer	-	-	-	-	-	1,500,000
Total CIP	**1,650,000**	**1,500,000**	**11,475,000**	**4,350,000**	**3,900,000**	**4,950,000**

7.3 Financing Costs

Funding of all projects is assumed to be provided through debt issuances, with payments beginning in the year after the debt has been issued. Bonds are assumed to be 5% and paid off over 20 years.

Table 11 - Principal and Interest Expense Included in Rate Study

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
2010 Bond	$ 187,806	$ 312,056	$ 478,842	$ 477,944	$ 479,818	$ 474,854
2014 Tax Exempt Bond	671,739	587,864	588,829	584,772	587,437	584,845
FY2024 Bond Issuance	-	132,400	132,400	132,400	132,400	132,400
FY2025 Bond Issuance	-	-	120,364	120,364	120,364	120,364
FY2026 Bond Issuance	-	-	-	920,784	920,784	920,784
FY2027 Bond Issuance	-	-	-	-	349,055	349,055
FY2028 Bond Issuance	-	-	-	-	-	312,946
Total Principal and Interest Expense	**859,546**	**1,032,321**	**1,320,435**	**2,236,264**	**2,589,858**	**2,895,249**

Changes in interest rates do not materially affect the forecasted overall cost of service, with a 2% change in rates resulting in an approximate $200,000 change in total interest expense in Fiscal Year 2029.

Applying available cash to reduce debt-funded CIP instead of rebuilding reserve funds would marginally reduce the total interest payments that would need to be covered by rates, at the expense of eliminating reserve balances that may be needed to fund operations.

Table 12 - Cash and Debt Funding of CIP

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Cash-Funded CIP	$ -	$ 1,026,018	$ 1,335,115	$ 1,236,884	$ 805,892	$ 937,278
Debt-Funded CIP	1,650,000	473,982	10,139,885	3,113,116	3,094,108	4,012,722
Total CIP	**1,650,000**	**1,500,000**	**11,475,000**	**4,350,000**	**3,900,000**	**4,950,000**

Table 13 - Debt Service Expense – Cash Applied to CIP

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
2010 Bond	$ 187,806	$ 312,056	$ 478,842	$ 477,944	$ 479,818	$ 474,854
2014 Tax Exempt Bond	671,739	587,864	588,829	584,772	587,437	584,845
FY2024 Bond Issuance	-	132,400	132,400	132,400	132,400	132,400
FY2025 Bond Issuance	-	-	38,034	38,034	38,034	38,034
FY2026 Bond Issuance	-	-	-	813,651	813,651	813,651
FY2027 Bond Issuance	-	-	-	-	249,804	249,804
FY2028 Bond Issuance	-	-	-	-	-	248,279
Total Principal and Interest Expense	**859,546**	**1,032,321**	**1,238,105**	**2,046,800**	**2,301,144**	**2,541,868**
Difference to 100% Debt Funded CIP	**-**	**-**	**82,330**	**189,463**	**288,714**	**353,381**

8 Reserve Balances

The County's financial policy requires it to meet specific reserve targets, which are expected to be met within ten years. While our forecast is limited to five years, LAC's ten-year projections included in budget documents do result in full funding of required reserves. As with all projections relating to LAC financial positions, achieving projected results is highly dependent on certain projections made by the County as to future levels of power-related costs.

As revenues are collected, any amount net of the immediate cost of providing service increases or reduces the balance available for funding reserves. Assignment of total reserve balances to specific reserves follows LAC's policy for funding reserves, with balances being assigned to a reserve only once the previous reserve in the hierarchy is deemed fully funded.

The projected balances below incorporate the 9% increases approved by the City Council in fiscal years 2024 and 2025 as well as the 8% increases recommended for fiscal years 2028 and 2029.

8.1 Bond Reserve

LAC's Bond Reserve is fully funded and is expected to remain fully funded throughout the study period.

8.2 Operations Reserve

The Operations Reserve has a target equal to 180 days of budgeted O&M expenditures. The Rate Study Model gives the Operations Reserve priority for funding once the Bond Reserve is fully funded. Within the rate study period, the target balance for the Operations Reserve is between $2.9 and $3.4 million. The Operations Reserve is anticipated to be fully funded in Fiscal Year 2027.

Table 14 - Forecast Operations Reserve Balance

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Total O&M	$ 5,779,089	$ 5,965,958	$ 6,165,686	$ 6,372,899	$ 6,587,888	$ 6,810,955
Day of Cash Target	180	180	180	180	180	180
Reserve Target Balance	2,889,544	2,982,979	3,082,843	3,186,450	3,293,944	3,405,478
Balance Achieved - $	-	1,026,018	2,278,803	3,186,450	3,293,944	3,405,478
Balance Achieved - %	0%	34%	74%	100%	100%	100%

8.3 Capital Reserve

The Capital Reserve targets a balance equal to the annual depreciation expense plus 2.5%. The Capital Reserve is almost entirely funded by the end of the study period.

Table 15 - Forecast Capital Reserve Balance

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Reserve Target Balance	$ 1,283,738	$ 1,447,097	$ 1,725,769	$ 1,843,003	$ 1,954,472	$ 2,077,472
Balance Achieved - $	-	-	-	139,774	1,011,399	2,049,172
Balance Achieved - %	0%	0%	0%	8%	52%	99%

8.4 Rate Stabilization Reserve

The Rate Stabilization Reserve target is based on the cost of commodities for utilities in which a pass-through has not been adopted. The Rate Stabilization Reserve remains unfunded throughout the study period.

Table 16 - Forecast Rate Stabilization Reserve

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Reserve Target Balance	$ 9,516,802	$ 8,131,600	$ 7,567,427	$ 6,806,886	$ 7,388,937	$ 8,693,960
Balance Achieved - $	-	-	-	-	-	-
Balance Achieved - %	0%	0%	0%	0%	0%	0%

Revenues estimated to be available for reserve funding equal approximately $1.55 million per year, so recovery of the Rate Stabilization Fund alone will take over five years. If the County elects to move forward with GDS' recommendation that a pass-through mechanism be adopted for electricity costs, it may eliminate the need for this reserve, allowing full funding to be achieved at an earlier date.

8.5 Contingency Reserve

The Contingency Reserve is based on the replacement cost of the single largest piece of equipment that is subject to failure and is determined by the DPU Asset Team. The Contingency Reserve remains unfunded throughout the study period under recommended rates.

Table 17 - Forecast Contingency Reserve

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Reserve Target Balance	$ 546,722	$ 554,922	$ 563,246	$ 571,695	$ 580,270	$ 588,974
Balance Achieved - $	-	-	-	-	-	-
Balance Achieved - %	0%	0%	0%	0%	0%	0%

8.6 Total Reserve Funding Achieved in Study Period

Under recommended rates, including the forecast 8% increases in Fiscal Years 2028 and 2029, reserve balances produced are expected to achieve approximately 50% funding by Fiscal Year 2029, as shown below. If the 1.6 debt service coverage factor is maintained, based on debt expenses in Fiscal Year 2029, around $1.75 million of revenues in excess of expenses will be produced annually.

Table 18 - Target Reserve Balances – Total Reserve Needs

Description	FY24 Budget	FY25	FY26	FY27	FY28	FY29
Bond Reserve	$ 1,249,548	$ 1,480,167	$ 1,861,912	$ 3,083,392	$ 3,545,392	$ 3,941,735
Operations Reserve	2,889,544	2,982,979	3,082,843	3,186,450	3,293,944	3,405,478
CapEx Reserve	1,283,738	1,447,097	1,725,769	1,843,003	1,954,472	2,077,472
Rate Stability Reserve	9,516,802	8,131,600	7,567,427	6,806,886	7,388,937	8,693,960
Contingency Reserve	546,722	554,922	563,246	571,695	580,270	588,974
Total Reserve Needs	**15,486,353**	**14,596,766**	**14,801,198**	**15,491,425**	**16,763,015**	**18,707,619**

Table 19 - Total Reserve Balances Achieved Under Recommended Rates

Description	FY24	FY25	FY26	FY27	FY28	FY29
Bond Reserve	$ 1,249,548	$ 1,480,167	$ 1,861,912	$ 3,083,392	$ 3,545,392	$ 3,941,735
Operations Reserve	-	1,026,018	2,278,803	3,186,450	3,293,944	3,405,478
CapEx Reserve	-	-	-	139,774	1,011,399	2,049,172
Rate Stability Reserve	-	-	-	-	-	-
Contingency Reserve	-	-	-	-	-	-
Total Reserves Achieved - July 2024 Rates	**1,249,548**	**2,506,185**	**4,140,715**	**6,409,616**	**7,850,735**	**9,396,384**
Base Rate Increase Recommended	**9.0%**	**9.0%**	**0.0%**	**0.0%**	**5.4%**	**10.0%**
Deficiency - $	**14,236,806**	**12,090,581**	**10,660,483**	**9,081,810**	**8,912,280**	**9,311,234**
Deficiency - %	**92%**	**83%**	**72%**	**59%**	**53%**	**50%**

8.7 Projection of Reserve Balances

We project that if revenues producing the required 1.6 debt service coverage ratio are maintained, full funding of reserves will be achieved by approximately Fiscal Year 2037. To estimate the increases required to meet targeted reserve balances, GDS projected future reserve balances beyond the study period. In making this estimate, this report made the following assumptions:

- The required Bond Reserve would stay at approximately $4 million.
- The Operations Reserve, CapEx Reserve, and Rate Stability Reserve required balances would grow by approximately 3%, the same value projected during the study period.
- The CapEx Reserve needs would also grow at approximately 1.5%, which is equal to the average over the study period and the same value used by LAC Staff for internal estimates.
- Total reserve balances would increase by approximately $1.55 million per year as a result of excess cash produced by the Debt Service Coverage calculation.

Our estimate shows that under the assumptions above, total reserve needs as of the end of Fiscal Year 2035 are $21.9 million, as shown below. As of Fiscal Year 2025, we estimate that a relatively low increase over those needed to maintain a 1.6 debt service coverage ratio is needed to fully fund reserves by Fiscal Year 2035. As with all projections of LAC financial performance, achieving results is highly dependent on the cost of power generation and purchases.

Table 20 - Projected Reserve Balance Needs, Fiscal Years 2029-2035

Description	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Bond Reserve	3,941,735	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000
Operations Reserve	3,405,478	3,520,574	3,639,561	3,762,569	3,889,735	4,021,198	4,157,105
CapEx Reserve	2,077,472	2,147,685	2,220,272	2,295,312	2,372,888	2,453,085	2,535,994
Rate Stability Reserve	8,693,960	8,987,794	9,291,559	9,605,591	9,930,236	10,265,854	10,612,815
Contingency Reserve	588,974	597,809	606,776	615,878	625,116	634,493	644,010
Total Reserve Needs	**18,707,619**	19,253,863	19,758,169	20,279,350	20,817,975	21,374,631	21,949,923

9 Cost of Service Study

9.1 Overview and Approach

The performance of a COSS involves three major steps: functionalization, classification, and allocation. Unlike the rate study, the COSS is a snapshot of a historical period (with known changes as appropriate). In each step, the current cost and investment necessary to provide service are distributed with the purpose of gaining an understanding of the overall cost of serving a specific customer class and the main drivers of those costs.

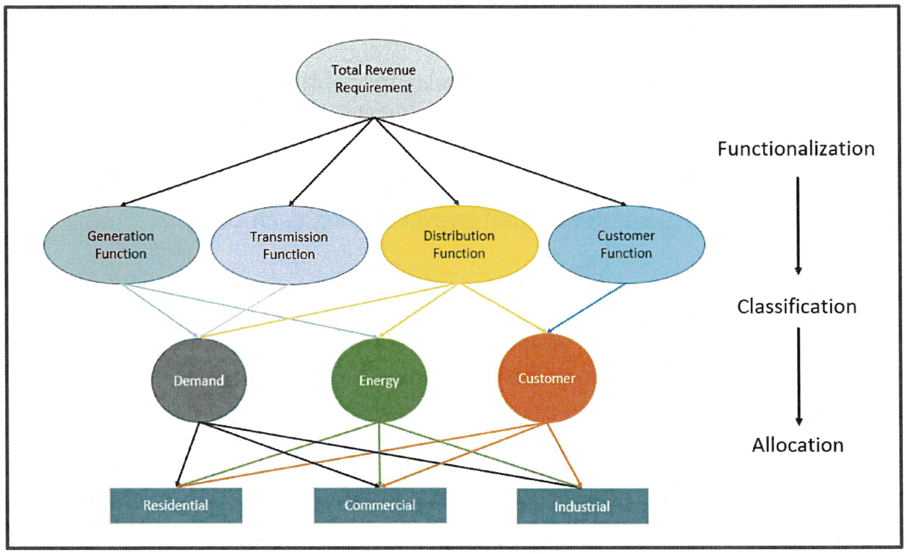
In preparing the COSS, GDS has generally followed the guidelines provided by the National Association of Regulated Utility Commissioners ("NARUC"), which is viewed as the industry standard source authority. As NARUC's last manual covering the allocation of electrical costs was published in 1992, GDS has also pulled from other authoritative sources and our industry expertise gained from participation in the preparation of COSS for both regulated and non-regulated entities when changes in methodology were required due to increased availability of information, or evolutions in industry standards.

Departures from industry standards also occurred due to differences in accounting practices between regulated and non-regulated entities or situations unique to LAC. Instances where especially unusual, challenging, subjective, or complex judgements must be made as to the proper allocation of a given cost, if any, are emphasized in the discussion below.

9.1.1 Performance of a COSS

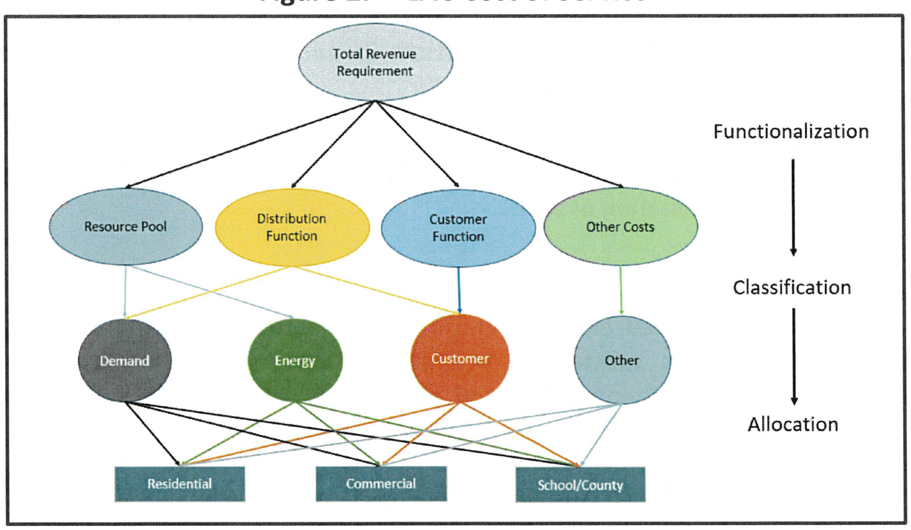
There are five main steps in a COSS. The first is to determine the overall revenue requirement to be assigned to retail customers. This total revenue requirement is then split by what major function of the utility (*e.g.* power production or customer service) is supported by the cost, a process referred to as functionalization. Functionalized costs are then assigned, or classified, to the most relevant driver of the cost. For instance, the cost of mailing utility bills to customers will be classified as customer-related, as the cost of billing is the same for each customer and varies depending on the number of customers taking service. Classified costs are then allocated to customer classes based on the most relevant metric, whether that be consumption, demand levels, or number of customers in that class. Finally, the resulting total allocated expense for each rate class is compared to collections from current revenues to identify areas where inter-class subsidies may be occurring and to inform rate design decisions.

Figure 26 - COSS Steps



For the LAC COSS, the generation and transmission functions have been consolidated into the Resource Pool function, and debt, and revenue-related costs are designed as "other costs" and are allocated separately at the end of the process, as shown below. No distribution costs that would be classified as energy-related are present at LAC. Consistent with the NARUC methodology, a portion of the cost of maintaining distribution equipment such as electrical lines, poles, conductors, and transformers, representing the fixed costs needed to provide the customer with basic service, is designated as customer-related.

Figure 27 - LAC Cost of Service



9.2 Revenue Requirement Utilized for COSS

The COSS is based on the budgeted expenditures for Fiscal Year 2024, modified as discussed in the Rate Study portion of the report above. The actual cost of serving a customer class will vary from year to year as usage and demand patterns fluctuate and operational resources are deployed to address specific tasks.

When comparing the cost to serve a class to the revenues produced at the individual customer or class level, the rates that will be effective July 2024 have been utilized.

No additional revenues are included in the cost of service for contingency or for building up reserve funds. We believe that this is appropriate as the output of the COSS will be compared against revenues created by current rates that likewise do not include a specific contingency or reserve component. From a cost allocation standpoint, a generally acceptable approach to "blanket" items, such as the cost of building general reserves, are allocated based on the total cost of serving each class.

9.3 Functionalization

The general functionalization of the overall LAC Electric Production ("Resource Pool") and Electric Distribution ("ED") revenue requirement is shown below. The principles behind the assignment of costs are discussed in detail below for each area of utility operations.

Table 21 - General Functionalization of Total Costs

		Production		Distribution				Cust. Service	
Cost Component	**Total**	Demand	Energy	Demand	Customer	Metering	Lighting	**and Billing**	**Revenue**
Resource Pool	$ 8,131,600	$ 3,496,588	$ 4,635,012	$ -	$ -	$ -	$ -	$ -	$ -
Admin. & Overhead	3,304,276	-	-	773,371	490,257	63,164	1,118	1,976,366	-
Substation	258,717	-	-	258,717	-	-	-	-	-
UH & OH Lines	1,631,704	-	-	864,803	766,901	-	-	-	-
Transformers	56,109	-	-	29,738	26,371	-	-	-	-
Meters	133,390	-	-	-	-	133,390	-	-	-
Area Lighting Direct	2,698	-	-	-	-	-	2,698	-	-
Other	270,798	-	-	140,791	106,893	22,619	496	-	-
Debt Service	1,096,420	-	-	600,100	454,206	42,114	-	-	-
In Lieu of Taxes	572,995	-	-	-	-	-	-	-	572,995
Franchise Fees & Transf.	724,397	-	-	-	-	-	-	-	724,397
Other Revenues	(325,000)	-	-	-	-	-	-	-	(325,000)
Total	**$ 15,858,105**	**$ 3,496,588**	**$ 4,635,012**	**$ 2,667,520**	**$ 1,844,629**	**$ 261,286**	**$ 4,312**	**$ 1,976,366**	**$ 972,392**
% of Total	100%	22%	29%	17%	12%	2%	0%	12%	6%

9.3.1 Functionalization of Electric Distribution Expense

Expenses arising from the Electric Distribution Division are split into three functions based on their underlying nature. LAC does not use the FERC set of regulatory accounts that is assumed to be in place in the guidance provided by NARUC; however, the departments within Electric Distribution provide sufficient basis for a reasonable functionalization of costs.

9.3.1.1 Distribution Function

Distribution costs are those related to the operation and maintenance of the distribution system – primarily distribution lines, poles, substations, switching stations, transformers, and meters. All costs within ED that pertain directly to operating and maintaining these assets, such as overhead line replacement costs, were directly assigned to the Distribution Function.

In addition, a portion of total administrative and general costs were assigned to the distribution function based on the relative amount of direct cost assigned to the distribution and customer functions.

9.3.1.2 Customer Function

For LAC, customer service call expenses and Administrative and General Clearing costs have been directly assigned to the Customer Function. Those administrative costs not allocated to the Distribution Function have been assigned to the Customer Function.

9.3.1.3 Other Costs

Other costs consist of revenue- and debt-related elements of the cost of service. As the drivers of these costs are separate from the distribution and customer functions of the utility, they are broken out into a catch-all “other” category of costs.

9.3.2 Functionalization of Resource Pool Costs

The entire budgeted transfer of production and purchased-power expense transferred from the Electric Production Division to the Electric Distribution Division have been functionalized as production-related.

In the case of Los Alamos County, the existence of the power pool represents a unique circumstance which merits additional discussion. Despite being made up of a mix of generation unit expense, transmission costs, and power purchases, the ultimate distribution of the pool is controlled by the contract between the pool participants. The internal allocation of these costs within the pool is performed through a similar process as the retail COSS study – all costs are production, so functionalization is not necessary, but classification (between demand and energy) and allocation to pool participants is performed each month.

Fixed and variable costs are assigned to the demand and energy functions respectively. Energy-related costs are allocated between participants based on usage. The allocation of demand costs between pool participants is determined by the relative contribution to the largest coincident peak demand recorded in the previous 12 months.

The principles of cost causation require that the power pool’s internal allocation structure be used for purposes of the study, as the ultimate cost to LAC ratepayers is determined on that basis. Accordingly, GDS has adopted the budgeted split between pool participants as well as the energy and demand classifications utilized by the pool. Further discussion of the effect of the cost allocation within the Resource Pool can be found in Section 11.

9.4 Classification

Classification of costs has traditionally been the step which draws the most debate from utility analysts, as it has the greatest effect on the ultimate distribution of costs and requires judgements to be made as to the underlying nature of costs. The NARUC Cost Allocation Manual[11] anticipates the use of Demand, Energy, Customer, and Revenue classifications. GDS has adopted these standard classifications with additional classifications added where appropriate.

9.4.1 Classification of Resource Pool Costs

The classification of production costs is an area generating the most debate among utility experts. While investment and expenses related to transmission, distribution, and customer-related costs tend to be relatively homogeneous from utility to utility, production costs (which include both generation and market power purchases) differ from system to system. Production costs are typically split between demand and energy classifications; however, each generation type has different characteristics that may make a given approach appropriate. A variety of allocation factors have been developed based on whether

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[11] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992.

the plant is utilized to respond to base load or peaking demands and judgements as to the major drivers of costs.

As part of the rate study, GDS has reviewed the internal allocation of costs for the Resource Pool. The costs incurred in the power pool are allocated between participants monthly. The methods used to allocate costs between participants differs slightly from those typically adopted in retail rate proceedings, in which contributions to system coincident peak demand and average demand levels are often used to allocate production costs. As stated above, the direct driver of costs to LAC retail customers is ultimately the allocation of costs within the pool. Accordingly, we have adopted the internal classification of costs within the pool.

Table 22 - Classification of Resource Pool Costs

		Production		Distribution				Cust. Service	
Cost Component	Total	Demand	Energy	Demand	Customer	Metering	Lighting	and Billing	Revenue
Resource Pool	$ 8,131,600	$ 3,496,588	$ 4,635,012	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 8,131,600**	**$ 3,496,588**	**$ 4,635,012**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
% of Total	100%	43%	57%	0%	0%	0%	0%	0%	0%

9.4.2 Classification of Distribution-Functionalized Costs

Distribution costs are generally classified as being either customer- or demand-related. Meter and service-related costs are assigned directly to the customer classification, while station expenses are directly assigned to the demand classification. Other distribution expense items (*e.g.* OH lines maintenance, etc.) are allocated between classifications as appropriate. This allocation is typically done using an analysis based on the underlying plant which determines the utilities' actual or theoretical "minimum" investment needed to provide service to a location. This portion of the system is deemed to be customer-related, with the remainder being demand-related. This analysis can be done on specific types of plant or can be calculated for the distribution system.

GDS analyzed several factors, including types and amounts of investment in distribution plant, demand patterns, and our experience with similar systems when determining the appropriate allocation between customer and demand-related costs. The 2014 COSS utilized a split of 47% customer and 53% demand, based on the relative investment in transformers (by size) and meters. As the relative prices of various sizes of distribution plant items tend to remain constant over long periods of time, and given the long-lived nature of distribution assets, the proportion of customer-related plant typically remains the same. In our experience, the results of a minimum system study for municipal systems such as LAC result in customer-related classifications ranging from 45% to 50%.

For this study, we determined that it would not be efficient to perform a minimum system study due to the relatively immaterial effect of the classification on total cost to serve customers. The largest effect of changing the allocation of costs from 50% customer-classified to 45% customer-classified is a $27,000 reduction in total costs assigned to the Residential class, or approximately a 0.2% change in the total revenue requirement for that class. Continuance of the 47% customer, 53% demand split from the 2014 Rate Study was deemed a reasonable and cost-effective way of allocating distribution-functionalized costs given the factors discussed above.

Table 23 - Classification of Distribution-Functionalized Costs

		Production		Distribution				Cust. Service	
Cost Component	Total	Demand	Energy	Demand	Customer	Metering	Lighting	and Billing	Revenue
Admin. & Overhead	$ 1,327,910	$ -	$ -	$ 773,371	$ 490,257	$ 63,164	$ 1,118	$ -	$ -
Substation	258,717	-	-	258,717	-	-	-	-	-
UH & OH Lines	1,631,704	-	-	864,803	766,901	-	-	-	-
Transformers	56,109	-	-	29,738	26,371	-	-	-	-
Meters	133,390	-	-	-	-	133,390	-	-	-
Area Lighting Direct	2,698	-	-	-	-	-	2,698	-	-
Other	270,798	-	-	140,791	106,893	22,619	496	-	-
Total	**$ 3,681,326**	**$ -**	**$ -**	**$ 2,067,420**	**$ 1,390,423**	**$ 219,172**	**$ 4,312**	**$ -**	**$ -**
% of Total	100%	0%	0%	56%	38%	6%	0%	0%	0%

9.4.3 Classification of Customer-Functionalized Costs

All Customer-Functionalized Costs are assumed to be related to the total number of customers served and are directly assigned to the Customer Service and Billing Classification.

Table 24 - Classification of Customer-Functionalized Costs

		Production		Distribution				Cust. Service	
Cost Component	Total	Demand	Energy	Demand	Customer	Metering	Lighting	and Billing	Revenue
Admin. & Overhead	$ 1,976,366	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,976,366	$ -
Total	**$ 1,976,366**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,976,366**	**$ -**
% of Total	100%	0%	0%	0%	0%	0%	0%	100%	0%

9.4.4 Classification of Other Costs

Other costs consist of the general fund transfer, franchise fees, and debt-related costs. The general fund transfer and franchise fees are classified as revenue-related, whereas debt service is assigned to a standalone debt classification, which is then allocated between the demand, customer, and metering classifications based on the distribution of investment in plant.

Table 25 - Classification of Debt Service

		Production		Distribution				Cust. Service	
Cost Component	Total	Demand	Energy	Demand	Customer	Metering	Lighting	and Billing	Revenue
Debt Service	1,096,420	-	-	600,100	454,206	42,114	-	-	-
Total	**$ 1,096,420**	**$ -**	**$ -**	**$ 600,100**	**$ 454,206**	**$ 42,114**	**$ -**	**$ -**	**$ -**
% of Total	100%	0%	0%	55%	41%	4%	0%	0%	0%

Table 26 - Classification of Other Costs

		Production		Distribution				Cust. Service	
Cost Component	Total	Demand	Energy	Demand	Customer	Metering	Lighting	and Billing	Revenue
In Lieu of Taxes	$ 572,995	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 572,995
Franchise Fees & Transf.	724,397	-	-	-	-	-	-	-	724,397
Other Revenues	(325,000)	-	-	-	-	-	-	-	(325,000)
Total	**$ 972,392**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 972,392**
% of Total	100%	0%	0%	0%	0%	0%	0%	0%	100%

9.5 Allocation

The allocation of costs between customer classes is based on metrics observed in Fiscal Years 2023 and 2024, including demand patterns, energy consumption, and customers served. For purposes of the COSS study, GDS utilized the same general rate classifications as used for ratemaking purposes; however, some related classes were consolidated to ease analysis and presentation of results. These changes are detailed below:

- Electric Residential (Rate Code 1000), Electric Multi-Family (Rate Code 1001), Electric Net Metering (Rate Code 1002) and Electric Residential (Rate Code 1004) were consolidated the Residential class.
- Small Commercial customers (Rate Codes 1100, 1101, 1104, and 1105) were consolidated.
- Small County (Rate Codes 1102 and 1106) were consolidated.
- Small School (Rate Codes 1103 and 1107) were consolidated.
- Large Commercial (Rate Codes 1108 and 1009) and Large Power User – Special Demand Commercial (Rate Code 1113) were consolidated into the Large Commercial class.
- Large County (Rate Codes 1110 and 1113) were grouped with the County's water treatment and pumping system.

9.5.1 Determination of Demand Allocation Factors

The 2014 Rate Study used feeder-level information to develop representative demand curves based on customer representation at that level. This study departs from that methodology due to the availability of hourly usage information from LAC's AMI system.

9.5.1.1 Use of AMI Information

While a reliable indicator of relative demand levels between classes, hourly intervals do not provide a precise measure of instantaneous demand peaks. Several other limitations exist in the AMI data that required the reported values to be modified for use in this COSS:

- Not all customers have AMI meters, and the level of AMI installations vary by rate class.
- Replacements of non-AMI meters with AMI meters occurred over the period reviewed.
- Area lights, which are unmetered, are assumed to not contribute to peak demands due to usage characteristics. Usage and non-coincident demand values were calculated based on the number of billed locations for each class of bulb.

For customer classes adequately represented by AMI information, estimates were used in instances where demand information was incomplete and observed demand values were adjusted proportionally to reflect customer counts as of December 2022.

9.5.1.2 Determination of Demand for Large Customers

GDS determined that the AMI information attributed to the customers in the "Large" customer classes (Large Commercial, Large County, Large School) did not provide a reasonable representation of the demand placed on the system by those customers because of the limited AMI deployment within those classes. As an alternative procedure for determining the level of demand to assign to each class, billing information was used. Customer load factors,[12] seasonal usage and demand patterns, and facility types were evaluated and sorted as follows:

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[12] A customer's load factor is determined by dividing maximum recorded demand by average demand and is a measure of efficiency over the period, which can help in developing an understanding of the underlying demand patterns.

- Variations and load factors were reviewed to determine if changes in usage were dependent on seasonal changes in usage or temperature. In cases where usage and demand characteristics remained constant throughout the year, an average amount of demand was assumed at the time of the system peak.
- For the remaining locations, base demand curves were assigned based on customers with similar facilities. For example, the timing of peaks for Large School users were assumed to be concurrent with those of Small School rate class customers.

After completing the procedures above, calculated demand values were verified against known utility peak values from Resource Pool data and billing information to assess the reasonability of the results.

9.5.1.3 Comparison of 2014 and 2023 Demand Factors

As mentioned above, the 2014 COSS utilized feeder-level information to develop demand allocators for each rate class. Six feeders were chosen to provide this information, with each feeder being assigned as Residential (Feeders 13, 14, 15, 16, and 18) or Commercial (Feeder 17) based on the most prevalent type of customer on that feeder. While this approach was appropriate given the lack of individual customer information available at that time, the heterogenous nature of customers served by each feeder means that the results of this analysis only provided an approximation of customer behavior. Of note, several of the feeders selected as residential had substantial non-residential populations (in one case residential customers made up only 75% of total services), and no indication is made within the study as to whether the levels of non-residential consumption occurred may make the feeder non-representative of residential load. The number of users on the feeder that were deemed to be Commercial were limited, which also would affect the demand results. Commercial feeder loads were assumed to be representative of all non-residential rate classes (*i.e.* County, School, etc.).

Two demand allocators were developed from the data collected. The first, referred to as the average coincident peak ("CP;" an average of 12 months is typically referred to as "12CP"), represents the estimated average contribution to load at the time of the monthly Resource Pool peak,[13] while the second represented each class's non-coincident peak load ("NCP"), calculated as the average of the peak load amount observed each month.

Due to differences in customer populations, usage patterns within the Resource Pool, and environmental conditions, the demand allocation factors from the 2014 and current study are not directly comparable. GDS does not use the 12CP or Average NCP allocations within this study. A comparison of the allocation values from the current and 2014 Rate Study results is shown in Table 27.

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[13] Use of the resource pool coincident peak is generally consistent with GDS' methodology for allocating costs discussed below.

Table 27 - 2014 and 2023 Demand Allocations

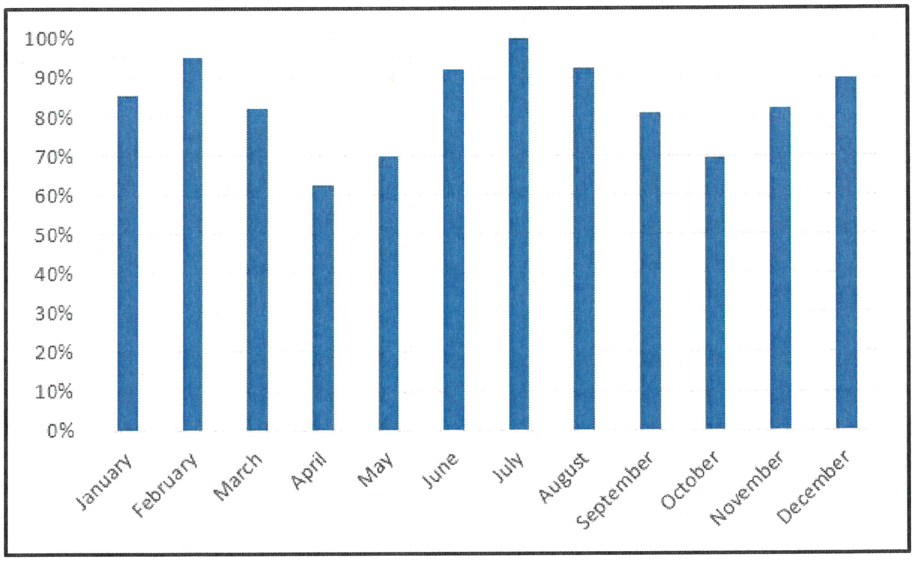
	12CP Resonsibility		Average NCP Responsibility	
Rate Class	**2014**	**2023**	**2014**	**2023**
Residential	35.7%	61.4%	50.5%	51.8%
Small Commercial	16.4%	7.6%	12.7%	9.4%
Small County	2.1%	0.8%	1.5%	1.4%
Small School	0.6%	0.5%	0.4%	1.0%
Large Commercial	25.5%	16.5%	19.6%	17.4%
Large County	11.9%	11.2%	9.1%	12.7%
Large School	7.9%	2.0%	6.1%	6.1%
Area Lighting	0.0%	0.0%	0.0%	0.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

9.5.2 Allocation of System Costs to Customer Classes

9.5.2.1 Allocation of Resource Pool Costs

The nature of a utility's peaks typically determines the most appropriate factor to use for allocating generation-related demand costs. Review of demand information reveals that while LAC generally experiences highest peak loads in the summer, winter demands are also substantial.

Figure 28 - Maximum Relative Recorded Demand – LAC Retail System



Generation-related demand costs are typically assigned on the contribution of each customer class to retail system peak demands or an average of contributions to several retail system peaks. GDS determined that because of the Resource Pool allocation, relative contributions to LAC load at the time of Resource Pool peaks was a more relevant measure of cost causation than retail system coincident peak demand. As LAC is the smaller member of the Resource Pool and therefore is unable to exert significant control over when peak demand occurs, an average of contributions to Resource Pool peaks occurring in November, December, July, June, August, and September (the six months with highest peak values) was used for allocating costs. GDS believes that this allocation factor is more appropriate than an allocation factor based on the average of all month's coincident loads as used in the 2014 study as system peaks occurring in spring and fall are unlikely to be relevant due to the use of the demand ratchet within the pool.

As Residential load peaks generally occur later in the day than the overall system peak, the use of the Resource Pool coincident demand results in significantly different results than under a more common retail system coincident methodology. The effect of using contributions to Resource Pool coincident demands rather than a more common 6CP (average of contributions to the six highest monthly peaks) allocation factor is shown in Table 28.

Table 28 - Result of Resource Pool Coincident Peak Allocation Methodology

	6CP kW Allocation Methodology		Resource Pool Coincident Allocation Methodology		Difference due to Methodology	
	%	$	%	$	%	$
Residential	62.6%	$ 2,187,814	54.2%	$ 1,894,663	-8.4%	$ (293,151)
Small Commercial	7.8%	273,608	8.6%	299,182	0.7%	25,574
Small County	0.6%	19,540	0.3%	10,967	-0.2%	(8,573)
Small School	0.5%	17,504	0.9%	31,493	0.4%	13,989
Large Commercial	16.0%	560,363	21.4%	749,780	5.4%	189,417
Large County	10.6%	368,925	11.0%	383,737	0.4%	14,811
Large School	1.7%	60,028	3.5%	123,567	1.8%	63,538
Street/Traffic Lighting	0.2%	8,624	0.1%	3,201	-0.2%	(5,423)
Area Lighting	0.0%	-	0.0%	-	0.0%	-
Total	**100.0%**	**$ 3,496,406**	**100.0%**	**$ 3,496,588**	**0.0%**	**$ 0**

The allocations of demand-classified Resource Pool costs to customers utilized for purposes of assessing total cost of service and rate design is shown in Table 29.

Table 29 - Allocation of Resource Pool Demand-Related Costs

	Allocation				
Rate Class	**RP 6CP kW**	**Allocation**	**Total $**	**Customers**	**Average $/Cust./Month**
Residential	9,271	54%	$ 1,894,663	8,876	$ 17.79
Small Commercial	1,464	9%	299,182	663	37.60
Small County	54	0%	10,967	117	7.81
Small School	154	1%	31,493	51	51.46
Large Commercial	3,669	21%	749,780	56	1,115.74
Large County	1,878	11%	383,737	18	1,776.56
Large School	605	4%	123,567	13	792.09
Street/Traffic Lighting	15	0%	3,201	64	4.17
Area Lighting	-	0%	-	167	-
Total	**17,108**	**100%**	**$ 3,496,588**	**10,025**	**$ 29.07**

9.5.2.2 Allocation of Resource Pool Energy-Related Costs

Determination of the allocation of energy- or commodity-related costs is made based on each class's total consumption. This allocation methodology is standard for energy-related costs. This study considered performing the allocation of individual month costs based on usage within that month to better reflect class-specific energy consumption patterns and monthly variations in electric costs but deemed it inappropriate given the forward-looking nature of the test year and the potential for non-representative changes in power costs in historical data.

Table 30 - Allocation of Resouce Pool Energy-Related Costs

Rate Class	Allocation Energy	Allocation		Total $	Customers		Average $/Cust./Month
Residential	58,795,076	50%	$	2,339,489	8,876	$	21.96
Small Commercial	13,333,056	11%		530,530	663		66.68
Small County	2,406,513	2%		95,756	117		68.20
Small School	993,884	1%		39,547	51		64.62
Large Commercial	22,664,862	19%		901,847	56		1,342.03
Large County	13,769,291	12%		547,888	18		2,536.52
Large School	3,712,919	3%		147,739	13		947.05
Street/Traffic Lighting	806,754	1%		32,101	64		41.80
Area Lighting	2,892	0%		115	167		0.06
Total	**116,485,247**	**100%**	**$**	**4,635,012**	**10,025**	**$**	**38.53**

9.5.3 Allocation of Distribution System Costs

Distribution system costs were previously split into those considered demand-related and those considered customer-related. This was based on the concept that the system can be split into two main functions – those required to provide basic service (customer-related) and those required to meet demand at times when the system experiences highest levels of load (demand-related). The allocation of these costs follows the same logic. Customer-related costs are allocated based on the presence of a service location, and demand costs are allocated based on the maximum load placed on the system by an individual customer class, also referred to as non-coincident peak load. These allocations are shown in Tables 31 and 32.

Table 31 - Allocation of Distribution System Customer-Related Costs

Rate Class	Allocation Bills	Allocation		Total $	Customers		Average $/Cust./Month
Residential	106,512	89%	$	1,243,294	8,876	$	11.67
Small Commercial	7,956	7%		92,869	663		11.67
Small County	1,404	1%		16,389	117		11.67
Small School	612	1%		7,144	51		11.67
Large Commercial	672	1%		7,844	56		11.67
Large County	216	0%		2,521	18		11.67
Large School	156	0%		1,821	13		11.67
Street/Traffic Lighting	768	1%		8,965	64		11.67
Area Lighting	820	1%		9,576	68		11.67
Total	**119,116**	**100%**	**$**	**1,390,423**	**9,926**	**$**	**11.67**

Table 32 - Allocation of Distribution System Demand-Related Costs

Rate Class	Allocation NCP kW	Allocation		Total $	Customers		Average $/Cust./Month
Residential	13,538	52%	$	1,071,471	8,876	$	10.06
Small Commercial	2,449	9%		193,806	663		24.36
Small County	235	1%		18,609	117		13.25
Small School	249	1%		19,736	51		32.25
Large Commercial	4,542	17%		359,478	56		534.94
Large County	3,311	13%		262,092	18		1,213.39
Large School	1,601	6%		126,704	13		812.20
Street/Traffic Lighting	137	1%		10,817	64		14.08
Area Lighting	59	0%		4,708	167		2.35
Total	**26,121**	**100%**	**$**	**2,067,420**	**10,025**	**$**	**17.19**

9.5.4 Allocation of Metering, Customer Service and Billing Costs

Customer-classified costs are allocated using two separate factors. Customer service and billing costs are assigned based on the number of customers in each rate class. The allocation of metering costs is made on a weighted meter factor that accounts for the average installation cost of meters for each rate class, which is assumed to approximate the cost of maintaining the meters. Area lights are unmetered and do not receive any metering costs.

Table 33 - Allocation of Billing and Customer Service Costs

Rate Class	Allocation Bills	Allocation		Total $	Customers		Average $/Cust./Month
Residential	106,512	89%	$	1,767,235	8,876	$	16.59
Small Commercial	7,956	7%		132,005	663		16.59
Small County	1,404	1%		23,295	117		16.59
Small School	612	1%		10,154	51		16.59
Large Commercial	672	1%		11,150	56		16.59
Large County	216	0%		3,584	18		16.59
Large School	156	0%		2,588	13		16.59
Street/Traffic Lighting	768	1%		12,743	64		16.59
Area Lighting	820	1%		13,612	68		16.59
Total	**119,116**	**100%**	**$**	**1,976,366**	**9,926**	**$**	**16.59**

Table 34 - Allocation of Meter Related Costs

Rate Class	Allocation Bills	Allocation		Total $	Customers		Average $/Cust./Month
Residential	106,512	89%	$	179,983	8,876	$	1.69
Small Commercial	7,956	7%		26,575	663		3.34
Small County	1,404	1%		4,999	117		3.56
Small School	612	1%		1,902	51		3.11
Large Commercial	672	1%		2,611	56		3.88
Large County	216	0%		1,144	18		5.30
Large School	156	0%		627	13		4.02
Street/Traffic Lighting	768	1%		1,332	64		1.73
Area Lighting	820	1%		-	68		-
Total	**119,116**	**100%**	**$**	**219,172**	**9,926**	**$**	**1.84**

9.5.5 Allocation of Directly Incurred Area Lighting Costs

LAC separately accounts for costs that are directly incurred to serve area lighting customers. These costs have been directly assigned to that rate class as shown in Table 35.

Table 35 - Allocation of Area Lighting Costs

Rate Class	Allocation Area Lighting	Allocation	Total $	Customers	Average $/Cust./Month
Residential	-	0%	$ -	8,876	$ -
Small Commercial	-	0%	-	663	-
Small County	-	0%	-	117	-
Small School	-	0%	-	51	-
Large Commercial	-	0%	-	56	-
Large County	-	0%	-	18	-
Large School	-	0%	-	13	-
Street/Traffic Lighting	-	0%	-	64	-
Area Lighting	1	100%	4,312	68	5.26
Total	**1**	**100%**	**$ 4,312**	**9,926**	**$ 0.04**

9.5.6 Allocation of Debt Service Costs

The allocation of debt service costs is made on an analysis of distribution plant assets in service. Gross investment in substation, distribution lines, transformers, meters, and services was reviewed and split using the same classification methods as distribution operations and maintenance costs. Allocating debt on the plant in service is deemed appropriate, versus assigning specific debt issues based on the type of plant funded by that debt, as the cost of debt would shift as payments were made and debt was issued. The utility must fund construction of all plant, even if that construction occurs at different times.

Table 36 - Allocation of Debt Service Costs

Rate Class	Allocation Dist. Plt.	Allocation	Total $	Customers	Average $/Cust./Month
Residential	$ 29,463,301	69%	$ 751,738	8,876	$ 7.06
Small Commercial	3,593,999	8%	91,699	663	11.53
Small County	459,181	1%	11,716	117	8.34
Small School	330,310	1%	8,428	51	13.77
Large Commercial	4,209,696	10%	107,408	56	159.83
Large County	3,022,595	7%	77,120	18	357.04
Large School	1,469,480	3%	37,493	13	240.34
Street/Traffic Lighting	247,870	1%	6,324	64	8.23
Area Lighting	176,171	0%	4,495	68	5.48
Total	**$ 42,972,603**	**100%**	**$ 1,096,420**	**9,926**	**$ 9.20**

9.5.7 Allocation of Revenue-Related Costs

LAC pays franchise fees and transfers a portion of revenues to the general fund. These amounts are determined as a percentage of revenues collected from residential, commercial, and area lighting customers. For purposes of the cost of service, these costs have been allocated to those customer classes based on the total allocation of non-revenue related costs described above.

Table 37 - Allocation of Revenue-Related Costs

Rate Class	Allocation Direct Costs	Allocation	Total $	Customers	Average $/Cust./Month
Residential	$ 9,247,872	72%	$ 937,978	8,876	$ 8.81
Small Commercial	1,366,665	11%	138,616	663	17.42
Small County	-	0%	-	117	-
Small School	-	0%	-	51	-
Large Commercial	2,140,117	17%	217,064	56	323.01
Large County	-	0%	-	18	-
Large School	-	0%	-	13	-
Street/Traffic Lighting	-	0%	-	64	-
Area Lighting	36,819	0%	3,734	68	4.55
Total	**$ 12,791,473**	**100%**	**$ 1,297,392**	**9,926**	**$ 10.89**

9.6 Total Cost of Service and Comparison to Current Rates

The allocation of the total cost of service is shown in Tables 38 and 39 as both the total cost of serving the class by component, and the average cost of serving a customer within a given class.

Table 38 - Total Cost of Service by Customer Class

		Production		Distribution				Cust. Service		
Rate Class	**Total**	Demand	Energy	Demand	Customer	Metering	Lighting	**and Billing**	**Debt**	**Revenue**
Residential	$ 9,983,941	$ 1,894,663	$ 2,339,489	$ 1,071,471	$ 1,243,294	$ 179,983	$ -	$ 1,767,235	$ 751,738	$ 736,069
Small Commercial	1,475,442	299,182	530,530	193,806	92,869	26,575	-	132,005	91,699	108,777
Small County	177,763	10,967	95,756	18,609	16,389	4,999	-	23,295	11,716	(3,968)
Small School	115,818	31,493	39,547	19,736	7,144	1,902	-	10,154	8,428	(2,585)
Large Commercial	2,310,456	749,780	901,847	359,478	7,844	2,611	-	11,150	107,408	170,339
Large County	1,250,181	383,737	547,888	262,092	2,521	1,144	-	3,584	77,120	(27,904)
Large School	430,920	123,567	147,739	126,704	1,821	627	-	2,588	37,493	(9,618)
Street/Traffic Lighting	73,835	3,201	32,101	10,817	8,965	1,332	-	12,743	6,324	(1,648)
Area Lighting	39,749	-	115	4,708	9,576	-	4,312	13,612	4,495	2,931
Total	**$ 15,858,105**	**$ 3,496,588**	**$ 4,635,012**	**$ 2,067,420**	**$ 1,390,423**	**$ 219,172**	**$ 4,312**	**$ 1,976,366**	**$ 1,096,420**	**$ 972,392**
% of Total	100%	19%	23%	11%	12%	2%	0%	18%	8%	7%

Table 39 - Total Average Cost of Service per Customer per Month

		Production		Distribution				Cust. Service		
Rate Class	**Total**	Demand	Energy	Demand	Customer	Metering	Lighting	**and Billing**	**Debt**	**Revenue**
Residential	$ 93.74	$ 17.79	$ 21.96	$ 10.06	$ 11.67	$ 1.69	$ -	$ 16.59	$ 7.06	$ 6.91
Small Commercial	185.45	37.60	66.68	24.36	11.67	3.34	-	16.59	11.53	13.67
Small County	126.61	7.81	68.20	13.25	11.67	3.56	-	16.59	8.34	(2.83)
Small School	189.25	51.46	64.62	32.25	11.67	3.11	-	16.59	13.77	(4.22)
Large Commercial	3,438.18	1,115.74	1,342.03	534.94	11.67	3.88	-	16.59	159.83	253.48
Large County	5,787.88	1,776.56	2,536.52	1,213.39	11.67	5.30	-	16.59	357.04	(129.19)
Large School	2,762.31	792.09	947.05	812.20	11.67	4.02	-	16.59	240.34	(61.66)
Street/Traffic Lighting	96.14	4.17	41.80	14.08	11.67	1.73	-	16.59	8.23	(2.15)
Area Lighting	48.45	-	0.14	5.74	11.67	-	5.26	16.59	5.48	3.57
Total	**$ 12,727.99**	**$ 3,803.23**	**$ 5,089.01**	**$ 2,660.27**	**$ 105.06**	**$ 26.63**	**$ 5.26**	**$ 149.33**	**$ 811.62**	**$ 77.60**

It should be noted that the "average" customer's costs are not necessarily indicative of the cost of serving the median customer within that class as distortions can occur, particularly within less homogeneous rate classes.

Table 40 presents the cost of service (projected Fiscal Year 2025) against the revenues that will be collected through rates for each class. The amount of over- or under-recovery for each class is also shown on a levelized basis, which represents the results if all rates were adjusted proportionally so that the exact cost of service was being collected. Levelized rates present a better point of comparison as the overall revenue requirement does not include any additional cost for recovery of reserve balances which will require the utility to collect additional revenues above the strict cost of service.

Table 40 - Cost of Service and Revenue Recovery

Rate Class	Cost of Service (FY25)	Revenues (July 2024)	Under/(Over) Recovery $	Under/(Over) Recovery %	Under/(Over) Recovery Levelized $	Under/(Over) Recovery Levelized %
Residential	$ 9,983,941	$ 9,649,795	$ (334,146)	-3%	$ (1,057,883)	-11%
Small Commercial	1,475,442	1,985,079	509,637	35%	360,756	24%
Small County	177,763	366,456	188,694	106%	161,210	91%
Small School	115,818	145,926	30,108	26%	19,164	17%
Large Commercial	2,310,456	3,080,877	770,421	33%	539,354	23%
Large County	1,250,181	1,337,557	87,376	7%	(12,941)	-1%
Large School	430,920	444,427	13,507	3%	(19,825)	-5%
Street/Traffic Lighting	73,835	117,441	43,606	59%	34,798	47%
Area Lighting	39,749	16,343	(23,406)	-59%	(24,632)	-62%
Total	**$ 15,858,105**	**$ 17,143,903**	**$ 1,285,798**	**8%**	**$ -**	**0%**

While some individual class under- and over-recoveries appear large, it is important to remember that a number of classes are made up of a small number of customers, or in the case of the County rate class, a single customer. Therefore, total subsidies paid by these classes may be consolidated to give a better picture of overall cost recovery. Consolidation of the County and School rate classes results in the following:

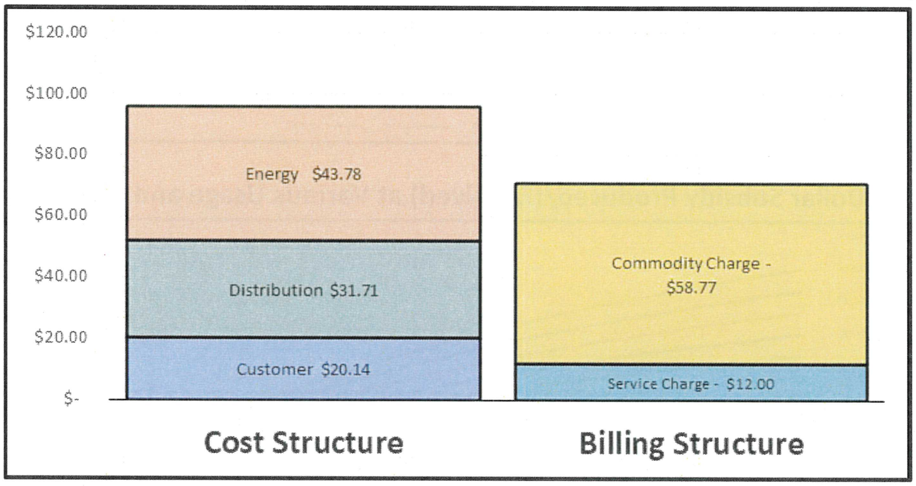
Table 41 - Cost of Service and Revenue Recovery (Consolidated Classes)

	Cost of Service (FY25)	Revenues (July 2024)	Under/(Over) Recovery $	Under/(Over) Recovery %	Under/(Over) Recovery Levelized $	Under/(Over) Recovery Levelized %
Residential	$ 9,983,941	$ 9,649,795	$ (334,146)	-3%	$ (1,057,883)	-11%
Small Commercial	1,475,442	1,985,079	509,637	35%	360,756	24%
Large Commercial	2,310,456	3,080,877	770,421	33%	539,354	23%
County	1,501,778	1,821,455	319,676	21%	183,067	12%
School	546,738	590,353	43,615	8%	(662)	0%
Area Lighting	39,749	16,343	(23,406)	-59%	(24,632)	-62%
Total	**$ 15,858,105**	**$ 17,143,903**	**$ 1,285,798**	**8%**	**$ -**	**0%**

9.6.1 Residential Customers

Under current rates approved in October 2023, residential customers under-recover their cost of service by approximately 3%, roughly in line with the total under-recovery at the utility level. The cost recovery for the average customer under current rates is shown in Figure 29. While Energy, Distribution, and Customer-functionalized costs are not immediately translatable into rates, they can be compared to fixed (service) and variable (commodity) charges to provide an illustration of how the cost structure compares to the revenue structure.

Figure 29 - Residential Cost and Recovery Structure (Average Customer)



Current service charges of $12.00 per bill are below the $16.59 incurred per customer for metering, customer service and billing activities and are significantly below the total fixed costs of service of $20.14. This is not unusual as residential service charges are set at a level where service is affordable.

Subsidies in Residential Rates

Two primary subsidies occur in current residential rates. The first subsidy is due to total fixed costs not being recovered in fixed charges, resulting in customers with higher usage subsidizing those with lower usage. The second subsidy occurs due to differences in load factor.

A customer's load factor refers to the relationship between the maximum demand in a period and the average demand over that period (*i.e.* usage). To calculate the load factor, the usage is divided by the maximum demand value, with a higher load factor representing a lower relative maximum demand factor.

Understanding load factor is essential when assessing subsidies present in current rates. As discussed above, for COSS purposes costs are identified as energy-, demand-, and customer-related. The residential rate only includes fixed and energy elements, therefore there will be a subsidy at the customer level based on the deviation from the average load factor of the class.

Customers with usage over 500 kWh may pay subsidies at higher load factors and receive a subsidy at lower load factors, with the point at which a customer begins to receive a subsidy occurring at lower load factors as usage increases.

Figure 30 - Percentage Subsidy Produced/(Received) at Various Usage and Load Factor Levels

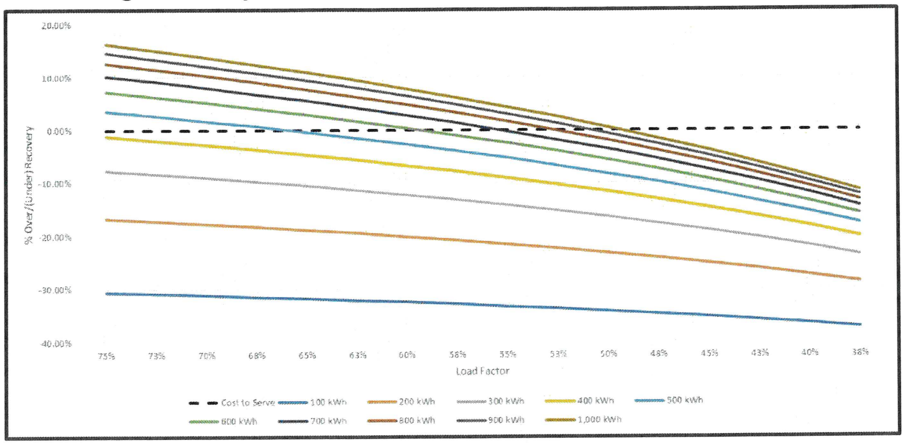
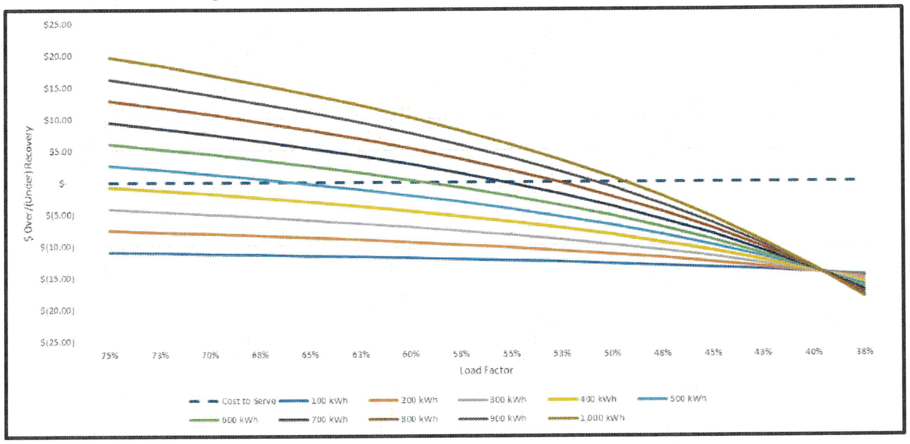


Figure 31 - Dollar Subsidy Produced/(Received) at Various Usage and Load Factor Levels



The relationship between recovery and cost causation shown in Figures 30 and 31 highlights the users that will be negatively affected by changes to rate design to reflect cost causation more accurately. All customers with usage at or under 400 kWh and larger customers at increasingly low levels of load factor would see bill increases if rates perfectly reflected underlying costs, and larger customers with high load factors would see decreases in bills. Relative increase to customer charges will decrease the subsidy provided to lower usage customers but will increase the subsidy given to customers with low load factors.

While the above presents a simple picture of intra-class subsidies for residential customers, it is important to remember that each customer will have a different level of usage, demand, and load factors throughout the year, and that these fluctuations may cause customers to receive a subsidy in some months while providing a subsidy in others, without even accounting for monthly and annual variations in underlying costs to provide service. Table 42 illustrates the cost to serve and the revenue recovered from a residential customer using an average of 573 kWh over the year at current rates.

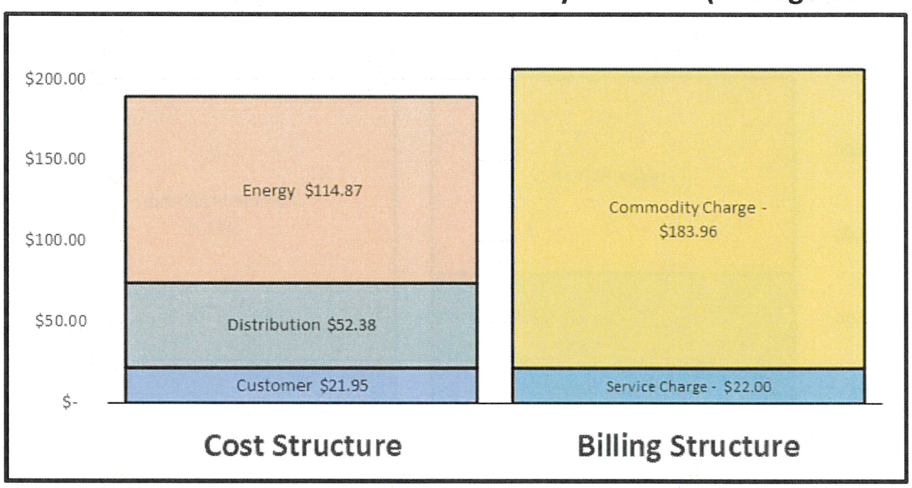
Table 42 - Illustrative Change of Monthly Subsidy Paid/(Received)

	Usage (kWh)	Demand kW	Cost to Serve	Rate Recovery	Subsidy Paid/(Received)
January	665	1.54	$ 96.13	$ 97.25	$ 1.12
February	614	1.42	93.26	90.71	(2.55)
March	611	1.41	93.10	90.33	(2.77)
April	464	1.07	84.82	71.48	(13.34)
May	466	1.08	84.94	71.74	(13.20)
June	560	1.30	90.23	83.79	(6.44)
July	592	1.37	92.03	87.89	(4.14)
August	571	1.32	90.84	85.20	(5.64)
September	587	1.36	91.75	87.25	(4.50)
October	464	1.07	84.82	71.48	(13.34)
November	596	1.38	92.25	88.41	(3.84)
December	683	1.58	97.15	99.56	2.41
Total	**6,873**		**$ 1,091.32**	**$ 1,025.12**	**$ (66.20)**
	Maximum Demand kW:	1.58			
	Annual Load Factor:	0.50			

9.6.1.1 Small Commercial Customers

While the Small Commercial rate class revenues exceed its cost of service, it must be kept in mind that this comparison does not include any additional contingency funding or additional funds to help reserves recover. Overall, rates paid by small commercial customers are generally acceptable when compared against the cost of service. The service charge is roughly comparable with the fixed costs incurred by the utility to provide service, minimizing concerns about intra-class subsidies being provided to low usage customers. However due to the relatively heterogenous nature of the class, load-factor related subsidies probably exceed those in the residential class.

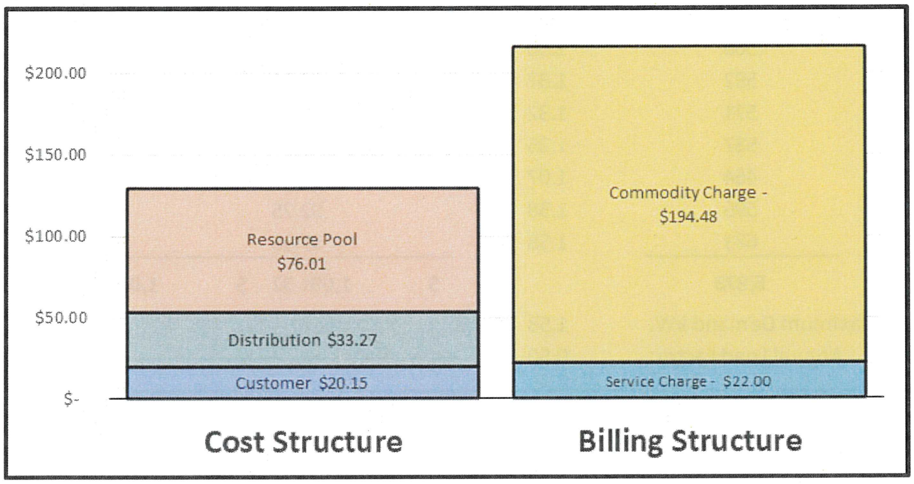
Figure 32 - Small Commercial Cost and Recovery Structure (Average Customer)



9.6.2 Small County Customers

The Small County rate class is paying significantly more than its cost of service, although this is offset largely by under-recovery at the Large County rate class, and thus is not a cause for concern. As with the small commercial customer class, the fixed charges appear appropriate for recovering the fixed costs of service.

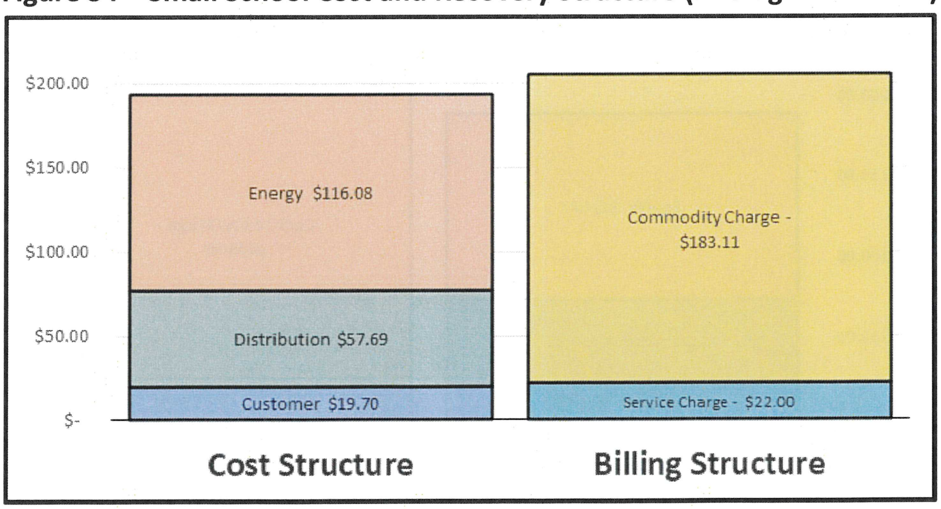
Figure 33 - Small County Cost and Recovery Structure (Average Customer)



9.6.3 Small School Customers

The Small School rate class is slightly over-recovering its cost of service, but not to the extent that it needs to be addressed in rate design. Much like the Small County rate class, concerns about subsidization may be lessened if the same customers are taking service under the large and small tariffs. Fixed charges appear appropriate given the cost of providing service.

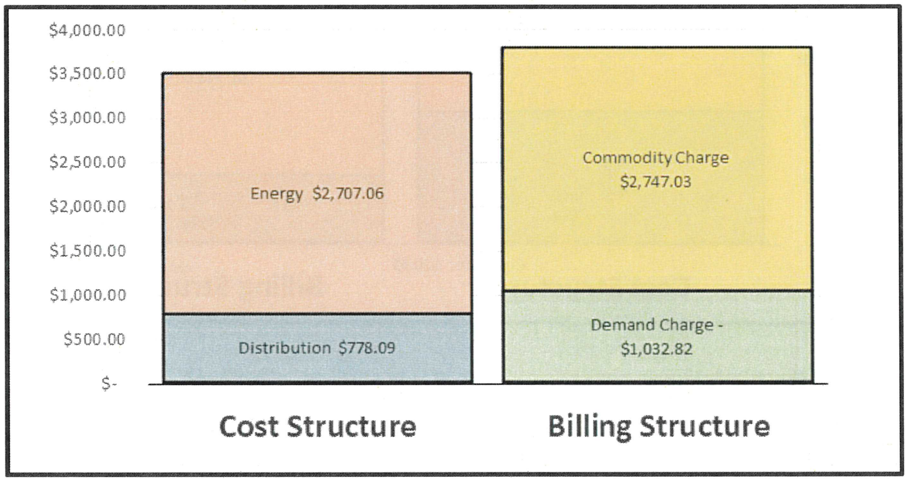
Figure 34 - Small School Cost and Recovery Structure (Average Customer)



9.6.4 Large Commercial Customers

The Large Commercial rate class is recovering very close to its cost of service. Service charges are slightly below the fixed costs of service, but both are immaterial given the average levels of consumption and demand for this class. Demand charges do not capture all demand-related costs, however the presence of a demand charge should incentivize users to maintain reasonable load factors, which should minimize the effect of any resulting intra-class subsidy.

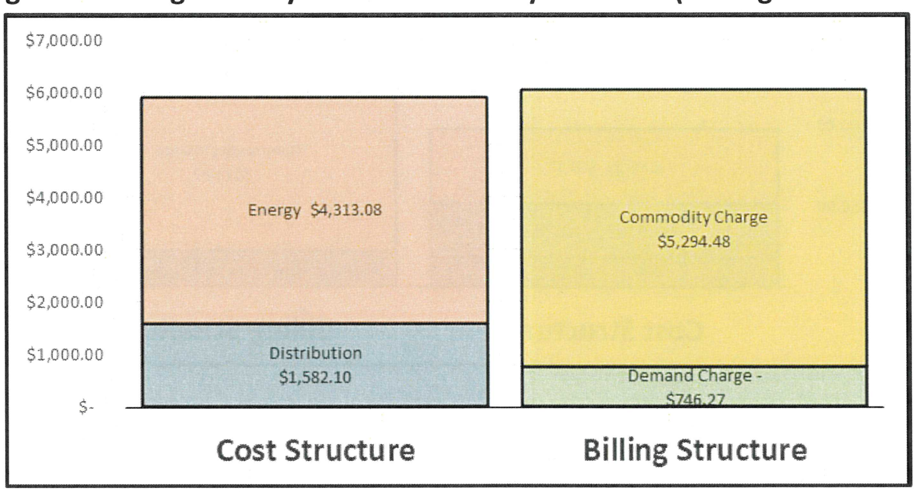
Figure 35 - Large Commercial Cost and Recovery Structure (Average Customer)



9.6.5 Large County Customers

The Large County rate class under-recovers total costs, but when viewed in context with all county-owned service locations, the amount of the overall subsidy is relatively small.

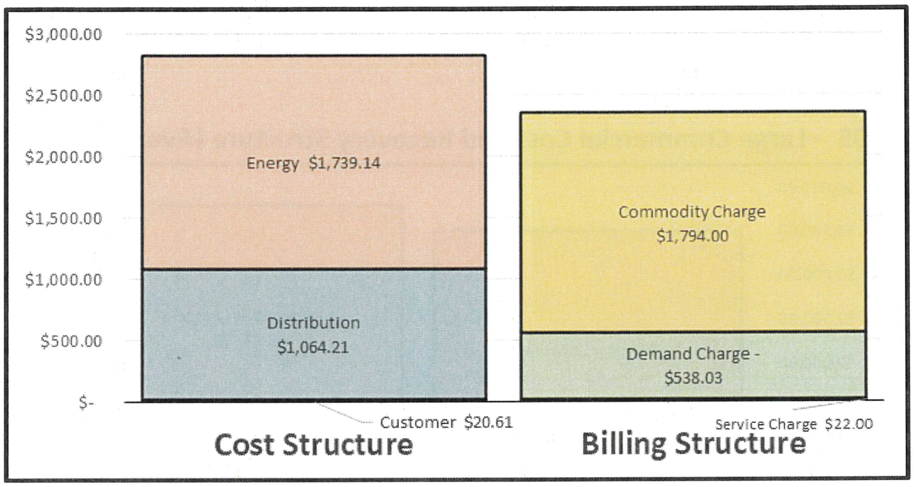
Figure 36 - Large County Cost and Recovery Structure (Average Customer)



9.6.6 Large School Customers

Similar to Large County ratepayers, the Large School class is under-recovering the cost of service, though not to the same extent. If the set of customers served in the large and small school classes are the same, there is little concern about overall levels of revenue recovery, as schools overall receive a very minor subsidy.

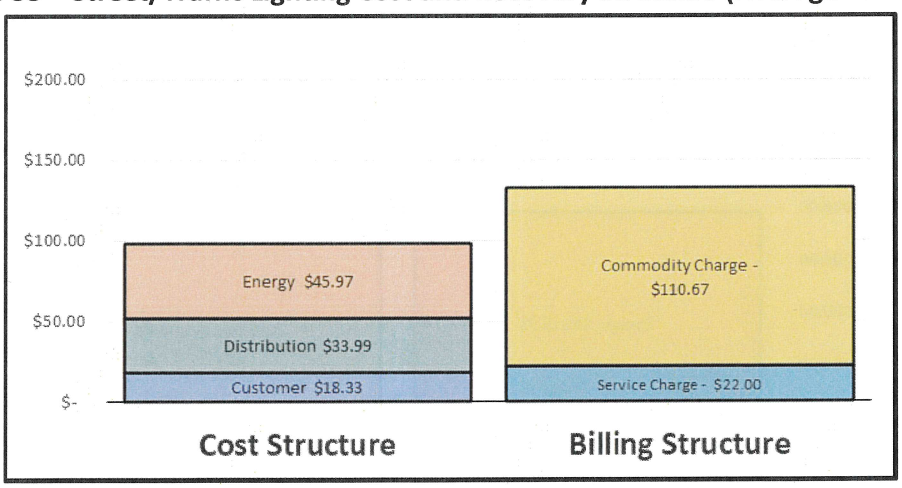
Figure 37 - Large School Cost and Recovery Structure (Average Customer)



9.6.7 Street/Traffic Lighting

While large proportional to the overall revenue requirement for the class, the over-recovery for this class should be considered in context of the relatively small overall revenue requirement and that the service is being provided to the county. Potential adjustments to this class are discussed in Section 12.

Figure 38 - Street/Traffic Lighting Cost and Recovery Structure (Average Customer)



9.6.8 Unmetered Area Lights

Revenues from the Unmetered Area Light customer class are recovered for each light, with higher charges for lights with larger rated output. The overall revenue requirement for this class is relatively low due to the lights not having an effect on most peak usage times, lack of metering, and the minimal demand created by the lights. An increase in area lighting rates may be appropriate given the level of under-recovery.

9.7 Discussion of COSS Results

At a high level, no inter-class subsidies exist that need immediate attention. Fixed charges for all classes other than the residential class are appropriate in that they recover the fixed costs of service. A relative reduction in the revenues collected from Small Commercial and Street/Traffic Lighting customers may be appropriate next time LAC is considering increasing rates, along with rebalancing of revenue recovery between the Large and Small classes for the County and School rate groups. Our recommendations as to changes that may be made to current rates can be found in Section 12.

10 General Principles of Rate Design

10.1 Approach to Rate Design Recommendations

The majority of potential issues raised in regard to LAC's current rates center around whether they are adequate to fairly apportion costs as the County experiences higher rates of adoption of distributed energy resources, energy storage devices, and electrification. When rates were last set, it was assumed that all customers within a rate class, such as Residential, had generally homogeneous patterns of consumption, but accelerating adoption of new technologies and the unique stresses they place on the system require review of rates to ensure cost recovery goals are being met.

The most referenced general objectives of rate design were set out by Dr. James Bonbright in *Principles of Public Utility Rates* (1961):

- Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation.
- Effectiveness of yielding total revenue requirements.
- Revenue (and cash flow) stability from year to year.
- Reflect present and future social costs.
- Fairness in apportioning cost of service.
- Avoidance of "undue discrimination."
- Promotion of efficient usage of electricity and competing products.

Achieving all objectives of rate design is impossible due to conflicts between objectives. Generally, utility experts and regulators focus on (1) rate simplicity, (2) revenue stability, (3) price signaling, with the objective of promoting efficient usage, and (4) general adherence to the cost-of-service results.

It is important to understand that while the cost of service is used to guide the rate design process, it is impossible to implement rates that exactly recover the cost of serving each class, which changes from moment to moment and for each individual customer. Rates are approximations of the cost of serving the "average" customer in each customer class in a specific period, and inter- and intra-class subsidies will always be present. As demonstrated in Bonbright's principles, ensuring rates fairly approximate the cost of service is only one of several objectives of utility rate design. Other rate design considerations apart from those promoted by Bonbright, such as policy objectives and avoidance of substantial bill impacts, may also be relevant in some situations.

10.1.1 Common Rate Design Approaches

Rate design varies from utility to utility and is guided by the ability of the utility to bill certain rates, the general objectives of rate design above, and inertia provided by previous ratemaking decisions. Under the most popular form of rate design, rates charged for electricity involve a fixed charge, a volumetric charge, and for some customer classes, a demand charge.

10.1.1.1 Fixed/Variable Rate Structure

From the point where electricity was widely available as a utility service and the widespread ability to measure consumption through meters existed, the most common rate design has consisted of a two-part design consisting of a fixed element[14] and a volumetric element based on the total number of kilowatt-hours consumed in a billing period. The simplest form of this design applies the same rate to all kWh consumed regardless of total usage. This design is popular for several reasons – it is easy to administer, allows customers to easily understand and predict what their utility bill will be, and can be roughly determined without the preparation of a cost-of-service study.

Residential and small commercial customer volumetric charges typically include a portion of demand and customer-related costs for two main reasons. First, as residential demand historically has not been able to be efficiently measured, usage levels were deemed to be the best available proxy for the demand a customer may place on the grid. Second, social policies generally deemed a lower fixed charge to be preferable to allow lower usage customers – which were viewed as a reliable proxy for low-income customers – to control utility costs. Recovery of more costs through the volumetric charge also had the benefit of raising the cost of consumption, allowing for more flexibility when designing rates with the goal of disincentivizing excess usage.

10.1.1.2 Demand Charges

Electric demand charges are based on the maximum amount of electricity demanded by a customer in a billing period and are commonly applied in large commercial and industrial rate structures. A demand charge nominally recovers those costs that have been designated as demand-related in the COSS, leading to better recognition of costs placed on the system by those customers. An inherent limitation of the fixed/variable rate structure is that demand-related costs must necessarily be recovered through either fixed or usage-based charges. While higher levels of usage generally correspond to higher levels of demand, each customer will have a unique load factor[15] that will result in distortions in intra-class cost recovery. This relationship is complicated by seasonal variations in demand, as the utility is unable to reduce its demand-related costs or investment during times of lower demand. A simple example of cost distortion inherent in fixed/variable demand rates is below[16] with additional details shown in Appendix C:

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[14] Referred to variously as a Customer, Fixed, Service, or meter charge.

[15] See Section 8.6.1.1.1 for further discussion of load factor and resulting subsidies.

[16] Costs and charges not representative of Los Alamos. In this instance, the customer is larger and has higher usage and a lower load factor than the class as a whole, and therefore receives a subsidy from other customers within the class.

Table 43 - Example of Subsidy Received Under Fixed/Varable Rate

	Customer Statistics			Cost Incurred by Utility				Cost Recovery - $5 Fixed Charge			Subsidy
	kWh	kW	Load Factor	Demand	Volumetric	Customer	Total	Fixed	Varable	Total	Received/(Paid)
January	1,006	5.25	0.53	$ 20.94	$ 50.30	$ 5.50	$ 76.74	$ 5.00	$ 49.52	$ 54.52	$ 22.22
Feburary	1,113	4.82	0.64	20.94	55.65	5.50	82.09	5.00	54.79	59.79	22.30
March	800	4.83	0.46	20.94	40.00	5.50	66.44	5.00	39.38	44.38	22.06
April	750	4.76	0.44	20.94	37.50	5.50	63.94	5.00	36.92	41.92	22.02
May	810	5.21	0.43	20.94	40.50	5.50	66.94	5.00	39.87	44.87	22.07
June	1,100	6.18	0.49	20.94	55.00	5.50	81.44	5.00	54.15	59.15	22.29
July	1,250	6.87	0.51	20.94	62.50	5.50	88.94	5.00	61.53	66.53	22.41
August	1,506	6.98	0.60	20.94	75.30	5.50	101.74	5.00	74.13	79.13	22.61
September	1,174	6.87	0.47	20.94	58.70	5.50	85.14	5.00	57.79	62.79	22.35
October	859	5.55	0.43	20.94	42.95	5.50	69.39	5.00	42.28	47.28	22.11
November	782	5.36	0.41	20.94	39.10	5.50	65.54	5.00	38.49	43.49	22.05
December	948	5.27	0.50	20.94	47.40	5.50	73.84	5.00	46.66	51.66	22.18
Total	**12,098**			**$ 251.28**	**$ 604.90**	**$ 66.00**	**$ 922.18**	**$ 60.00**	**$ 595.52**	**$ 655.52**	**$ 266.66**

Although this distortion is inherent in fixed/volumetric rates, rate classes with more homogeneous usage and demand characteristics are less susceptible. In smaller rate classes that tended towards relatively more heterogenous demand and consumption patterns (*e.g.* large commercial, industrial), subsidization concerns were elevated, and a solution was needed.

Popular solutions include categorizing customers into more homogeneous rate classes (defining rate classes by usage levels, or penalizing certain load factors), charging customers on demand characteristics, or a combination of the two. Often the combination would take the form of separating non-residential customers into separate classes depending on levels of usage. "Large" customer groups, typically relatively small populations with very different demand characteristics, would have meters capable of measuring demand and would be billed on demand to reduce intra-class subsidies. As shown below, demand charges have the potential to greatly reduce concerns about intra-class subsidies if proper design can be achieved.

Table 44 - Example of Subsidy with Added Demand Charge

	Customer Statistics			Cost Incurred by Utility				Billed - $5 Fixed Charge, $2.75 Demand Charge				Subsidy
	kWh	kW	Load Factor	Demand	Volumetric	Customer	Total	Fixed	Demand	Varable	Total	Received/(Paid)
January	1,006	5.25	0.53	$ 20.94	$ 50.30	$ 5.50	$ 76.74	$ 5.00	$ 22.69	$ 50.32	$ 78.01	$ (1.27)
Feburary	1,113	4.82	0.64	20.94	55.65	5.50	82.09	5.00	22.69	55.67	83.36	(1.27)
March	800	4.83	0.46	20.94	40.00	5.50	66.44	5.00	22.69	40.02	67.70	(1.26)
April	750	4.76	0.44	20.94	37.50	5.50	63.94	5.00	22.69	37.52	65.20	(1.26)
May	810	5.21	0.43	20.94	40.50	5.50	66.94	5.00	22.69	40.52	68.20	(1.26)
June	1,100	6.18	0.49	20.94	55.00	5.50	81.44	5.00	22.69	55.02	82.71	(1.27)
July	1,250	6.87	0.51	20.94	62.50	5.50	88.94	5.00	22.69	62.53	90.21	(1.27)
August	1,506	6.98	0.60	20.94	75.30	5.50	101.74	5.00	22.69	75.33	103.02	(1.28)
September	1,174	6.87	0.47	20.94	58.70	5.50	85.14	5.00	22.69	58.73	86.41	(1.27)
October	859	5.55	0.43	20.94	42.95	5.50	69.39	5.00	22.69	42.97	70.65	(1.26)
November	782	5.36	0.41	20.94	39.10	5.50	65.54	5.00	22.69	39.12	66.80	(1.26)
December	948	5.27	0.50	20.94	47.40	5.50	73.84	5.00	22.69	47.42	75.11	(1.27)
Total	**12,098**			**$ 251.28**	**$ 604.90**	**$ 66.00**	**$ 922.18**	**$ 60.00**	**$ 272.22**	**$ 605.16**	**$ 937.38**	**$ (15.20)**

The extension of demand-based rates to residential and smaller commercial customers remained rare throughout the United States through the mid-2010s due to the relative perceived homogeneity of those classes, additional costs that would be incurred to install demand meters, and inability of billing systems to bill demand rates. Three main factors have led to more general consideration of whether demand charges may be appropriate for these customers.

The first factor is the introduction of AMI meters, which allow for demand values to be reported in a cost-effective manner. As utilities look for ways to utilize their AMI systems, implementation of demand charges and time-of-use options are often explored. AMI technology has also provided additional insight into the levels of subsidy that may be occurring in these rate classes despite the previously assumed general homogeneity of these customers.

The second is the general rise in the price of electricity. As the cost of service increases due to inflationary and other pressures, regulatory bodies and rate design experts have sought ways to limit the effect of those increases on vulnerable and low-usage customers. Disaggregation of demand, energy, and customer-related costs into separate charges provides an avenue to apportion the costs of service and reduce subsidies between customers, potentially allowing low-usage customers to more fairly avoid a portion of costs that would otherwise be paid through fixed charges.

The third factor is the rise of distributed generation and DER. For utilities that allow customers to self-generate, locations with DER will consume less energy from the utility, reducing recovery of demand-related costs. As the utility must be prepared to provide service in case of DER unavailability or failure, the demand-related costs of serving the customer remain the same. Demand charges are seen as a mechanism to ensure that demand costs continue to be recovered from these customers, ensuring that these demand-related costs are not borne by other customers. Further discussion of the mechanisms underpinning the subsidization of DER customers can be found in Section 15.

10.1.2 The Impact of Advanced Metering Infrastructure Technology

AMI technology has become common over the past 20 years, with widespread installation of meters that automatically record and transmit real-time or periodical information to information technology systems maintained by the utility or their service provider. This allows the utility to better monitor system conditions, including outages, and provides information on sizing of future investments in the distribution system. Customers likewise can benefit from a better understanding of their usage patterns, monitor, or modify usage to avoid high bills, and participate in demand reduction programs.

AMI meters also bring benefits to the rate study and rate design process. Class demand and usage pattern data is now available in almost overwhelming quantities, supporting more accurate allocations of demand-related costs. Design of rates that rely on monthly, hourly, or real time usage and demand are also possible, allowing for better price signaling to customers and better apportionment of costs between customer classes.

10.1.3 Low- and Fixed-Income Customer Considerations

Low- and fixed-income customers are often thought of as being lower usage due to financial pressure to reduce the cost of utilities. While it is true that higher energy usage is observed on average as income increases, low- and fixed- income customers may live in structures and use household appliances that are less efficient, such as portable electric heaters and individual air conditioning units. Conversely, higher income customers who have invested in energy efficiency have lower amounts of consumption. The effect of these elements may be increased in climates where significant energy is consumed to manage heating and cooling of residences. Due to lower overall efficiency, low- and fixed- income customers may also have less control over the timing and extent of demand peaks.

Due to this dynamic, caution must be taken when considering the effect of current and proposed rates on low- and fixed-income customers. Shifting recovery of costs from fixed to volumetric charges may benefit some low- or fixed- income customers but harm others. While the overall affordability of electricity is a consideration when designing rates, in many cases targeted programs may achieve more savings for low-income customers. This may be especially true in areas such as Los Alamos where the percentage of the population living below the poverty line is significantly below the national average. In many cases these programs may also benefit the utility and other ratepayers by providing reductions in peak demand and decreased levels of usage in periods of high energy prices. While the development of low-income programs is outside the scope of a rate study and is subject to policy and legal considerations, some examples include direct assistance (such as Los Alamos' Utilities Assistance Program, based on voluntary direct donations), and subsidization of energy efficiency related upgrades.

11 Effect of Resource Pool Allocation on Rate Design

Participation in the Resource Pool allows LAC to access power at a significantly lower cost than if it were a standalone utility and is beneficial to LAC ratepayers. Based on our review of LAC's cost structure relative to benchmark utilities, we believe it is a critical component in being able to provide cost competitive services to utility customers. Despite these clear benefits, aspects of how costs are allocated within the Resource Pool affect typical approaches taken to reduce costs incurred by the utility and pass those savings on to customers. The first effect of the power pool relates to the relative size of the participants and the ability of LAC to control overall costs of the pool. The second relates to the allocation of these costs to pool participants.

11.1 Allocation of Costs within Resource Pool

11.1.1 Demand-Related Cost Allocation

LAC's usage and contribution to peak demand may make up between 15% and 30% of the total within the pool in each month. Due to relative size of participants, LAC retail customers may be unable to influence when demand peaks occur. While both the pool and LAC are typically summer peaking, LAC retail demand peaks rarely occur on the same day as the overall system peak and these peaks are even more unlikely to occur within the same hour. As a result, targeting specific times to reduce peak demand at the retail level may not reduce the costs incurred by the pool or the amount of cost allocated to retail customers.

Due to the 12-month lookback period used to determine the demand value used in the allocation between Resource Pool participants, demand costs will only be reduced to the extent that they result in reductions to the utility's demand in the month in which the utility had the highest contribution to the Resource Pool's peak load. Attempts to shift demand to reduce demand at the distribution level (such as moving summer demand earlier in the afternoon) may result in higher allocations of demand costs to LAC retail customers if the load at the time of the system peak is increased.

11.1.2 Energy-Related Cost Allocation

For energy related costs, which represent 60% of cost of generation and purchased power, LAC is exposed to the average cost per kWh in each month as total costs are allocated based on total kWh, of which LAC typically represents 19% and 28%, respectively, of pool usage. Shifting usage to try to capture times when lower cost resources are available may reduce the total cost of power, but these benefits will be shared between pool participants in proportion to their contribution to total usage. This mechanism complicates time-based rate design, which typically incentivize customers to change consumption patterns based on passing through the realized savings.

12 Recommended Changes to Current Rates

Based on the results of the COSS, GDS recommends the following adjustments if LAC does not move forward with the adoption of a different rate structure. While subsidies exist, we do not think the changes below are immediately necessary and recommend that they be considered in concert with the overall revenue needs of the utility the next time LAC contemplates changing rates. As the COSS is only an approximation and future variations in demand patterns, utility operations, and relative levels of growth between classes will cause certain classes to over- or under-recover each year, we do not recommend changes to classes that are reported to have relatively immaterial deviations from their cost of service.

12.1 Increase to Residential Fixed Charges

Service charges for residential customers do not cover the fixed costs of service. While we do not believe it is strictly necessary, an increase in the service charge to $14.00 would reduce subsidies within the class while still having overall small effects on low-usage customer bills. This change would also bring LAC's service charge closer to comparable utilities in the benchmark group.

12.2 Commercial Rate Classes Rate Adjustment

The Small Commercial and Large Commercial rate classes over-recover their cost of service indicated by the COSS. While some level of subsidization between commercial and residential customers is common in electric rate designs, the level under the current rates is relatively high — though not atypical — and steps should be taken to begin decreasing it. We recommend that this be done by reducing the level of recovery through usage charges proportional to total revenues collected from this class.

12.3 County Rates

The large over-recovery in the Small County rate class appears to be the result of many meters with relatively low levels of usage and demand present in the class. In previous rate studies, the demand and usage characteristics derived from a limited number of Commercial customers was applied to this class, overstating the cost of service. We recommend that the volumetric rate for this class not be increased during LAC's next rate review process in order to reduce the over-collection.

12.4 Street/Traffic Lighting Class

Street/Traffic Lighting is currently paying higher rates than necessary given the characteristics of the class. This class is unlikely to significantly contribute to system peak events, uses similar amounts of average energy to customers in the Small Commercial, Small County, and Small School classes, and tends to have good load factors. The 2014 rate study did not consider the Street/Traffic Lighting class separately from other County-owned facilities, instead assigning the class the same 11% increase as that given to private lighting and school customers — likely due to limitations on demand information in the study.

As a matter of equity, we do not believe that an adjustment is strictly necessary as the overall over-recovery at County-owned facilities is reasonable, however reducing the amount of subsidy now will ensure that it does not increase. Our recommended approach to eliminating the subsidy would be a reduction in the fixed charge, as the levels of demand and usage in this class are low in comparison to other customer classes.

12.5 Area Lighting

In relation to total utility revenues, the subsidy provided to Area Lighting customers is relatively small, despite it being high in relation to the class's cost of service. We do not recommend that Area Lighting rates be increased in the cost of service. This recommendation is based on the fact that area lights are generally co-located with other "primary" service locations, which reduces the incremental cost of distribution system needed to provide service. However, we recommend that any service being provided to individual customers in this class (such as changing out bulbs, etc.) be directly recovered through fees designed to cover the cost of all personnel, vehicle, or other resources needed to provide the service.

13 Alternative Rate Designs

13.1 Demand Rates

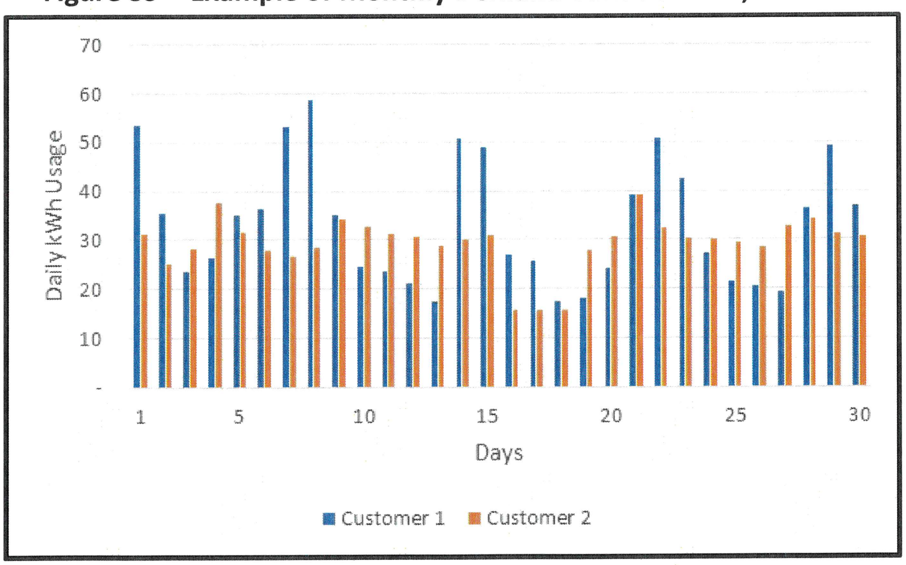
Until recently, the expense of meters capable of recording and reporting demand information made them uneconomical for installation on residential premises. The adoption of AMI meters has allowed utilities greater insight into residential demand patterns as well as enabling utilities to measure the demand at a specific location, making the system-wide adoption of demand rates possible.

13.1.1 Purpose of Demand Rates

Demand-based rates are sometimes considered to eliminate an inherent distortion in the fixed/variable rate structure. Specific investments and costs on the generation, transmission, and distribution systems are almost universally recognized to be related to the amount of peak demand that the system will experience, such as transmission charges and the sizing of distribution assets. Inclusion of demand-related costs in variable charges ultimately results in each customer paying for demand that would have occurred if usage was evenly spread across the period.

As an example, assuming a variable charge of $0.10 per kWh, of which 50% of which is demand-related, the utility will recover $50 of demand-related charges from each customer. However, despite having equal amounts of consumption, these customers may have radically different demand profiles, as shown in Figure 39.

Figure 39 - Example of Monthly Demand Variation at 1,000 kWh



In the above example, Customer 1 is much "peakier" than Customer 2 (e.g. has a lower load factor) and creates much higher levels of demand, and therefore should be assigned more demand cost. Assuming rates collect the total cost of service at the class level, charging both customers the same usage charge will result in Customer 1 being subsidized by Customer 2.

Demand rates, particularly when specific "on-peak" times are targeted for reduction, also may reduce load-related costs such as transmission charges, generation charges, and investment in distribution infrastructure.

LAC Management requested GDS investigate and propose a rate structure that includes demand charges. LAC had identified demand charges as a way of better recovering costs that customers with intermittent demand, specifically net metering customers, may cause but avoid paying for due to the current fixed/variable rate charge. Interest was also shown in the ability of demand rates to potentially decrease costs to the utility.

Ability of Demand Rates to Eliminate Intra-Class Subsidies

While demand rates represent a different approach to recovering costs, there is no guarantee that implementation of demand rates will result in the elimination of intra-class subsidies. While demand is not directly equivalent to usage, customers with higher usage levels tend to have higher demand, especially when demand is measured over hourly rather than 15-minute periods. Currently, larger than average residential users of electricity generally provide a subsidy to smaller customers, due to the amount of fixed cost recovered in volumetric charges. Without large increases in the service charge for all residential customers to recover these costs more accurately, the implementation of demand charges without a time element will result in shifting of subsidies, as shown in Table 45.

Table 45 - Implementation of Illustrative Demand Rate with $12.00 Customer Charge

	Customer 1	Customer 2	Customer 3	Customer 4	Customer 5
Avg Usage (kWh)	500	500	500	500	500
Maximum Demand (kW)	1.1	1.2	1.3	1.4	1.5
Load Factor	n/a	0.60	0.55	0.50	0.45
Rates - Current Structure at Cost of Service					
Customer Charge per Bill	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00
Usage Charge per kWh	0.1408	0.1408	0.1408	0.1408	0.1408
Rates - Demand					
Customer Charge per Bill	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00
Demand Charge per kW	33.62	33.62	33.62	33.62	33.62
Usage Charge per kWh	0.0493	0.0493	0.0493	0.0493	0.0493
Indicative Cost to Serve	$ 76.38	$ 78.20	$ 80.36	$ 82.94	$ 86.10
Current Structure					
Rate Recovery	82.38	82.38	82.38	82.38	82.38
Subsidy Paid/(Received) - $	6.00	4.17	2.02	(0.56)	(3.72)
Subsidy Paid/(Received) - % of Cost to Serve	8%	5%	3%	-1%	-4%
Demand Rates					
Rate Recovery	$ 72.59	$ 75.58	$ 79.12	$ 83.37	$ 88.56
Subsidy Paid/(Received) - $	$ (3.79)	$ (2.62)	$ (1.23)	$ 0.43	$ 2.46
Subsidy Paid/(Received) - % of Cost to Serve	-5%	-3%	-2%	1%	3%

Raising the customer charge in conjunction with demand charges can in some instances lower subsidies between customers, but it may not provide a more equitable benefit than would result from simply increasing fixed charges under current rates. This dynamic will continue until all fixed costs are recovered in fixed charges.

Table 46 - Comparison of Illustrative Demand Rate with $16.00 Customer Charge to Fixed/Variable Rate with $16.00 Customer Charge

	Customer 1	Customer 2	Customer 3	Customer 4	Customer 5
Avg Usage (kWh)	500	500	500	500	500
Maximum Demand (kW)	1.1	1.2	1.3	1.4	1.5
Load Factor	n/a	0.60	0.55	0.50	0.45
Current Structure w/ $16.00 Service Charge					
Customer Charge per Bill	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00
Usage Charge per kWh	0.1336	0.1336	0.1336	0.1336	0.1336
Rates - Demand					
Customer Charge per Bill	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00
Demand Charge per kW	17.94	17.94	17.94	17.94	17.94
Usage Charge per kWh	0.0849	0.0849	0.0849	0.0849	0.0849
Indicative Cost to Serve	$ 76.38	$ 78.20	$ 80.36	$ 82.94	$ 86.10
Current Structure w/ $16.00 Service Charge					
Rate Recovery	82.81	82.81	82.81	82.81	82.81
Subsidy Paid/(Received) - $	6.43	4.61	2.46	(0.13)	(3.28)
Subsidy Paid/(Received) - % of Cost to Serve	8%	6%	3%	0%	-4%
Demand Rates					
Rate Recovery	$ 77.59	$ 79.19	$ 81.08	$ 83.34	$ 86.11
Subsidy Paid/(Received) - $	$ 1.21	$ 0.99	$ 0.72	$ 0.40	$ 0.01
Subsidy Paid/(Received) - % of Cost to Serve	2%	1%	1%	0%	0%

The above is not meant to be inclusive of all demand charge effects. Demand charges will alleviate subsidies between customers with low load factors and with different levels of response to seasonal weather or occupational patterns.

LAC Rate Class Load Factors

General demand rates assessed on maximum demand will, relative to a fixed/variable structure, place more costs on customers with lower-than-average load factors. Based on our review of AMI data, we observed a constant and intuitive trend of load factors increasing with total usage across the Residential, Small Commercial, Small County, and Small School rate classes. The Residential class is the least affected, likely due to the relatively homogenous nature of this rate class. However, in Small Commercial, County and School, there are significant differences in load factors at different levels of usage, likely due to intermittent usage at certain locations. Given this dynamic, we judge it likely that implementation of demand rates may result in significantly increased bills for lower-usage customers in the Small Commercial, County, and School rate classes. Implementing an on-peak demand rate for these classes may help alleviate bill impacts for lower-usage customers, as the intermittent nature of their usage could indicate an ability to shift usage away from the on-peak demand period, limiting the impact of the demand rate.

Table 47 - Load Factor for Representative Low, Median, and High Usage Customers

	Low Use	Median Use	High Use
Residential	0.46	0.48	0.50
Small Commercial	0.03	0.37	0.37
Small County	0.03	0.22	0.27
Small School	0.05	0.21	0.32

Other Advantages and Drawbacks of Demand Rates

Despite the ability of demand rates to better approximate cost causation and utilities' increased ability to measure and bill on demand, system-wide demand rates applied to all customer bills remain rare. Commonly cited reasons for the rarity of demand rates include a lack of customer understanding due to insufficient consumer education and difficulties understanding household demand dynamics, pushback against changes to established rate structures that may benefit certain consumers, and potential for higher average bills.

Residential Reaction to Demand Rates

As previously discussed, demand rates may harm low- and fixed-income households with less efficient appliances and decreased ability to control the timing and extent of demand they place on the system. Customer acceptance of demand charges involves a significant amount of education to help customers understand their demand patterns and how they affect energy bills. Even with education, demand charges may be difficult for residential customers to become comfortable with and understand the charges.

GDS recommends that if demand charges are adopted systemwide that the change be made in conjunction with a significant consumer outreach program, explaining the cost causation principles behind demand charges, approaches that may be taken to reduce household peak demands, and presentations on what residential customers should expect to pay under demand charges on bills before the change is made. Other strategies that may be adopted include alerts to customers at times when their meter shows high demand, charts on bills showing the amount of demand incurred by day, and charts showing the amount of demand incurred by hour on the day of peak demand. These strategies will allow customers to become more familiar with both the concept of demand rates and how their routine will affect their bills.

Demand Rates and Load Reduction Efficiency

While one goal of implementing demand-based rates is recognition of the fixed cost causation, the focus of the utility should remain on incentivizing customers to act in ways that benefit the utility. Traditional demand charges, assessed on maximum demand regardless of when it occurs may reduce individual customer's peak demands, but will be inefficient in reducing overall system peaks. Given LAC's focus on carbon-neutral resources, incentivization of high load factors may not be the correct choice (the goal is for customers to be using clean energy when it is available).

Reductions in peak loads are smaller for traditional demand rates versus those that incorporate a time-variable element as individuals are incentivized to reduce demand at their own peak hours. An individual household does not contribute significantly to the overall load on the system, and an individual's peak hours may not correspond to the system's peaks.

Demand Rate Impacts on Energy Efficiency and Distributed Generation

Little research has been conducted into the effect that demand-based residential rates may have on customer's willingness to invest in energy efficiency or distributed generation due to limited adoption of demand-based rates. However, in a limited number of studies, demand rates have been shown to have deleterious effects on investment in energy efficiency and distributed generation. Study results suggest that shifting recovery of demand-related costs from volumetric rates to demand rates, even if justified under cost-causation principles, results in longer payback periods. Examples of this include the Salt River Project in Arizona, which reports a 95% reduction in rooftop solar permit applications after rates containing mandatory demand charges were implemented. After implementation of demand rates, approximately 14% of existing rooftop solar customers saved money on bills versus a comparable non-generator customer. If the County's goal is to encourage the adoption of DER, demand rate design must be developed in a way that DER adoption is not disincentivized.

Residential Demand Rate Examples

The section below discusses some of the characteristics of the rates we believe may be relevant to LAC. Many of the rates combine elements of both time-of-use and demand rates to reduce peak demands.

Midwest Energy

In November 2022, Midwest Energy, a cooperative serving customers in central and western Kansas, transitioned to a rate structure that included a demand charge, starting January 1, 2023. For the first year, demand charges are set at $0.00, with the intention of allowing customers to better understand their demand dynamics and how the charge will affect bills. From 2024 through 2026, rates will be phased in slowly, with non-ratcheted demand charges on monthly demand values between $1 and $3 in effect from October-May and charges starting at $2 and growing to $6 for demand occurring during peak hours in June-September. Midwest Energy's demand rate explanatory website[17] is an excellent example of customer education and outreach regarding demand rates.

Flathead Electric Cooperative

Flathead Electric Cooperative has residential rates in its Northwest Montana rate district that incorporate a minimal $2.26 demand charge, billed on demand occurring during on-peak hours (M-F 7-10 AM and 5-8 PM). Flathead does not give customers the option to opt out of the rate and the rate has not attracted significant criticism from ratepayers.

Georgia Power "Smart Usage" Rate

In 2019, Geogia Power received permission from the Georgia Public Service Commission ("GA-PSC") to bill all newly constructed residences under a tariff that includes a demand charge based on demand during on-peak periods. Customers were able to opt out of the rate and take service under a standard fixed/variable rate. In Georgia Power's 2022 rate case, witnesses for GA-PSC's Public Advocacy Staff presented analysis that customers on the demand rate paid on average $200 more than a standard residential customer. Other intervenors claimed that customers with low usage were likely to pay more when billed under demand rates and that a significant number of customers were opting out of the program. Georgia Power agreed in settlement to its 2022 rate case to end the default assignment of customers to the program.

13.2 Time-of-Use Rates

Time-of-Use ("TOU") rates are a form of time-variable pricing which seeks to alter customer behavior by sending price signals that discourage consumption during periods with high energy costs and reduce peak demand. Traditional fixed/variable rate designs apply the same charge to a unit of consumption regardless of when it occurs, but the actual cost of that energy that must be paid by the utility has exposure to market forces of supply and demand. Even in cases where a utility has long-term power contracts or generation ownership to hedge against that exposure, load shifting enabled by TOU rates may allow for negotiation of lower cost contracts for power based on consumption patterns.

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[17] demand-rates.mwenergy.com

Benefits of shifting demand have both immediate and long-term benefits to the utility and its customers. Some costs, such as transmission charges between generation and the subject distribution system, are primarily determined by the relative contribution of the distribution system to overall peak demand on the electric grid. Many utility investments, including those in distribution and generation assets, are designed to accommodate a given level of demand, giving an opportunity for properly designed TOU rates to reduce the overall investment a utility must make per connection.

A utility may also seek to achieve objectives less directly related to costs, such as encouraging consumption of renewable energy sources, promotion of energy efficiency or electrification efforts, affordability efforts, or other policy objectives.

There are several common time-variable price structures, which are briefly described in the table below:

Rate Name	Rate Type	Rate Description
Time-of-Use	Static Base	Vary based on fixed schedule to recognize predictable changes in the cost of power. Rates are predetermined.
Critical Peak Pricing	Dynamic Rider	Prices are increased at times of peak demand, reductions in usage at these times create lower bills or produce credits.
Variable Peak Pricing	Dynamic Rider	Higher charges at times of peak demand that have been identified by the utility, commonly on a day-ahead basis. Difference between peak pricing and normal pricing may vary based on utility's desire to reduce demand.
Peak-Time Rebate	Dynamic	Customer is refunded for shifting load out of peak periods.
Real-Time Pricing	Dynamic Base	Cost of energy on customer bills is based on marginal cost to procure energy.

13.2.1 TOU Issues Specific to Los Alamos County

The adoption and effectiveness of time-of-use rates is dependent on whether ratepayers believe that they can achieve savings by lowering their bills. As discussed above, one of the primary goals of TOU rates is taking advantage of periods of lower-cost energy. Due to the current structure of the Resource Pool, Los Alamos ratepayers are exposed to the average cost of energy, diminishing the ability of LAC to capture savings and pass them on to retail customers.

TOU rate designs and savings are highly dependent on the generation mix available to the utility. Changes in generation mix, such as the ability to purchase from new low-cost renewable resources, may change the utilities' approach to TOU rate design. LAC's generation mix at the time TOU rates can be implemented is currently unknown, making it difficult to provide recommendations as to specific rates and strategies to implement to target times of low-cost energy.

13.2.2 Rate Design – Time-Based Rates

13.2.2.1 Cost Components and Allocations

Due to the design of the power pool, shifts in usage may not materially affect the overall cost of power passed through to LAC customers. Reductions in peak demand will occur, which we price at approximately $156.66 per Non-Coincident Peak ("NCP") kW. Historically, the application of TOU rates has created reductions in peak demand ranging from 3% to 10%, depending on the incentives provided to customers. Our illustrative TOU rates incorporate an assumption of a 5% reduction in peak load, leading to approximately $106,000 in savings, which is passed on to customers who reduce on-peak consumption.

13.2.2.2 Rate Structure Options

TOU Peak/Off-Peak Ratio

The peak/off-peak price ratio is a measure of the relative price difference for a unit of consumption at on and off-peak times. The peak/off-peak price ratio is seen as the most critical lever possessed by the utility to incentivize changes in consumption patterns.

Table 48 - Illustrative Peak/Off-Peak Price Ratios

Utility	On-Peak Rate	Off-Peak Rate	On/Off Peak Ratio	Standard Rate per kWh	Standard/Off-Peak Ratio
Jemez	$ 0.158884	$ 0.092463	1.72	$ 0.122720	1.33
PNM TOU	0.158052	0.060888	2.60	0.128664	2.11
Kit Carson	0.163200	0.076110	2.14	0.135110	1.78
LAC Illustrative TOU	0.239713	0.095000	2.52	0.141300	1.49

Peak/Off-Peak Hours Determination

Hours designated as peak or off peak will vary on the utility's exposure to time-dependent electric costs and consumption patterns of customers. In LAC's case, less control can be exerted over the average cost of energy passed through from the Resource Pool, making reductions in peak demand the primary target of TOU rates.

Annual Peak/Off-Peak Designation Option

Under this option, the same peak hours would be used throughout the year. This approach provides a good fit for LAC as peak demands tend to occur at the same time regardless of the season. Peak hours would start at 5 PM and end at 11 PM. Approximately 31% of current residential usage falls within these hours. This approach has the benefit of being more easily remembered and adopted for ratepayers. However, due to the seasonal differences in peak usage it would result in potential load shifting onto hours in which high demand already exists (*e.g.* 4-5 PM in June/July) and causing unnecessary reductions in load in shoulder months where relatively low load conditions exist through 6PM and evening load events are on average shorter duration.

Seasonal Peak/Off-Peak Designation Option

The second option would be tailored to reduce seasonal load characteristics. In summer months (May-September), peak hours would start at 4 PM and end at 11 PM. In winter months (November-March), peak hours could occur in the morning from 8 to 10 AM and afternoons from 6 to 11 PM. No peak rates would be assessed in shoulder months. Under this designation, approximately 30% of current residential usage occurs in on-peak hours. This approach has the benefit of more accurately targeting time of peak demand but adds complexity to the rate design.

Eligible Customer Classes

The primary targets of TOU rates are residential households, which are seen as having more flexibility than other ratepayers to shift the timing of their usage. Discussions with LAC management revealed several other potential classes of customers for which time-of-use rates may be appropriate, depending on the specific generation mix that is achieved at the time rates are put into place. Implementing TOU rates for School and County ratepayers may allow those customers to change operations in ways that will reduce demand peaks and lead to savings for the utility.

TOU Rate Enrollment

There are three main options when it comes to enrolling customers in TOU rates. The rate may be mandatory, opt-in, or opt-out. An opt-in enrollment strategy involves customers self-selecting for TOU rates, while in an opt-out enrollment the TOU rate is applied to bills of all customers other than those requesting to be billed under non-variable rates.

A meta-study by the DOE in 2015 determined that opt-in enrollment resulted in significantly less eligible customer participation (24% average) than opt-out enrollment (93% average). Some pilot programs suggest that utilities employing opt-out enrollment will see less engagement, and lower per capita reductions in peak, while achieving larger aggregate peak load reductions.

13.3 Alternative Rate Structure Recommendation

GDS believes that a time-variable rate design makes more sense for the County than a demand rate, even though the utility is not directly exposed to hourly fluctuations in the cost of power. The main reason for this recommendation is that a demand rate being applied to peak demand at a location regardless of timing may does not incentivize customers to reduce load at times of peak demand. After reviewing system cost components and characteristics, we believe that the potential to lower the overall cost of power to the utility and reduce needs for distribution system upgrades would bring the most benefit to the system.

Instead of seeking to take advantage of lower power costs, we recommend that the rate be designed to reduce demand for the system both at times of local distribution system and Resource Pool peaks. Either a usage or demand-based rate could achieve these goals, but GDS recommends that the rate be usage based as it is easier for customers to understand and is comparable to rates put in place by nearby utilities.

Our illustrative rate design for TOU rates and resulting bill impacts are presented in Appendix D.

13.3.1 Opt-Out Structure

Opt-out rates drive higher levels of participation and reductions in load than opt-in rates and allow customers without interest or that would be financially harmed to avoid penalties. We believe that the opt-out structure provides the best balance of promoting utility goals and providing customer choice.

13.3.2 On/Off-Peak Periods

Given the relatively constant year-round demand peaks that occur between 5 and 11 PM, adopting a consistent on-peak period throughout the year would be the most effective approach to reducing demand. A more targeted approach would result in more usage being designated on-peak but would create friction by causing consumers to have to shift routines to take full advantage of the rates. Given that winter peaks occurring result from heating load, response to morning peak hours may be limited and reduce overall participation.

13.3.3 Mitigate Potential Revenue Losses

Given the limited ability to pass through savings to consumers, we recommend that initial rates be set in a way that usage shifts will not significantly reduce the amount of net revenue collected by the utility. Based on an assumed 3% reduction in load at the time of the Resource Pool peak, LAC would see demand-related savings of approximately $90,000. Our illustrative rate design passes these savings on to customers achieving reductions in usage during peak hours. As the effectiveness of TOU rates for LAC is better understood, rates that better reflect reductions in load achieved can be put in place.

13.3.4 Peak/Off-Peak Ratio between 2:1 and 3:1

If a usage-based time variable rate is TOU, rate peak/off-peak ratios typically fall between 2:1 and 5:1. We recommend ratios that fall between 2:1 and 3:1 to both provide adequate incentives for customers to reduce usage and avoid excessive opt-outs.

13.3.5 Demand Rate Recommendations

In the case that the County determines that it will implement system-wide demand rates without a time-variable element, we recommend that demand rates be phased in as opposed to an immediate recovery of all demand-related costs. This approach should minimize customer confusion and will give all stakeholders time to become comfortable with the effects of demand rates, easing the transition in the rate structure.

For developing rate recommendations, we have assumed that the hourly data currently available from AMI meters will be used for determining billed demand. If LAC gains the capability to measure more precise levels of demand, rates will need to be recalculated using the appropriate denominator for the demand measurement selected. Use of hourly usage measurements in place of demand does bring some benefits, the main one being that spikes in usage over periods shorter than an hour will not be as extreme as demand measured over a shorter interval. This will allow LAC customers some level of protection against unexpected or unavoidable demand charges.

While a ratchet mechanism, which would result in bills being based on a maximum demand over a given period rather than in an individual month, would more fairly apportion demand-related costs, it would reduce LAC's customers' ability to control their electric bills and may unfairly impact some classes of customers with relatively less efficient means for either heating or cooling their homes. Ratchets may also disincentivize customers from reducing load in subsequent peak periods if high demand has occurred. Therefore, GDS recommends the use of unratcheted demand values for residential customers.

13.3.5.1 Recommended Residential Demand Rates

Total demand-classified costs of service for the average residential location total approximately $38.45 per month, or $18.26 per kW. Recovery of this entire amount through demand charges, even in conjunction with reductions in usage charges, could severely impact customer bills, particularly those customers with lower levels of overall usage and less efficient homes.[18] If the County implements demand charges, we recommend relatively small demand charges be put in place, focused on reducing load at peak times. Our demand rate recommendation for residential customers can be found in Appendix E.

13.3.5.2 Small Commercial, County, and School Recommendation

Due to the variety of loads and the inability to change usage patterns, we do not recommend demand rates for these customer classes. If the County does implement demand rates for small customers, we recommend that they be phased in and revenue-neutral, similar to our residential recommendation.

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[18] AMI data shows that lower usage customers have on average slightly lower load factors than customers with high usage.

14 Distributed Energy Resource Rates

The widespread adoption of DER systems, such as rooftop solar, poses both opportunities and challenges to utility distribution systems. The question of the appropriate rates for these customers has been the subject of considerable debate as such systems have proliferated, the main concern being whether the full cost of serving DER customers is being recovered in rates and if traditional cost of service methodologies result in a correct apportionment of costs.

14.1 Cost Recovery Distortions Caused by Distributed Generation

As shown in Figure 29, the current fixed service charges do not recover the fixed costs of service for a residential customer. While this is generally regarded as appropriate for a variety of policy reasons, it means that a portion of costs that are fixed in nature are recovered through volumetric rates. If a customer has an alternative source of electricity, these fixed costs may go unrecovered.

Since DER cannot be relied upon to provide power concurrent when high demand occurs (for instance solar output is reduced in winter evenings when heating load is high or may be placed out of service), DER customers have the same potential maximum demands on the distribution system as a customer without DER. Utilities must design the distribution system with the assumption that it will have to serve the full load of all customers, leading to the fixed investment required to serve a customer being equal, regardless of the presence of DER. The existence of DER may also require improvements to the distribution system and make forecasting future power needs more difficult.

While customers will have various reasons for installing DER, a primary consideration is often whether the system is anticipated to save the customer money on their electric utility bills. Utilities wanting to incentivize or disincentivize DER system installations can use direct and indirect subsidies to modify the payback period.

Mechanisms for decreasing or eliminating the subsidies provided to DER in electric rates have been known since DER systems began being installed; therefore, any existing subsidy should be assumed to be intentional rather than a failure to anticipate potential issues. During review of previous board discussions and presentations made by staff and outside consultants, we identified several instances where the BPU was made aware of subsidies in the rates being charged to DER, with no action being taken to reduce the subsidy. The level of the subsidy being provided must be viewed through the prism of overall utility policy goals, with the knowledge that changes to subsidies change the underlying economics of DER installation and may increase or decrease adoption of DER.

14.2 Common DER Metering and Billing Arrangements

There are three common approaches to metering and billing distributed generation customers: (i) net metering, (ii) net billing, and (iii) buy-all/sell-all.

14.2.1 Net Metering

Net Energy Metering ("net metering") has historically been the most common approach used when billing distributed generation ("DG") customers. Under a net metering arrangement, the customer's bill is based on a single "net" usage value provided by the meter. This can be visualized as the meter's volumetric measurement spinning forwards when power is being taken from the grid and backwards when power is being provided. If there is a net surplus of energy consumed, the customer is billed at the standard rate for their class. If there is a net amount of energy exported to the system, the customer is credited.

14.2.2 Net Billing

In a net billing arrangement, all consumption is billed at one rate (typically that paid by non-DG customers), and all generation is credited at a separate rate. Instead of the single metering point utilized in a net metering arrangement, consumption and excess generation are separately metered or measured separately with a meter that has net billing ability. In a net billing arrangement, the customer maintains the ability to utilize energy from the grid and their own generation as well as sell excess capacity to the utility.

14.2.3 Buy-All/Sell-All

A buy-all/sell-all arrangement requires all generation from DER to be sold to the utility and does not allow for the generation owner to self-consume. The location with the consumption meter is treated the same as any other customer that is on the same rate schedule.

While the design of interconnection between the DER system and the grid and metering limitations may dictate a certain approach to billing, the choice of which of the three to adopt is theoretically divorced from the physical layout of the system. A utility can adopt a net metering approach even if the metering system produces separate gross consumption and generation values. Similarly, the information provided by a separately metered generation source could be used to perform a net billing calculation. For rate design purposes, it is the billing mechanism, and not the physical layout, that is the most important consideration.

Figure 40 - DER Billing Calculations

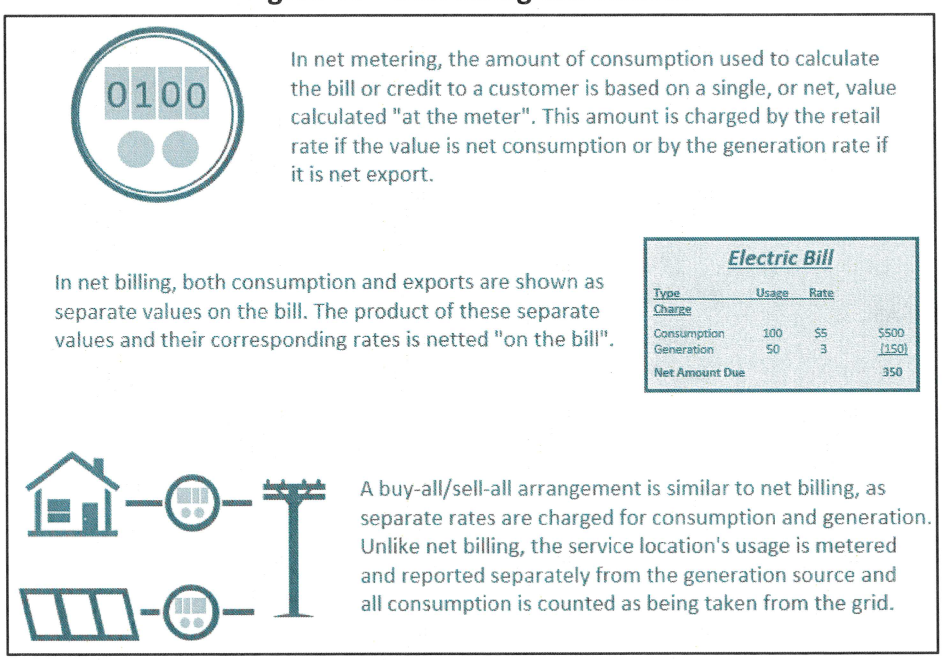


Table 49 - Characteristics of DER Billing and Metering Mechanisms

Billing mechanism	Netting calculation performed	Can customer use DER to reduce usage from grid?	Does generation need to be seperately metered?	Inherent Subsidy
Net Metering	At Meter	Yes	No	High
Net Billing	On Bill	Yes	No	Varies
Buy-All/Sell-All	None	No	Yes	Low

Table 50 - Advantages and Disadvantages of DER Billing Mechanisms

Billing mechanism	Advantages	Disadvantages
Net Metering	Calculation based on one net value, easy to understand Only one meter required Large inherent subsidy crates economic incentive for DER	Due to netting calculation at meter, utility effectively "pays" retail rate for generation until exports exceed imports, which creates subsidies Ability to self-generate leads to undercollection of demand and customer costs intended to be recovered in volumetric rate
Net Billing	While customer is allowed to self-generate, separate pricing of consumption and generation eliminates subsidy inherent in net metering approach	Subsidy created by self-generation still exists
Buy-All/Sell-All	Elimination of self-generation means that load source does not receive subsidy beyond that provided to other customers in class Decoupling of retail rates and payments for generation simplify determination of whether costs associated with DER are recovered	Requires two meters Elimination of subsidy may disincentivize adoption of DER

14.3 Current LAC DER Rates and Rate History

Los Alamos currently utilizes a net metering billing arrangement. Under rule E-5.05, net power supplied to the customer is billed at the customers' applicable standard rate. When exports to the grid exceed the amount taken, the rule allows for recognition of the excess generation to be credited to the customer at the average capacity and energy cost from the Resource Pool for the previous year, with an annual true-up mechanism to reflect actual power costs over the period. The net metering rate structure has generated considerable attention from LAC staff, the BPU, and citizens of the County since its introduction.

14.3.1 2014 Leidos Rate Study Recommendation

The 2014 Rate Study recommended the implementation of an additional $12.00 per bill charge (referred to as a "Net Metering Charge") to recover fixed costs that were not being recovered from DER customers. No direct calculation of the $12 charge is presented in the report or COSS schedules. The BPU determined that further evaluation of the reasonableness of the Net Metering Charge was needed before it was approved, given the level of concerns expressed by citizens and board members, and did not implement the charge.

14.3.2 2015 Future Energy Resources Committee

In 2015, the County formed the Future Energy Resources Committee ("FER Committee"), a citizens committee made up of seven members selected by the BPU, to develop recommendations on future generation resources, to achieve carbon neutrality, and to recommend policy treatments for distributed generation customers, while taking into consideration the concerns raised by citizens to the 2014 Rate Study Recommendations. The resulting recommendations for DER included:

- Clearly communicating to customers that rates and rate structures for DER customers were not guaranteed at any point in the future.
- Adoption of a DER rate structure that achieves full cost recovery.
- Payments for generation based on average avoided costs.
- Implementation of a Value-of-Solar tariff to be phased out as other renewable resources became available.

All recommendations of the FER Committee were adopted by the BPU as part of its Strategic Policy during the March 16, 2016, Regular Meeting.

14.3.3 2016 Value of Solar Study

In November 2016, the results of a "value of solar" study performed by Utility Financial Solutions, LLC was presented to the BPU. This study included the assumptions that any distributed solar generation would offset the need to construct a natural gas-fired turbine generating unit at an all-in cost of $1,274 per kW and that the average solar installation would reduce peak demand by 7%. The study only quantified the economic value of solar, ignoring indirect non-economic factors such as policy goals, environmental, and societal impacts.

The avoided cost of additional generation and savings that would occur at the transmission and distribution levels was calculated at an average annual solar avoided cost of $0.08388 per kWh for residential solar and $0.09427 for commercial solar, assuming a "buy-all, sell-all" approach was taken. If the net metering approach was continued, the 2016 Study concluded, additional monthly fixed charges of $4.56 per month per KW of installed capacity for residential and $2.45 per month per kW of installed capacity for commercial customers would be necessary to avoid subsidization of other customer classes. Based on average levels of residential installed capacity at the time, this additional charge would be approximately $22 per month. The charge was to be put in place only if the net metering approach was continued *and* the higher credit reflecting value of solar was put in place. However, the County did not change its approach to billing DER.

14.3.4 2018 Staff Report on Alternative Rate Structures

In its April 2018 meeting, LAC Staff presented potential rate structure alternatives for customers with DG to address a concern that under the net metering arrangement for DG customers, customers were able to completely offset their bill by selling to the grid, avoiding paying their fair share of fixed costs. Staff noted that:

- LAC places both generation and net meters at location meters and was capable of separately reading generation, gross consumption, and gross export. However, the generation meters were not being read and changes would be needed to the billing system to do anything other than net billing. Both the then-current billing system and the Tyler Muni System, then being tested for implementation, were found to be able to accommodate a rate structure with an individual generation rate.
- Customers with DER were generating significantly more energy than required, with an example given of a customer that produced approximately 25% more annual energy than needed for the location. Notably, the largest amounts of generation were occurring in summer months while the customer used substantially more energy in winter months.

LAC Staff recommended the implementation of a rate that included a minimum system fixed charge that would capture any costs being avoided by distributed generation customers. BPU members noted one of the considerations of a DG owner would be the payback period that it would provide. BPU members also noted that PV installations may accelerate other carbon goals such as adoption of EVs, and that consideration of the Board's carbon-neutral policies was necessary when rates that were designed as subsidies provided to PV would incentivize installations. Issues related to whether subsidization was beneficial to the utility or whether installation of rooftop solar was a reasonable alternative to utility-scale installations were highlighted for further discussion. The BPU indicated that the issue of DG rates was something that needed to be addressed and requested further analysis from Staff on buy-all/sell-all and value of solar rates.

14.3.5 Current LAC Policy Regarding DER

LAC has seen a widespread adoption of DER and promotes its installation for system resiliency and as a way to meet renewable energy goals. Adoption of rates that reduce or eliminate the subsidy provided to DER can be reasonably anticipated to reduce demand for DER. The level of subsidy that should or should not be provided to an individual customer with DER, and the nature of that subsidy, is outside of the scope of this report and our recommendations should be considered in context with the overall means in which the utility intends to achieve its goals.

Under the current rate structure, DER owners will see a bill reduction due to self-generation and receive a credit for a portion of generation which exceeds the cost that LAC would pay from another source. A customer that makes an investment in energy efficiency (such as an upgraded HVAC system or new windows) sees only the reduction in their bill. In the absence of policy goals or an analysis that the relative benefits of DER to the utility exceed those of other means of reducing consumption, LAC may be incentivizing customers to install DER systems rather than making investments in energy efficiency, which may provide similar benefits.[19]

14.3.5.1 DER Subsides and Effect on Sales and Revenue

Concerns about subsidization are mitigated by the following DG rate design decisions made by LAC:

1. Distributed generation capacity is limited to that needed to provide for average needs of a location.
2. The application of a lower, cost-based energy rate to any net generation sold to the grid limits the subsidization that occurs under a basic net metering program to the proportion of demand and customer-related costs that would otherwise be collected through volumetric charges.
3. Costs of incremental improvements to transformers and direct costs of DG interconnection are intended to be recovered in the initial charge that must be paid by commercial customers when DG systems are connected to the grid.[20]

Despite these restrictions on the ability of DER to gain subsidization from other users, concerns still exist over the potential subsidization of these customers. The following sections will quantify the amount of the subsidy being given to DER owners.

Determination of Subsidization Provided to DER Under Residential Rates

Around 240 Residential customers had DER installed as of June 2022, or approximately 3% of the total residential population. On average, customers who have installed DER have higher than average annual usage before installation of DER, with an average close to 750 kWh per month, 30% over the systemwide average for residential customers. After installation of DER, the levels of energy provided by the utility dropped to slightly below average at 532 kWh per month. Customers with DER tend to see significantly lower consumption from the grid than non-DER customers during summer months. However, this is offset by higher-than-average consumption from the grid in winter months. The largest reductions in usage resulting from installation of DG occur in May through August, during which time usage requirements from the utility are reduced by approximately 36%.

[19] For example, improving insulation will decrease total usage both in winter and summer regardless of time of day, while a rooftop solar installation cannot produce power overnight and may be less efficient in winter.

[20] While this recovery is anticipated within the current application for DER interconnection, it is unclear if any costs have been regularly recovered.

Figure 41 - Residential DER Average Monthly Consumption per Connection – 2022

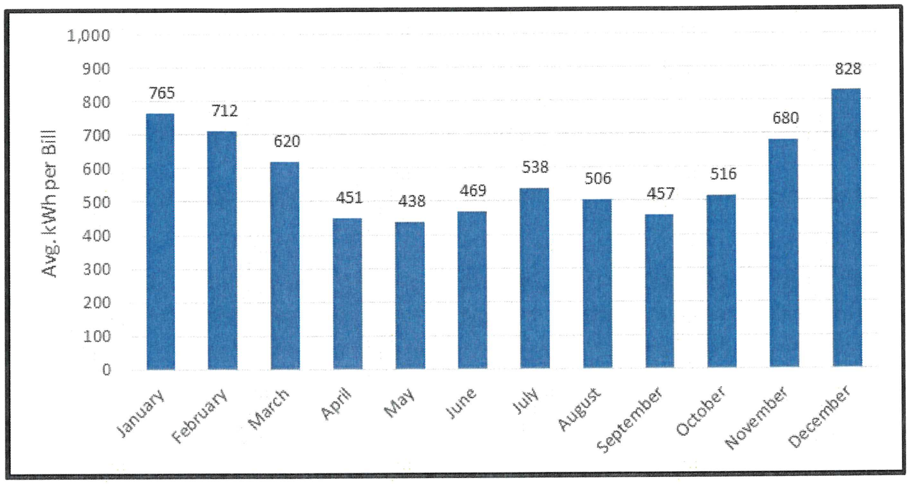
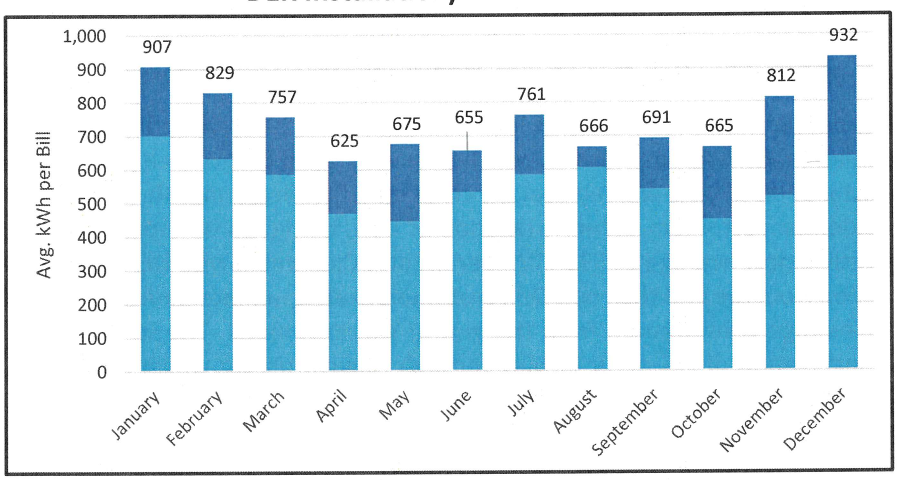


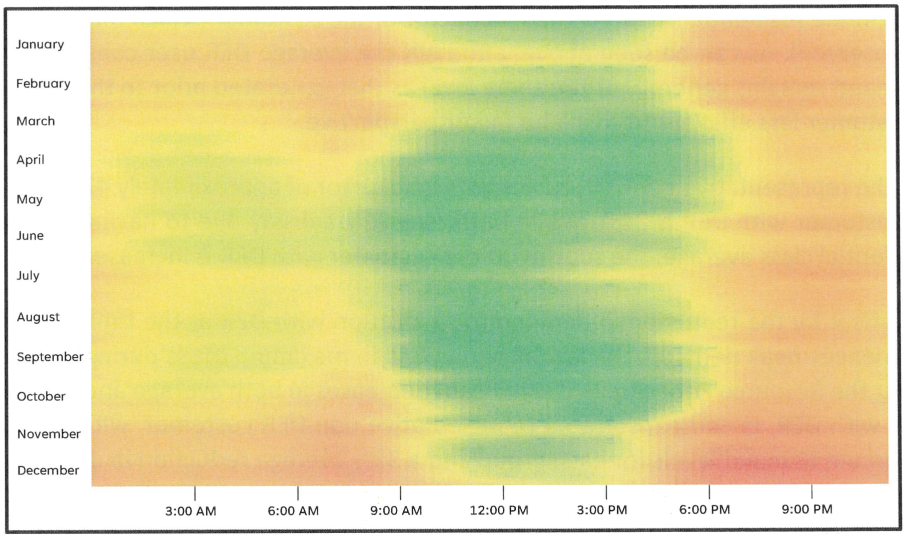
Figure 42 - Residential DER Average Monthly Consumption per Connection (Before and After DER Installation) – 2019-2022[21]



DER Customers not only have very different total usage from the typical residential customer, but usage throughout the day differs. As may be expected given that most or all DER is photovoltaic, the demand from DG customers is limited during daylight hours as compared to night, with peak loads occurring in the evening of winter months.

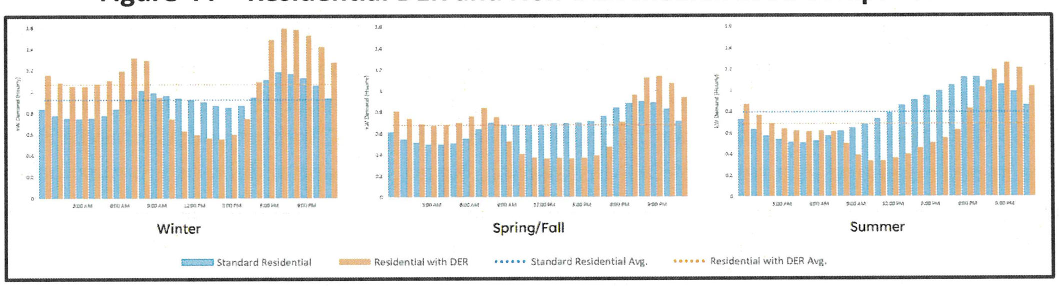
[21] Consumption subsequent to DER installation shown in light blue for comparison.

Figure 43 - Residential DER Load Map (Utility-Provided Electricity)



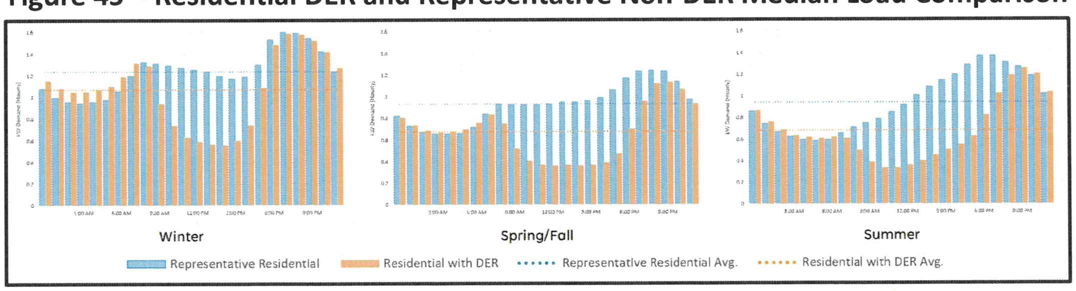
While the timing of load presented indicates different consumption patterns in comparison to the standard residential customer (Figures 2 and 3 in Section 3), it only provides an indication of load relative to peak demands placed by DER customers and does not present relative levels of load. That the average DER customer still consumes about the same level of energy from the grid than the average residential customer indicates that a customer with DER has high usage during hours that DER is not available. This is borne out by the hourly load information provided by AMI, as presented below:

Figure 44 - Residential DER and Non-DER Median Load Comparison



As customers with DER tended to have higher consumption levels than the average residential user, residential users were filtered and adjusted to create a more representative sample for better comparison of consumption patterns before and after installation of DER:

Figure 45 - Residential DER and Representative Non-DER Median Load Comparison



The results of the COSS suggest that under the current rate structure, the main factor that leads to intra-class subsidies in the residential class[22] is the load factor of the customer (which may vary dependent on time period observed). As can be seen above, although the average DER user consumption is reduced, maximum demand remains generally at the same level as that generated prior to the installation of DER, making the customer less efficient from a load factor perspective.

Compared to the representative non-DER customer's load factor of approximately 42%, the load factor of the average customer with DER is 34%. While both receive a subsidy due to having a lower load factor than the Residential class average, the subsidy to the customer with DER is increased.

This effect is offset by the reduction in demand for a location with DER at the times the Resource Pool typically experiences peak demand. Review of reductions in maximum loads during likely summer peak event hours for the Resource Pool revealed significant decreases in both average and maximum demands for customers with DER, in comparison to a representative non-DER customer, with a 27% reduction in recorded maximum demand levels for each group and a 39% average reduction in demand over times at which peak usage may occur. No demand reduction was observed during times of potential winter Resource Pool peaking events.

To calculate the benefit associated with this reduction in load, the allocation of costs between the Resource Pool participants was adjusted. As demand-designated costs in the resource pool are generally fixed and a reduction in demand may not result in significant savings to the pool, it was assumed that the total cost to the resource pool remained the same. The result of this calculation was that 1 kW of load reduction at peak would result in $33.06 of annual savings to LAC. The average reduction of 0.5 kW at the time of the Resource Pool peak resulting from installation of DER is directly attributable to that customer and should be included in the calculation of any subsidy being paid or received.

The value of solar is outside the scope of the current study, however the results of the 2016 Value of Solar study can be used to estimate the benefits of solar at the distribution level. That study identified $0.00113 per kWh in avoided costs at the distribution level because of reductions in demand caused by DER generation. The study did not have access to hourly AMI data from LAC meters and assumed a 7% average decrease in peak demand as a result of DER installation. As no substantial decrease in maximum annual demand is observed between an average customer with DER and a comparable customer without DER, we eliminate this value from the calculation.

A calculation of the subsidization of a representative non-DER and average DER customer is provided below.

[22] Ignoring for now any subsidy occurring because of the net metering arrangement.

Table 51 - Illustrative Subsidy Provided to DER under Current Rates

	Usage (kWh)		Bill - Current Rates		DER Bill Savings		Cost to Serve		Subsidy Paid/(Received)	
	DER	Non-DER	DER	Non-DER	$	%	DER	Non-DER	DER	Non-DER
January	765	907	$ 110.07	$ 128.29	$ 18.22	14.2%	$ 114.66	$ 129.67	$ (4.58)	$ (1.38)
February	712	829	103.30	118.25	14.96	12.6%	112.18	126.01	(8.89)	(7.76)
March	620	757	91.54	109.02	17.48	16.0%	107.89	122.64	(16.36)	(13.62)
April	451	625	69.78	92.17	22.39	24.3%	99.96	116.50	(30.18)	(24.33)
May	438	675	68.10	98.52	30.42	30.9%	99.35	118.81	(31.25)	(20.30)
June	469	655	72.17	95.96	23.79	24.8%	100.83	117.88	(28.66)	(21.92)
July	538	761	80.96	109.52	28.56	26.1%	104.04	122.83	(23.08)	(13.30)
August	506	666	76.81	97.35	20.54	21.1%	102.52	118.39	(25.71)	(21.04)
September	457	691	70.59	100.61	30.02	29.8%	100.25	119.57	(29.67)	(18.97)
October	516	665	78.14	97.27	19.13	19.7%	103.01	118.36	(24.87)	(21.09)
November	680	812	99.12	116.12	17.00	14.6%	110.66	125.23	(11.54)	(9.11)
December	828	932	118.16	131.47	13.30	10.1%	117.61	130.83	0.56	0.64
Total	**6,979**	**8,975**	**$ 1,038.73**	**$ 1,294.55**	**$ 255.82**	**19.8%**	**$ 1,272.96**	**$ 1,466.73**	**$ (234.23)**	**$ (172.18)**
Marginal Subsidy Created by DER									**$ (62.05)**	
Savings from Resource Pool									**15.21**	
Savings at Distribution System Level									**-**	
Net Subsidy (Increase)/Decrease Due to DER									**$ (46.84)**	

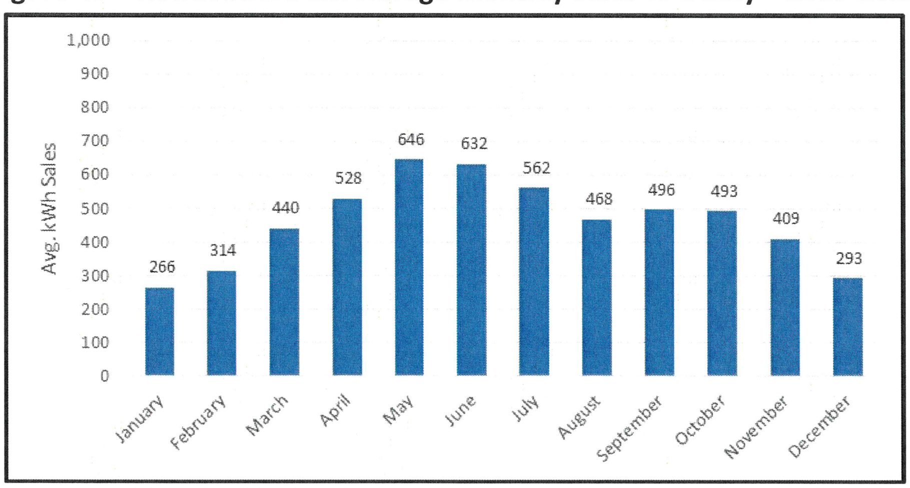
Based on the results of calculating subsidies for average customers in each class, the total subsidy provided because of DER installation is $3.90 per month, or $46.84 per year. Every customer's characteristic and resulting subsidy will differ, but even assuming a population of 250 DER systems, based on the average presented above, total cost of the subsidy annually is less than $12,000 or about $1.18 per LAC customer annually if the cost is spread evenly over the system.

Subsidy Provided by Net Metering Arrangement

The subsidy presented above ignores any effect the net metering arrangement may have in increasing the subsidy provided to DER customers. If sales to the grid are less than those delivered, the customer is provided a credit equal to the full retail rate per kWh. Any generation provided more than that taken from the grid is credited at the average cost of electricity (both electric and demand costs) to the Resource Pool.

The average residential DG customer over the 2018-2022 period sold an average of 465 kWh per month back to the grid, with most sales occurring in summer months.

Figure 46 - Residential DER Average Monthly Sales to Utility – 2019-2022



Comparing these figures to average consumption levels for DER customers and analyzing the total kWh credits produced at retail and wholesale (Resource Pool) costs results in a total of approximately $330 in annual credits to an average customer with DER.

Table 52 - Calculation of DER Cost Recovery Distortion Under Net Metering Arrangement

	kWh Consumed	Total kWh Sold to Utility	Retail Credit Sales kWh	Avoided Fixed Cost Recovery @ $0.0584 per kWh	Wholesale Credit Sales kWh	Unrealized Demand-Associated Savings @ $0.0398 per kWh	Total Generation Credit
January	765	266	266	$ 15.53	-	$ -	$ 15.53
February	712	314	314	18.34	-	-	18.34
March	620	440	440	25.69	-	-	25.69
April	451	528	451	26.33	77	3.06	29.40
May	438	646	438	25.58	208	8.28	33.85
June	469	632	469	27.39	163	6.49	33.87
July	538	562	538	31.41	24	0.95	32.37
August	506	468	468	27.33	-	-	27.33
September	457	496	457	26.69	39	1.55	28.24
October	516	493	493	28.79	-	-	28.79
November	680	409	409	23.88	-	-	23.88
December	828	293	293	17.11	-	-	17.11
Total	6,979	5,547	5,036	$ 294.06	511	$ 20.33	$ 314.40

14.4 DER Recommendations

GDS concurs with the findings of previous studies that customers with DER are receiving subsidies from other users of the system, at least relative to other members of their rate class with similar consumption characteristics. These cost recovery distortions are inherent in the current net metering arrangement.

14.4.1 Establish Clear Policy on DER Credit Calculation

If credits paid for DER generation are to be calculated using anything other than the direct economic benefits (avoided cost) resulting from that generation, a clear policy should be laid out defining in quantitative or qualitative terms the benefits that are being considered and how each benefit influences the credit rate. Potential benefits that could be considered include environmental considerations, expected future benefits of local generation relating to battery storage, widespread public support of DER installation, grid security, and effects on the local economy. We recommend that if these considerations are judged to influence the credit rate that they be revisited regularly to ensure alignment with LAC strategic policy.

14.4.2 Consistent Treatment of DER Customers

It is apparent that if allowed to self-generate, the existence of DER reduces utility sales and will lead to subsidization. It is not apparent why this usage-related subsidization should be treated any differently than the subsidization occurring at a house that is vacant half the year, declines in usage resulting from investments in energy efficiency, or between high and low usage load factors without DER. Instead of treating DER customers as either members of their own unique rate class or as members of the class they would occupy in the absence of a DER, they are a chimera that poorly captures both the cost of service and the benefits brought to the utility.

The subsidy being created by the application of residential rates to customers with DER is relatively minor and in line with subsidies that are likely being provided to other residential customers. We recommend that customers with DER be treated as members of the applicable rate class first and foremost, with the existence of DER considered a separate and independent trait. This will put DER on even footing with other forms of usage reduction.

14.4.3 Move to a Net Billing Arrangement

The fundamental problem with LAC's current approach to billing and crediting customers with DER is the net metering arrangement. Under this arrangement, it is difficult to accurately capture the cost of service. Application of fixed charges to partially eliminate subsidies is possible, but further complicates discussions over potential subsidizations, is administratively burdensome, and will cause uneven effects on owners of DER. We are of the opinion that the net metering arrangement is fundamentally unsound and should be eliminated.

A buy-all/sell-all arrangement would alleviate concerns over any subsidy being provided to DER by placing them on even footing with other customers within their class. LAC already installs generation meters and should have the ability to read and credit generation separately. Independent measurement will allow for accurate pricing of DER generation as a standalone credit. However, it would represent a fundamental shift in LAC's approach to DER in that it would not allow for customers to self-generate and reduce the level of consumption charges from the utility and may have a material impact on the number of new DER installations.

Given Los Alamos' historical promotion of DER to decrease utility bills, the BPU's goals regarding local solar production, and the potential future benefits of pairing DER with battery storage, we recommend that the utility adopt a net billing arrangement for locations with DER generation as it provides the best balance of stakeholder interests.

14.4.4 Implement Time-Variable Credits for Generation

Crediting all DER generation within a month at the same rate is currently LAC's only option given the limitations of the billing system. When billing software capable of more granular assignment of generation is available, LAC should consider a time-variable rate for DER generation. A time-variable rate will allow the utility to more accurately credit generation for the benefits it provides to the utility, which differ depending on when the generation is available. Future access to or investment in utility-scale renewable energy resources or battery storage may significantly change the value of benefits provided by DER, and time-variable credits would allow for better recognition of these changes as well as incentivizing DER owners to increase energy exports (by reducing consumption) at times with high energy costs.

15 Other Recommendations

15.1 Power Pass Through Rider/Surcharge

Approximately 45% to 50% of the cost incurred by the utility are related to the generation, procurement, and transmission of power. These costs are subject to significant variability and historically higher inflationary pressures than costs arising from the operation of the distribution system.

While LAC has entered into agreements which limit its exposure to fluctuations in the cost of power, market purchases are required if sufficient contracted power is unavailable. LAC does not have significant control over the timing of these purchases, which may coincide with times of high demand and corresponding high costs. While LAC has generally avoided the effects of these events, power markets have shown themselves to be subject to extended periods of high demand and low supply, resulting in severe financial damage for those relying on market purchases.

As with other rate recommendations, we have tried to approach this issue from a holistic perspective, with consideration of LAC's current practices managing and monitoring costs and the approach that has been taken to required rate increases. We believe that a mechanism that automatically adjusts to recover the cost of power is out of step with these practices, but that the County would ultimately benefit from a mechanism that allows it to adjust rates outside of a context of a change to base rates given the ongoing uncertainty of the cost of power.

To maintain governance control over approval of costs, GDS recommends that if a power pass-through mechanism is put in place, that any adjustment be at the request of LAC management with approval by the BPU. The initial surcharge would be set at $0.0000 per kWh, with all expected power costs being collected in base rates, just as has occurred historically. In the absence of realized and sustained power cost increases, there would be no effect on customer bills. If LAC management determined that power costs had varied to the extent that an adjustment was appropriate, evidence of the need for the increase could be provided to the BPU and voted upon. This approach would avoid a direct pass-through of power cost to ratepayers while maintaining the ability to mitigate the impact of power cost increases on the financial condition of the distribution utility and enable more accurate forecasts of future utility cost increases.

16 Addendum – Debt Service Coverage Ratio

This addendum to the original report discusses the impact of changing from a 1.60 to a 1.30 debt service coverage ratio ("DSCR") and how it will affect the County's ability to rebuild depleted reserve funds.

The debt service coverage ratio is a measure of cash in excess of that needed to pay the operating and debt-related costs of running the utility. The utility may be required by bonding covenants to maintain a debt service coverage reserve amount, attain a specific DSCR, or both. Rating agencies evaluate DSCR as one of the factors considered when assessing the financial health of a utility.

The general approach to DSCR involves using revenues less operating expense as the numerator and total debt expense (principal and interest) as the denominator. A result of 1.0 would indicate that the utility is producing the level of cash that is needed to cover principal and interest expenses. A DSCR above 1.0 indicates that there is cash available above what is needed to pay principal and interest expenses. For instance, a utility achieving a 1.30 DSCR is producing 30% more cash than would be needed to pay debt-related items. Similarly, a DSCR below 1.0 would indicate that the utility is not producing enough cash to cover debt-related items. Essentially, the DSCR is a measurement of a utility's ability to absorb increases in operating expenses before its ability to make debt payments from non-reserve sources is impaired. When a DSCR of over 1.0 is being achieved, revenues in excess of cash expenses can be used for other purposes such as building reserves, offsetting the need to issue additional debt for capital projects, or reducing the cost of existing debt.

Methodological differences exist from utility to utility when calculating DSCR. GDS typically uses the "Adjusted Debt Service Coverage Ratio" method as described in the Moody's Investors Service's Rating Methodology – US Public Power Electric Utilities with Generation Ownership Exposure Methodology publication when determining DSCR. In this calculation, the numerator is determined using recurring revenues (inclusive of interest expense but excluding one-time items) less cash expenses and general fund transfers. The denominator is the aggregate debt service amount. Moody's includes general fund transfers in its calculation as "in practical terms, the transfer is a requirement that in many cases is made on a monthly basis."

The most typical target used by utilities when determining DSCR is achievement of the highest ratio that is set out in existing bond covenants. In our experience, a typical range of DSCR targets is 1.15-1.30, depending on the size of the utility, amount of debt carried by the utility, existence of pass-through mechanisms for commodity costs, reserve balances, and other financial indicators. If not based on requirements of bond covenants, DSCR targets may be set considering the level of debt funding required by the utility, the need to produce additional funds, or the impact achieving a higher DSCR has on utility rates.

LAC's DSCR calculation used internally is calculated for the Electric Fund as a whole. The numerator of the calculation is calculated as the sum of utility sales and service, rentals, and miscellaneous revenues less employee salaries and benefits, contractual services, materials and supplies, special closure costs, and other expenses. The denominator is total principal and interest expense.

The amount of excess cash produced by the DSCR is dependent on the overall level of principal and interest expense being paid by the utility. The amount of excess cash produced by a 1.30 and 1.60 DSCR is shown below, both for GDS' and LAC's internal forecasts of debt[23].

Table 53 - Addendum Table 1 – Requirements to Meet DSCR Levels

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
GDS Forecast Debt Service	**$ 1,096,420**	**$ 1,379,194**	**$ 2,283,994**	**$ 2,626,216**	**$ 2,919,804**	**$ 3,307,400**	**$ 3,307,400**	**$ 3,307,400**	**$ 3,307,400**	**$ 3,307,400**
Available Cash Produced by:										
1.60 DSCR	657,852	827,517	1,370,397	1,575,730	1,751,882	1,984,440	1,984,440	1,984,440	1,984,440	1,984,440
1.50 DSCR	548,210	689,597	1,141,997	1,313,108	1,459,902	1,653,700	1,653,700	1,653,700	1,653,700	1,653,700
1.40 DSCR	438,568	551,678	913,598	1,050,486	1,167,921	1,322,960	1,322,960	1,322,960	1,322,960	1,322,960
1.30 DSCR	328,926	413,758	685,198	787,865	875,941	992,220	992,220	992,220	992,220	992,220
1.20 DSCR	219,284	275,839	456,799	525,243	583,961	661,480	661,480	661,480	661,480	661,480
LAC Forecast Debt Service	**$ 1,015,816**	**$ 1,178,311**	**$ 1,161,970**	**$ 1,802,847**	**$ 1,996,129**	**$ 2,146,310**	**$ 1,857,931**	**$ 2,016,601**	**$ 2,374,630**	**$ 2,371,915**
Available Cash Produced by:										
1.60 DSCR	609,490	706,987	697,182	1,081,708	1,197,677	1,287,786	1,114,759	1,209,961	1,424,778	1,423,149
1.50 DSCR	507,908	589,156	580,985	901,424	998,065	1,073,155	928,966	1,008,301	1,187,315	1,185,958
1.40 DSCR	406,326	471,324	464,788	721,139	798,452	858,524	743,172	806,640	949,852	948,766
1.30 DSCR	304,745	353,493	348,591	540,854	598,839	643,893	557,379	604,980	712,389	711,575
1.20 DSCR	203,163	235,662	232,394	360,569	399,226	429,262	371,586	403,320	474,926	474,383

The cumulative balances produced at 1.60 and 1.30 DSC levels, both with and without interest revenues, are shown below. Interest revenue is computed using a 5% return on the average balance of the reserves.

Table 54 - Addendum Table 2 – Cumulative Balance Achieved – Excluding Interest

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Cumulative Cash Collected - GDS Forecast										
1.60 DSCR	$ 657,852	$ 1,485,369	$ 2,855,765	$ 4,431,495	$ 6,183,377	$ 8,167,817	$10,152,258	$12,136,698	$14,121,138	$16,105,579
1.30 DSCR	328,926	742,684	1,427,883	2,215,748	3,091,689	4,083,909	5,076,129	6,068,349	7,060,569	8,052,789
Cumulative Cash Collected - LAC FY25 Forecast										
1.60 DSCR	$ 609,490	$ 1,316,476	$ 2,013,658	$ 3,095,366	$ 4,293,044	$ 5,580,830	$ 6,695,588	$ 7,905,549	$ 9,330,327	$10,753,476
1.30 DSCR	304,745	658,238	1,006,829	1,547,683	2,146,522	2,790,415	3,347,794	3,952,775	4,665,164	5,376,738

Table 55 - Addendum Table 3 – Cumulative Balance Achieved – Including Interest

	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Balance with Interest - GDS Forecast										
1.60 DSCR	$ 2,228,474	$ 3,188,102	$ 4,752,164	$ 6,604,895	$ 8,730,819	$11,201,411	$13,795,533	$16,519,361	$19,379,380	$22,382,401
1.30 DSCR	1,883,102	2,370,868	3,130,075	3,991,948	4,941,898	6,008,126	7,074,355	8,140,583	9,206,812	10,273,040
Balance with Interest - LAC FY25 Forecast										
1.60 DSCR	$ 2,178,903	$ 3,012,509	$ 3,877,746	$ 5,180,384	$ 6,667,023	$ 8,320,354	$ 9,879,000	$11,613,159	$13,654,215	$15,795,653
1.30 DSCR	1,866,539	2,322,197	2,795,612	3,489,768	4,278,066	5,151,960	5,980,872	6,900,020	7,975,220	9,103,345

These balances are compared to GDS' calculated level of completely funded reserves in the charts presented below. Note that the reserve balances differ due to differences in debt service, O&M, and commodity costs existing between the two forecasts. Reserve balances at 1.60 and 1.30 DSCR levels include the interest revenue discussed above.

[23] GDS' forecasted debt service is based on anticipated CIP as of the FY24 budget, and assumes that debt funding will be utilized in order to prioritize rebuilding of reserve balances. GDS has produced a 5-year forecast and assumes the same level of debt funding from FY30 on. LAC's forecasted debt service is based on FY25 budget information and assumes a different level of capital investment as well as some funding of CIP through cash produced by rates and grants, leading to lower overall costs of debt.

Table 56 - Addendum Figure 1 – Target Reserves and Balances Achieved – GDS Forecast

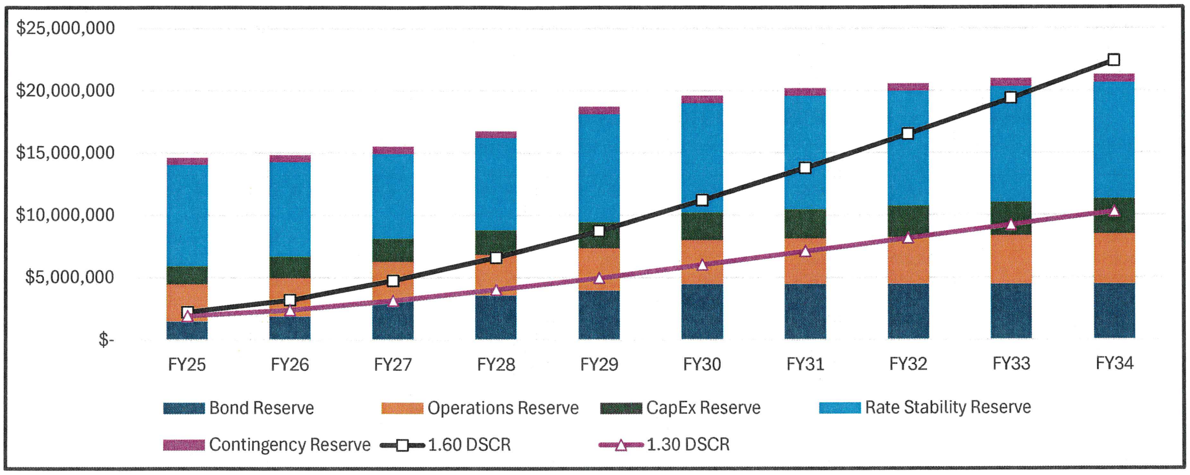
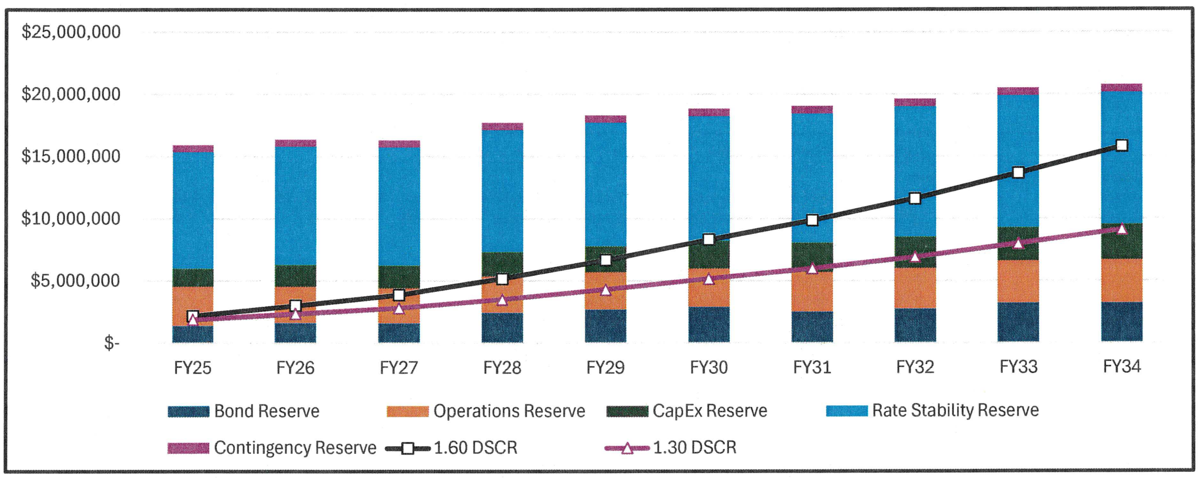
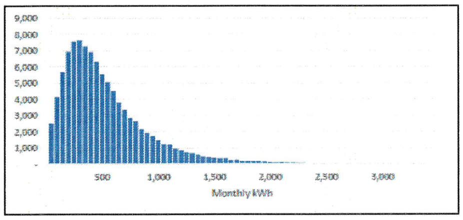


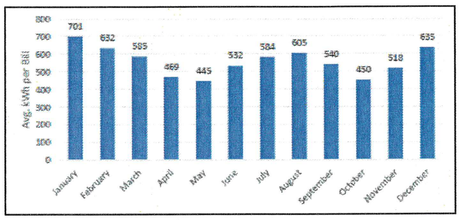
Table 57 - Addendum Figure 2 – Target Reserves and Balances Achieved – FY25 LAC Forecast



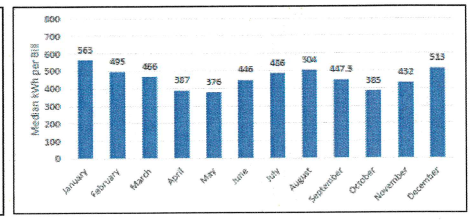
17 Appendix A – Rate Class Usage Information



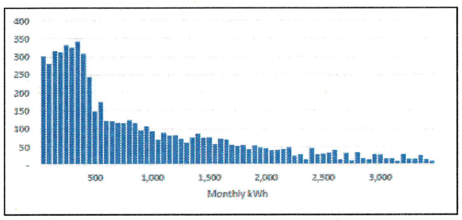
Residential Bill Distribution



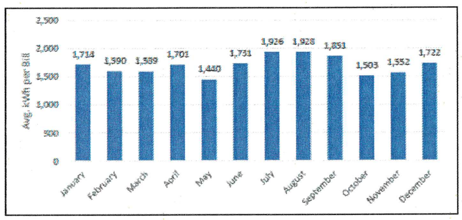
Residential Avg. Usage by Month



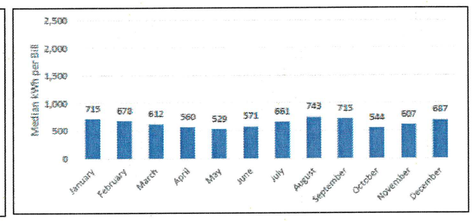
Residential Median Usage by Month



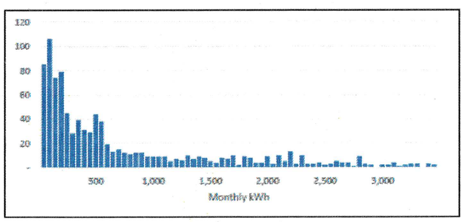
Small Commercial Bill Distribution



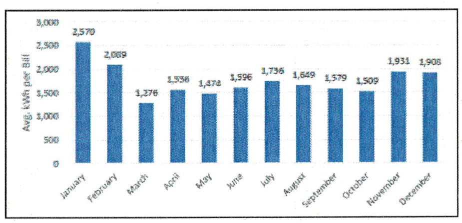
Small Commercial Avg. Usage by Month



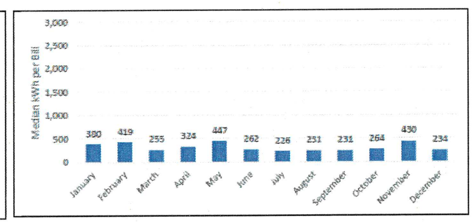
Small Commercial Median Usage by Month



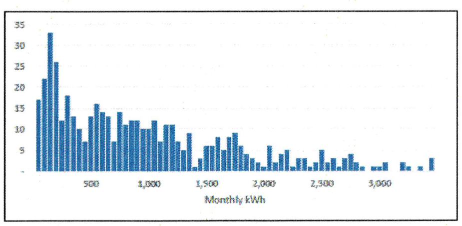
Small County Bill Distribution



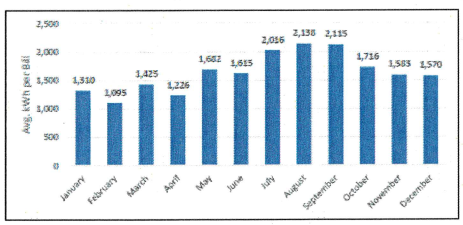
Small County Avg. Usage by Month



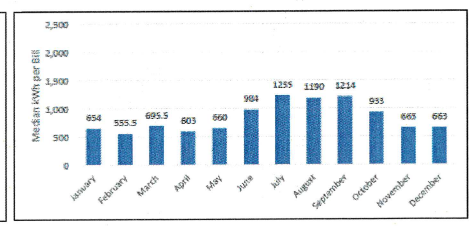
Small County Median Usage by Month



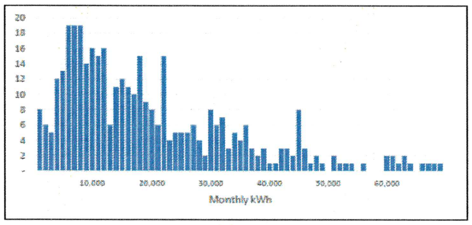
Small School Bill Distribution



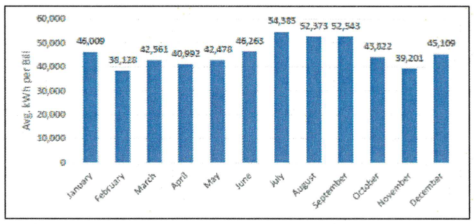
Small School Avg. Usage by Month



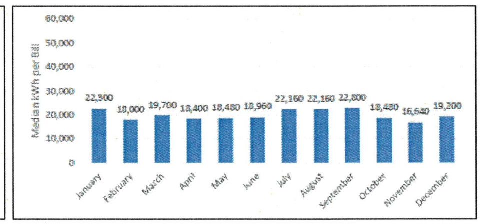
Small School Median Usage by Month



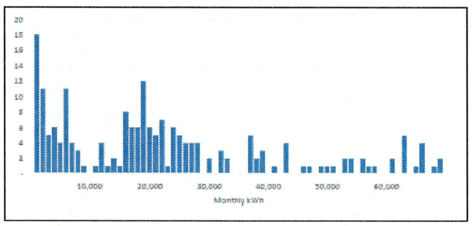
Large Commercial Bill Distribution



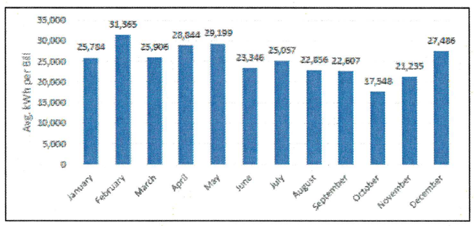
Large Commercial Avg. Usage by Month



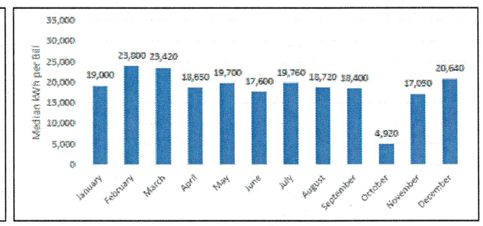
Large Commercial Median Usage by Month



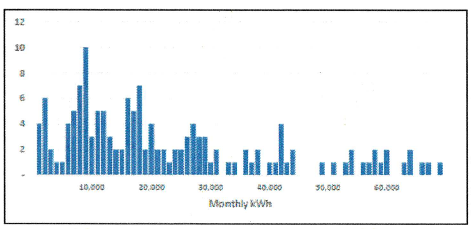
Large County Bill Distribution



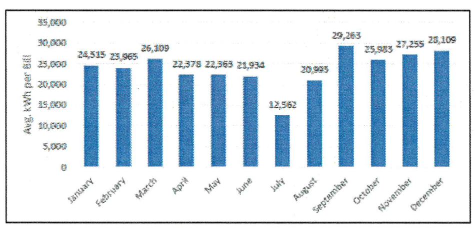
Large County Avg. Usage by Month



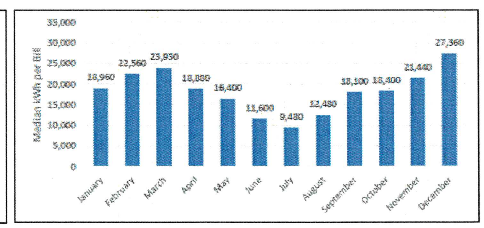
Large County Median Usage by Month



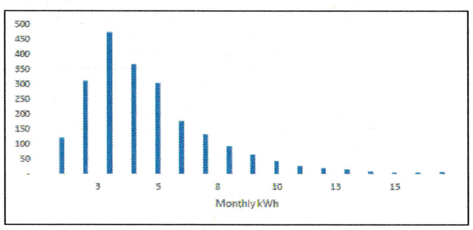
Large School Bill Distribution



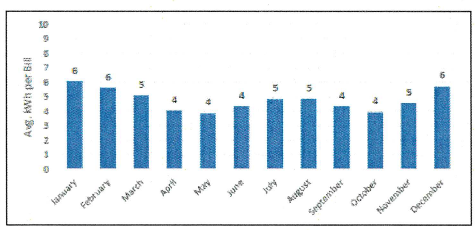
Large School Avg. Usage by Month



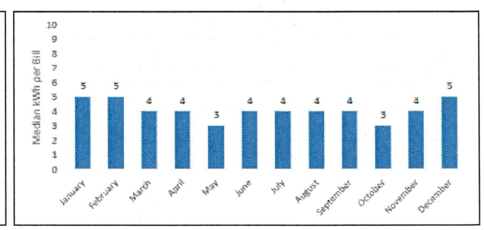
Large School Median Usage by Month



Street/Traffic Lighting Bill Distribution

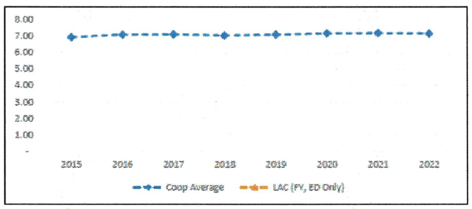


Street/Traffic Lighting Avg. Usage by Month

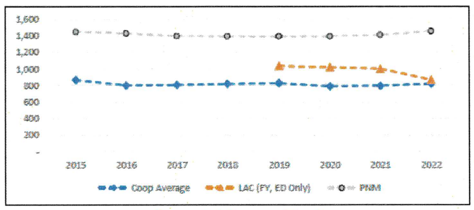


Street/Traffic Lighting Median Usage by Month

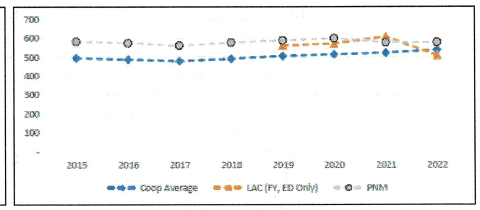
18 Appendix B – Additional Benchmark Metrics



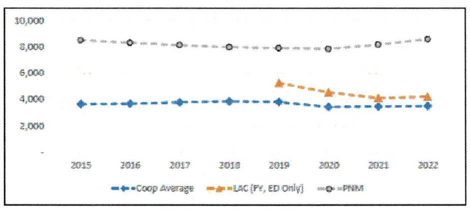
Customers per Mile of Distribution Line



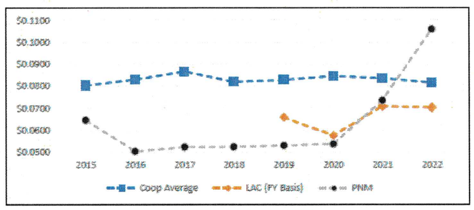
Average kWh/Customer/Month



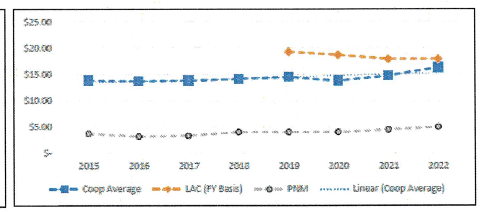
Average kWh/Customer/Month - Residential



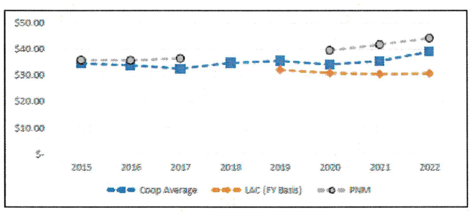
Average kWh/Customer/Month - Non-Residential



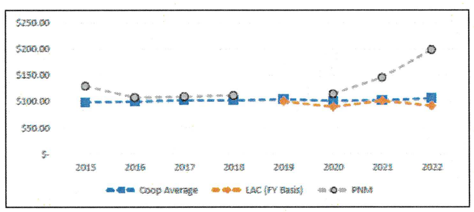
Average Power Cost per kWh



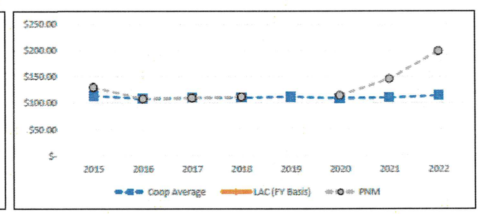
Average Distribution Costs per Customer



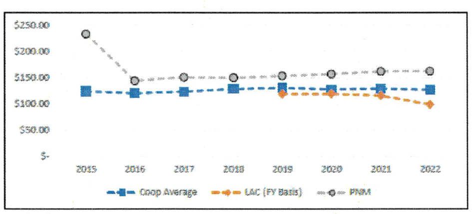
Monthly O&M and A&G Expense per Customer - Excluding Power



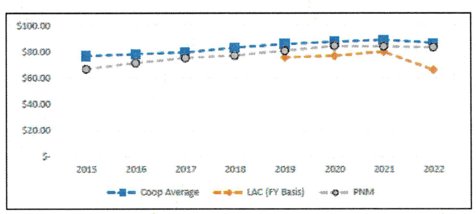
Monthly O&M and A&G Expense per Customer - Including Power



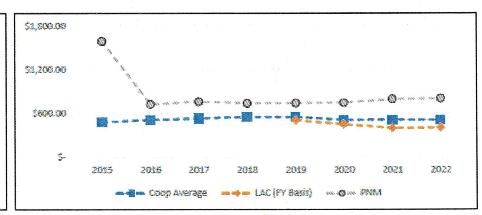
Total Operating Expense and Interest Payments per Customer



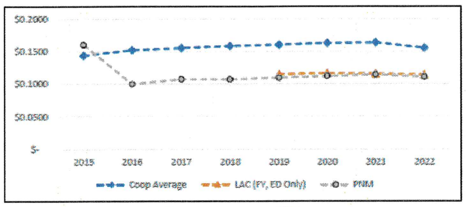
Average Revenue / Customer / Month



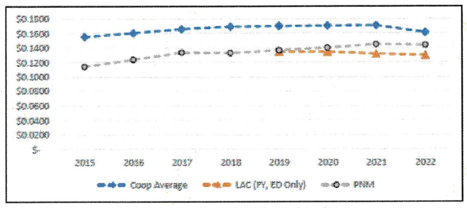
Average Revenue / Customer / Month - Residential



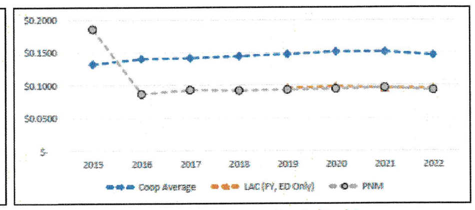
Average Revenue / Customer / Month - Non-Residential



Average Revenue per kWh



Average Revenue per kWh - Residential



Average Revenue per kWh - Non-Residential

19 Appendix C – Demand Charge Example

Example of Subsidy Received by Customer – No Demand Charge

	Customer Statistics			Cost Incurred by Utility				Cost Recovery - $5 Fixed Charge			Subsidy
	kWh	kW	Load Factor	Demand	Volumetric	Customer	Total	Fixed	Commodity	Total	Received/(Paid)
January	1,006	5.25	0.53	$ 20.94	$ 50.30	$ 5.50	$ 76.74	$ 5.00	$ 49.52	$ 54.52	$ 22.22
Feburary	1,113	4.82	0.64	20.94	55.65	5.50	82.09	5.00	54.79	59.79	22.30
March	800	4.83	0.46	20.94	40.00	5.50	66.44	5.00	39.38	44.38	22.06
April	750	4.76	0.44	20.94	37.50	5.50	63.94	5.00	36.92	41.92	22.02
May	810	5.21	0.43	20.94	40.50	5.50	66.94	5.00	39.87	44.87	22.07
June	1,100	6.18	0.49	20.94	55.00	5.50	81.44	5.00	54.15	59.15	22.29
July	1,250	6.87	0.51	20.94	62.50	5.50	88.94	5.00	61.53	66.53	22.41
August	1,506	6.98	0.60	20.94	75.30	5.50	101.74	5.00	74.13	79.13	22.61
September	1,174	6.87	0.47	20.94	58.70	5.50	85.14	5.00	57.79	62.79	22.35
October	859	5.55	0.43	20.94	42.95	5.50	69.39	5.00	42.28	47.28	22.11
November	782	5.36	0.41	20.94	39.10	5.50	65.54	5.00	38.49	43.49	22.05
December	948	5.27	0.50	20.94	47.40	5.50	73.84	5.00	46.66	51.66	22.18
Total	**12,098**			**$ 251.28**	**$ 604.90**	**$ 66.00**	**$ 922.18**	**$ 60.00**	**$ 595.52**	**$ 655.52**	**$ 266.66**
Maximum Demand:		**6.98**									

Class Statistics	
Customers	100
Demand (Non-Coincident kW)	550
Usage (kWh)	1,120,000
Total Costs Recovered	
Customer Classified	$ 6,600
Demand Costs	2,031
Commodity Costs	52,500
Unit Costs	
Customer Classified Costs per Bill	$ 5.50
Demand Costs per kW	3.00
Commodity Costs per kWh	0.050
Rates	
Customer Charge	$ 5.00
Usage Charge	0.049

Example of Subsidy Received by Customer – Demand Charge

	Customer Statistics			Cost Incurred by Utility				Billed - $5 Fixed Charge, $2.75 Demand Charge				Subsidy
	kWh	kW	Load Factor	Demand	Volumetric	Customer	Total	Fixed	Demand	Varable	Total	Received/(Paid)
January	1,006	5.25	0.53	$ 20.94	$ 50.30	$ 5.50	$ 76.74	$ 5.00	$ 22.69	$ 50.32	$ 78.01	$ (1.27)
Feburary	1,113	4.82	0.64	20.94	55.65	5.50	82.09	5.00	22.69	55.67	83.36	(1.27)
March	800	4.83	0.46	20.94	40.00	5.50	66.44	5.00	22.69	40.02	67.70	(1.26)
April	750	4.76	0.44	20.94	37.50	5.50	63.94	5.00	22.69	37.52	65.20	(1.26)
May	810	5.21	0.43	20.94	40.50	5.50	66.94	5.00	22.69	40.52	68.20	(1.26)
June	1,100	6.18	0.49	20.94	55.00	5.50	81.44	5.00	22.69	55.02	82.71	(1.27)
July	1,250	6.87	0.51	20.94	62.50	5.50	88.94	5.00	22.69	62.53	90.21	(1.27)
August	1,506	6.98	0.60	20.94	75.30	5.50	101.74	5.00	22.69	75.33	103.02	(1.28)
September	1,174	6.87	0.47	20.94	58.70	5.50	85.14	5.00	22.69	58.73	86.41	(1.27)
October	859	5.55	0.43	20.94	42.95	5.50	69.39	5.00	22.69	42.97	70.65	(1.26)
November	782	5.36	0.41	20.94	39.10	5.50	65.54	5.00	22.69	39.12	66.80	(1.26)
December	948	5.27	0.50	20.94	47.40	5.50	73.84	5.00	22.69	47.42	75.11	(1.27)
Total	**12,098**			**$ 251.28**	**$ 604.90**	**$ 66.00**	**$ 922.18**	**$ 60.00**	**$ 272.22**	**$ 605.16**	**$ 937.38**	**$ (15.20)**
Maximum Demand:		**6.98**										

Class Statistics	
Customers	100
Demand (Non-Coincident kW)	550
Usage (kWh)	1,120,000
Total Costs Recovered	
Customer Classified	$ 6,600
Demand Costs	24,374
Commodity Costs	52,500
Unit Costs	
Customer Classified Costs per Bill	$ 5.50
Demand Costs per kW/Month	3.00
Commodity Costs per kWh	0.050
Rates	
Customer Charge	$ 5.00
Demand Charge	$ 3.25
Usage Charge	0.050

20 Appendix D - Recommended TOU Rate Structure

On-Peak Hours Designation:
All Months, 5-11 PM

Standard Rate (July 2024)	0.1413
Off-Peak Rate	**0.0950**
Off-Peak Recovery	3,858,960
On-Peak Rate	**0.2405**
On-Peak Recovery	4,370,061
On/Off-Peak Ratio	2.53

					Average											
On-Peak Usage %	**35.0%**	**34.0%**	**33.0%**	**32.0%**	**31.0%**	**30.00%**	**29.00%**	**28.00%**	**27.00%**	**26.00%**	**25.00%**	**24.00%**	**23.00%**	**22.00%**	**21.00%**	**20.00%**
On-Peak kWh	193	187	182	176	171	165	160	154	149	143	138	132	127	121	116	110
Off-Peak kWh	357	363	368	374	379	385	390	396	401	407	412	418	423	429	434	440
Total kWh	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**	**550**
Current Bill (July 2024 Rates)	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32	$ 90.32
TOU Bill	92.92	92.05	91.32	90.45	89.72	88.85	88.12	87.25	86.52	85.65	84.92	84.05	83.32	82.45	81.72	80.85
Monthly Increase/(Decrease)	2.60	1.73	1.00	0.13	(0.60)	(1.47)	(2.20)	(3.07)	(3.80)	(4.67)	(5.40)	(6.27)	(7.00)	(7.87)	(8.60)	(9.47)
Annual Increase/(Decrease)	**31.20**	**20.76**	**12.00**	**1.56**	**(7.20)**	**(17.64)**	**(26.40)**	**(36.84)**	**(45.60)**	**(56.04)**	**(64.80)**	**(75.24)**	**(84.00)**	**(94.44)**	**(103.20)**	**(113.64)**

21 Appendix E - Recommended Residential Demand Structure

Residential Demand Rate Recommendation

- Phase in of Demand Charge
- No Ratchet
- Demand Measured at "On-Peak" hours:
  November-February 9-10 AM, 6-10 PM
  June-September 2-9 PM
- Assumes Demand Charge will be Revenue Neutral.

- Rates:

	Current (Oct '23)	Year 1	Year 2	Year 3
Service Charge (per Bill)	12.00	$ 12.00	$ 12.00	$ 12.00
Commodity Charge (per kWh)	0.1282	0.1272	0.1261	0.1251
Demand Charge (per kW) (Hourly)	-	1.00	2.00	3.00

Example Residential Customer

	Current (Oct '23)	Year 1	Year 2	Year 3
Usage	500	500	500	500
Base Demand Level (KW) at Peak Hours	1.39	1.39	1.39	1.39
Bill - No Demand Reduction	**$ 76.10**	**$ 76.99**	**$ 77.83**	**$ 78.72**
Impact of Switching Use off Peak				
Washing Machine @ 0.9 kW, 45 Minutes				
Adjusted kW at Peak Hours	0.71	0.49	0.49	0.49
Total Bill	$ 76.10	$ 76.09	$ 76.03	$ 76.02
Savings	$ -	$ 0.90	$ 1.80	$ 2.70
Electric Water Heater @ 4.5kW, 10 Minutes				
Adjusted kW at Peak Hours	0.64	0.64	0.64	0.64
Total Bill	$ 76.10	$ 76.24	$ 76.33	$ 76.47
Savings	$ -	$ 0.75	$ 1.50	$ 2.25
Air Conditioner @ 4.0kW, 15 Minutes				
Adjusted kW at Peak Hours	0.39	0.39	0.39	0.39
Total Bill	$ 76.10	$ 75.99	$ 75.83	$ 75.72
Savings	$ -	$ 1.00	$ 2.00	$ 3.00
Hair Dryer @ 0.12 kW, 10 Minutes				
Adjusted kW at Peak Hours	1.37	1.37	1.37	1.37
Total Bill	$ 76.10	$ 76.97	$ 77.79	$ 78.66
Savings	$ -	$ 0.02	$ 0.04	$ 0.06

PREPARED BY GDS ASSOCIATES, INC.

Los Alamos County

Electric Cost of Service and Rate Study

May 1, 2024

GDS Associates, Inc.
ENGINEERS & CONSULTANTS