Electric Rate Study

Final Report

September 2023

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MOUNTAIN LAKE
UTILITIES

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September 14, 2023

Mountain Lake Utility Commission
903 3rd Ave
PO Box C
Mountain Lake, MN 56159

Members of the Mountain Lake Utility Commission:

Missouri River Energy Services (MRES) is pleased to submit this electric rate study report for Mountain Lake Municipal Utilities. This study had four principal objectives:

- To determine whether estimated total revenues will be sufficient to cover estimated revenue requirements and provide a reserve for replacements and contingencies
- To determine the cost to serve each customer class
- To design retail rates for the various classes, including analyzing the power cost adjustment (PCA) base and the calculation methodology
- To review the competitive position of Mountain Lake through utility rate comparisons

The key rate study recommendations include:
- Implement a three-year rate plan with eight percent overall increases each year
- Maintain the PCA calculation and the PCA base
- Maintain the qualifications for the Large Commercial class. All non-residential customers with a peak demand of 20 kW in three or more months out of the previous 12 months are included in this class.

The proposed rates were designed to recover operating expenses, fund capital expenditures and the additional debt service obligation while increasing reserves throughout the study period. Section 4 of this report contains all of the recommendations, **but further adjustments to the rates may be necessary in future years if operating costs, system characteristics, or the financial needs of the utility change drastically.**

MRES appreciated the opportunity to prepare this study for Mountain Lake Municipal Utilities and would like to thank your staff for its valuable assistance.

Respectfully submitted,

Missouri River Energy Services

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MOUNTAIN LAKE MUNICIPAL UTILITIES
ELECTRIC RATE STUDY
TABLE OF CONTENTS

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This rate study was completed in accordance with the agreed upon terms as set forth in the Proposal Letter and Exhibit A, Scope of Services between Missouri River Energy Services and Mountain Lake. In completing this study, Missouri River Energy Services has relied on the data and materials provided by Mountain Lake and others to be accurate, and has not independently verified their accuracy. The analysis, conclusions, and recommendations contained in this report constitute the opinions of Missouri River Energy Services based on the data and materials provided. Final responsibility for the implementation of the recommendations in this report rests with the Mountain Lake staff and the governing board.

SECTION 1

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SECTION 1 – RATE STUDY INTRODUCTION AND POWER REQUIREMENTS

INTRODUCTION

The Mountain Lake Municipal Utilities (Mountain Lake), under the direction of the Utility Commission, provides electric service to about 1,060 customers. Mountain Lake is a member of Central Municipal Power Agency/Services (CMPAS). CMPAS provides several services to Mountain Lake, including consulting and scheduling services for power supply and transmission service. Missouri River Energy Services (MRES), located in Sioux Falls, South Dakota, was engaged to perform a review of the Mountain Lake electric rates, including an analysis of revenues and revenue requirements for the study period of 2023 to 2027, the allocation of costs to serve each customer class based on a Test Year, and the design of retail rates.

The study was prompted, in part, by the need to evaluate the adequacy of revenues due to increasing power supply and operating costs along with an additional debt service obligation. The study also analyzed current and projected reserve levels for the study period to determine if reserves would maintain the optimal level determined by Mountain Lake staff. Furthermore, the study was to determine if each class is paying an appropriate share of the costs, and the study reviewed the current qualifications for each class.

KEY DEFINITIONS

In this report, there are several key electric utility terms used. Following are definitions for some of these terms:

- Peak Demand (kW) – The maximum rate of power delivery, measured in a defined time period such as 30 minutes, expressed in 1,000 watt units.
- Energy (kWh) – Power multiplied by time. The usage of ten 100 watt light bulbs for one hour equals one kWh. One thousand kWh equals one megawatt-hour (MWh).
- Load Factor – Equals average demand for a given time period (kWh per hour) divided by peak demand. A higher load factor indicates more consistent and efficient use of power and the distribution system. Customers such as grocery stores and medical facilities often have higher load factors, while schools, grain elevators, and manufacturing facilities with only one shift or intermittent equipment usage often have lower load factors.
- Single Phase – The customer is served from one voltage source. This type of service is used for most residential and smaller commercial customers.
- Three Phase – The customer is served by three voltage sources. This is used by commercial customers that have larger loads and/or have large motors.

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ENERGY REQUIREMENTS

The table below shows annual peak demand, sum of monthly peak demands, and energy requirements for Mountain Lake from 2020 to 2027. In 2021 and 2022, Mountain Lake's energy requirements increased by 6.9% due to increased usage in the large commercial class and some extreme weather conditions increasing the heating and air conditioning load. The study forecasts that energy requirements will decrease by 0.6% in 2023 due to weather normalization and then increase by 0.25% per year from 2024 through 2027. The system annual peak typically occurs in the summer months, and the annual peak is forecasted to be in July from 2023 through 2027. In the past three years, the annual peak has averaged 6,271 kW, while the average monthly peak was only 4,720 kW. The higher summer peaks are due to air conditioning usage by residential and commercial customers.

Historical and Forecasted Wholesale Energy Requirements and Retail Sales						
	Year	Annual Peak Demand (kW)	Sum of Monthly Demands (kW)	% change	Energy Requirements (MWh)	% Change
Actual	2020	6,463 July	59,081		27,376	
	2021	5,835 June	55,177	(6.6%)	28,020	2.4%
	2022	6,515 July	55,671	0.9%	29,270	4.5%
Forecast	2023	6,476 July	56,342	(0.6%)	29,100	(0.6%)
	2024	6,492 July	56,483	0.3%	29,173	0.3%
	2025	6,508 July	56,624	0.3%	29,246	0.3%
	2026	6,525 July	56,766	0.3%	29,319	0.3%
	2027	6,541 July	56,908	0.3%	29,392	0.3%

The chart on the following page shows the total forecasted energy requirements from 2023 to 2027 broken down by supplier. Mountain Lake receives an allocation from the Western Area Power Administration (WAPA), which operates several hydroelectric plants on the Missouri River. The allocation is forecasted to be approximately 21% of Mountain Lake's energy requirements from 2023 through 2027. Mountain Lake also has a contract for 600 kW from the Nebraska City 2 (NC2) power plant, which is located about 50 miles south of Omaha, Nebraska. Mountain Lake is expected to receive about 14% of its requirements from NC2. The other power supply contracts include the following: WPPI Energy supplying about 14%; the 5x16 contract with Citigroup, supplying nearly 15%; and the Midcontinent Independent System Operator (MISO) market purchases supplying approximately 26% of the energy requirements. Mountain Lake owns an 8 MW diesel generation plant and a wind turbine, which was constructed in 2007. The municipally-owned generation is forecasted to supply over 10% of Mountain Lake's energy needs. The purchased power and local generation costs are further discussed in Section 2.

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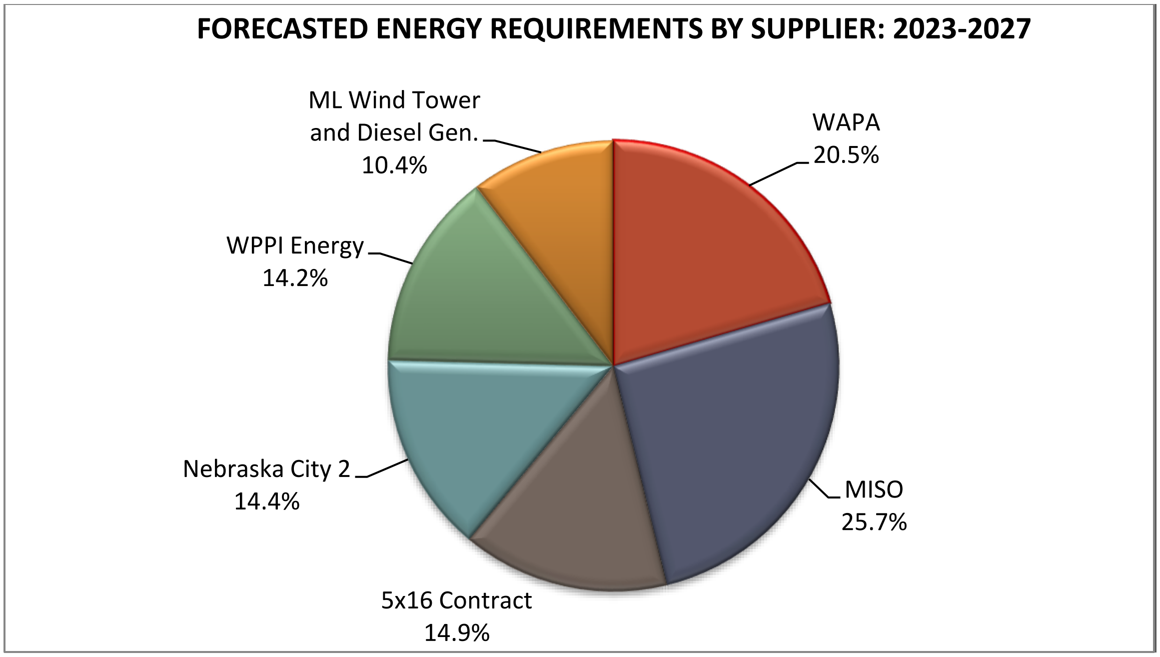
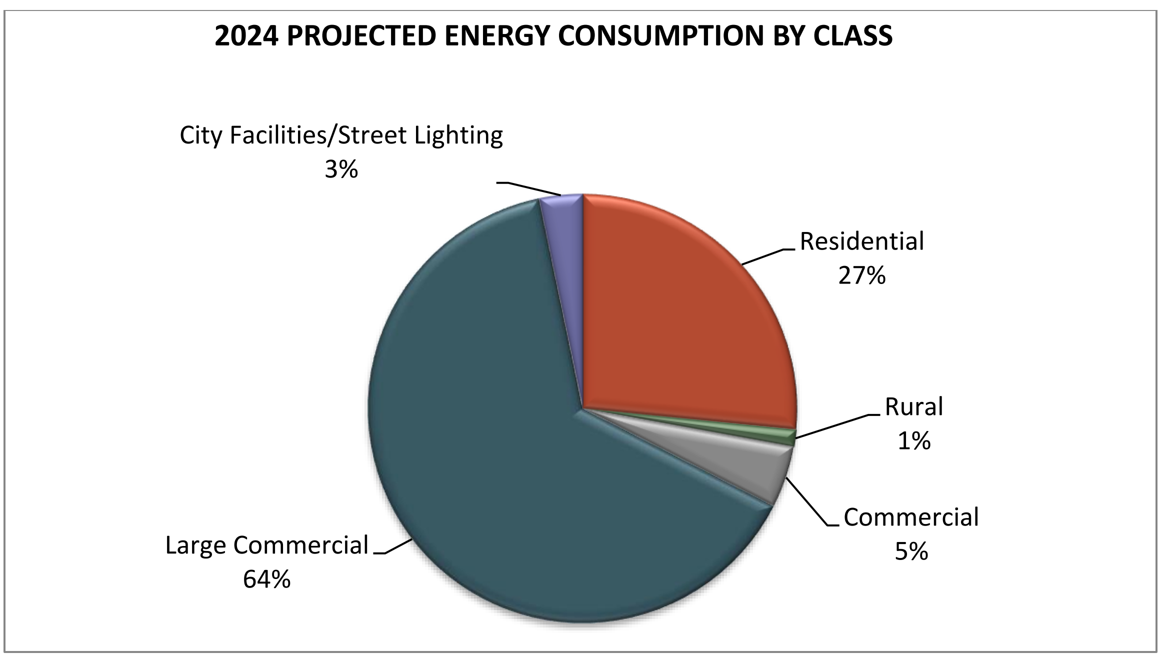


PROJECTED ENERGY CONSUMPTION BY CLASS

The projected energy consumption by class for 2024 is shown in the pie chart below. The breakdown shows that Residential customers, including the rural class, are projected to consume 28% of the energy requirements. The average consumption by the Residential class in other regional utilities is approximately 42% of the total system energy consumption. The Large Commercial class is projected to have 64% of the energy sales in 2024 but only 4% of the total customers. City facilities include the water and wastewater utilities' consumption.



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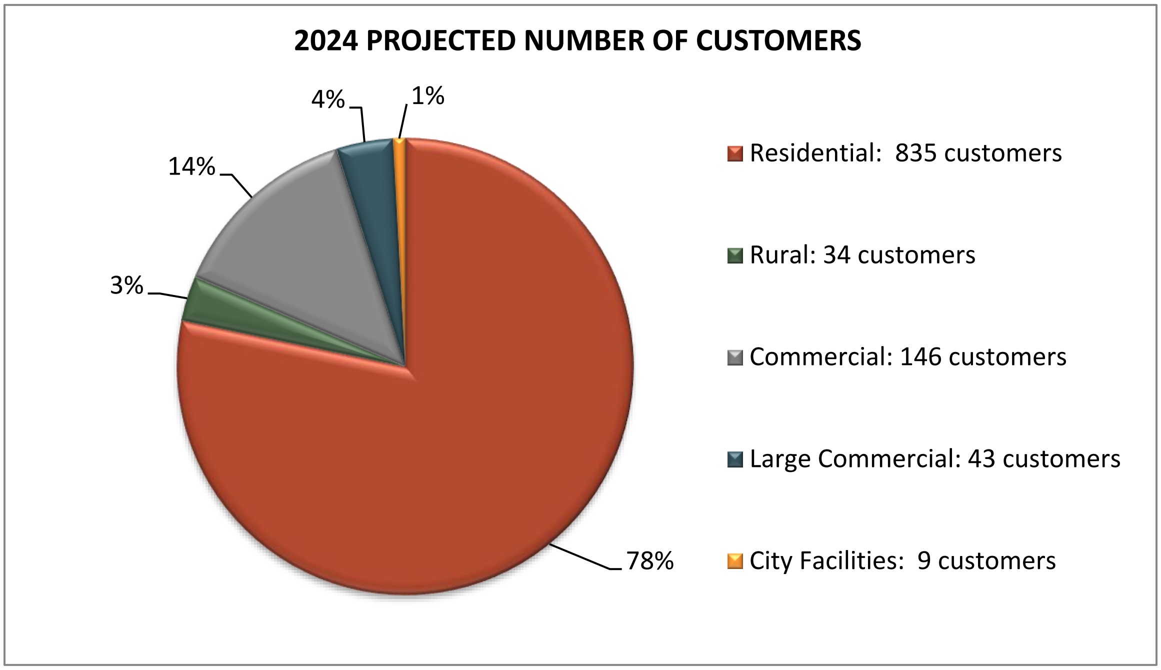
PROJECTED NUMBER OF CUSTOMERS BY CLASS

Based on discussions with staff, Mountain Lake expects two additional Large Commercial customers in 2024 and two residential customers per year during the study period. However, the number of customers may vary slightly from year to year. The chart below breaks down the projected number of customers by class for 2024. The Residential class has 78% of the total number of customers.



SECTION 2

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SECTION 2 – PROJECTED NET INCOME AND CASH RESERVES

MRES worked with Mountain Lake staff to estimate the annual revenues and the expenditures, "revenue requirements", for the five-year study period of 2023 to 2027. Revenue requirements must be compared to revenues to determine whether the electric utility will recover all of its costs and provide a margin for a reserve for system replacements, contingencies, and rate stabilization. The analyses and assumptions used in developing these estimates are described on the following pages. Exhibits 2-A and 2-B at the end of this section present the projected net income and cash reserves. Exhibit 2-C provides details on the historical and projected purchased power, transmission, local production costs, and annual power cost adjustment.

ESTIMATED REVENUES

Estimated revenues consist of metered electric sales, other operating revenue, and non-operating revenues. Metered sales were estimated based on current retail rates along with the demand and energy forecasts and the customer class growth projections discussed in Section 1. The metered sales revenues include the power cost adjustments that are projected at zero from 2023 through 2025 before increasing to $0.0018 per kWh by 2027, as shown in Exhibit 2-C.

Other operating revenue includes late payment, reconnect, and shut off fees, hanger notices, and conservation improvement plan (CIP) revenue. Other operating revenues are projected to average $59,000.

Non-operating revenue consists of investment income from cash reserve, municipally-owned transmission line revenue, and refunds. Non-operating revenues are projected to decrease from $403,000 in 2023 to $191,100 by 2027. The decrease is due to a lower cash balance and projected interest rate decreasing from 4.0% in 2023 to 1.5% by 2027. The payment for the transmission line also decreases over time as the asset depreciates.

ESTIMATED REVENUE REQUIREMENTS

The revenue requirements of the electric utility consist of purchased power, transmission service, and local generation expenses, other operating expenses, transfers to the general fund, debt service, and capital expenditures. Revenue requirement projections were based on historical operating statements from 2019 through 2022, the operating budget for 2023, estimated purchased power expenses, and discussions with Mountain Lake staff.

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Purchased Power, Transmission Service, and Municipally-Owned Generation Expenses

The wholesale purchased power and transmission service expenses, along with the municipally-owned wind turbine and diesel generation plant production costs, are based on several assumptions, including the energy requirements as outlined in Section 1. Exhibit 2-C provides details on the historical and projected purchased power supply and transmission service costs by supplier along with the local generation costs.

WAPA Wholesale Power Rates

WAPA more than doubled its rates from 2004 through 2010 due to prolonged drought conditions. Due to the drought conditions receding along with other reasons, WAPA held rates steady from 2010 through 2016 at a composite rate of $33.25 per MWh. In 2017 and 2018, WAPA reduced the composite rate by approximately 30%, resulting in a total savings of around $60,000 annually for Mountain Lake. In 2018, the base component of the firm power demand and energy rates increased to $24 per MWh and the drought adder decreased to zero. The new WAPA contract that began in January 2021 eliminated the wheeling credit of $1 per MWh resulting in a 4.8% increase.

In early 2022, WAPA began a public rate process to determine rates for January 1, 2023. WAPA published a Federal Register Notice (FRN) in May 2022 indicating that rates would increase to a composite rate of $27.91 per MWh, or 16.4%, in 2023 due to ongoing drought conditions in the Missouri River Basin, increasing wholesale energy purchase prices, increasing operations and maintenance cost projections from the federal hydropower agencies, and the February 2021 polar vortex event. The FRN was approved in late 2022 and rate notifications were sent December 2022. WAPA recently indicated rising operating costs are creating additional upward rate pressure while future drought concerns have lessened. The study assumes an additional 2 mill increase, or about 7.4% in 2025.

WAPA Actual and Projected Wholesale Demand and Energy Rates			
Year	Demand Rate ($/kW-month)	All Energy ($/MWh)	Wheeling Credit ($/kWh)
2010-2016 (Actual)	$7.65	$19.05	($0.001)
2017 (Actual)	$6.50	$16.18	($0.001)
2018-2022 (Actual)	$5.25	$13.27	($0.001)
2023 (Actual)	$6.20	$15.27	-
2024 (Projected)	$6.20	$15.27	-
2025-2027 (Projected)	$6.65	$16.35	-

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Other Power Supply Costs

Mountain Lake is projected to purchase nearly 15% of its energy requirements from a 5x16 On Peak contract through Citi Group. The Citigroup contract replaced the NextEra 5x16 contract that expired at the end of 2020. The new contract is at a lower cost of $35.50 per MWh while annual energy purchases increased from 2,044 MWh to 4,350 MWh.

Mountain Lake also has a contract to purchase 600 kW of base load power from the NC2 coal plant that became operational in 2009. NC2 is considered a base load resource, which means Mountain Lake receives power from the plant 24 hours a day, every day of the year except for the hours the plant is not operating. The study assumed Mountain Lake would purchase about 4,200 MWh per year from NC2 at an estimated price of $39.00 per MWh in 2023 increasing to $42.20 per MWh by 2027. To diversify its resource mix, Mountain Lake contracted with WPPI Energy in Sun Prairie, Wisconsin, to receive over 14% of its energy requirements, or 4,150 MWh per year, from the Point Beach Nuclear Plant in Two Rivers, Wisconsin. The WPPI Energy contract is estimated to increase from $69.00 per MWh in 2023 to $74.70 per MWh by 2027.

Mountain Lake is projected to produce over 10% of its own energy from the municipally-owned wind turbine and a seldom run diesel generation plant. The remaining energy requirements, or approximately 26%, are projected to be purchased in the MISO market at an estimated average price of $34.50 per MWh. Finally, Mountain Lake has a contract to purchase a small quantity of energy from the Wolf Wind Project, which is then sold back into the MISO market at a net cost estimated at $20,000 per year.

Transmission Service Costs

Transmission service is purchased from the MISO market in the ITC Midwest pricing zone. The cost of transmission services is estimated at $25.00 per MWh in 2023 and gradually increasing to $28.10 per MWh by 2027, or 3% per year. Transmission costs have continued to increase in the last several years due to ITC Midwest seeking cost recovery for their significant capital investments that have been made to the regional transmission grid. Finally, Mountain Lake pays CMPAS for energy scheduling, member dues, agency fixed costs, and contract administration. In 2019, the member dues were reduced from $2,500 per month to $1,500 per month. The scheduling charge has also decreased slightly from $0.55 per MW to $0.52 per MW.

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Total Purchased Power, Transmission Service, and Municipally-Owned Generation Costs

Total power supply and transmission costs are expected to increase an average of 3.4% per year from 2023 through 2027. The table below shows the estimated purchased power and transmission expenses by supplier. Total CMPAS charges below include capacity sales that offset member dues, scheduling charges, and administrative fees.

Estimated Purchased Power, Local Generation, and Transmission Expenses									
Year	WAPA	Nebraska City 2	Citigroup 5x16	WPPI Energy	MISO Market & Wolf Wind	Mt. Lake Total Local Generation	Trans-mission	CMPAS Charges/ Capacity Rev.	Total Cost
2023	$162,743	$163,800	$154,278	$286,350	$109,604	$105,545	$726,500	($63,895)	$1,644,926
2024	$163,241	$167,076	$154,278	$292,077	$114,115	$90,802	$750,168	$35,503	$1,767,260
2025	$174,714	$170,418	$154,278	$297,919	$120,084	$91,066	$774,608	$30,334	$1,813,420
2026	$174,714	$173,826	$154,278	$303,877	$125,683	$91,338	$799,608	$29,772	$1,853,331
2027	$174,714	$177,302	$154,278	$309,954	$131,535	$91,618	$825,901	$29,810	$1,895,113

The next table breaks down the cost per MWh from the various power supply sources and the transmission provider. The total cost per MWh is projected to increase by 7.3% in 2024 and then increase by an average of 2.1% per year from 2025 through 2027. The increase in 2024 is mostly due to lower capacity sales which offset purchased power costs.

Estimated Purchased Power and Transmission Prices per MWh and Total Cost per MWh (includes Congestion and Losses where applicable)									
Year	WAPA	Neb. City 2	Citigroup 5x16	WPPI Energy	MISO Market	Mt. Lake Wind	Trans-mission	Total Cost per MWh	% Increase
2023	$27.20	$39.00	$35.50	$69.00	$32.50	$27.00	$25.00	$56.50	
2024	$27.20	$39.80	$35.50	$70.40	$33.50	$22.00	$25.80	$60.60	7.3%
2025	$29.20	$40.60	$35.50	$71.80	$34.50	$22.00	$26.50	$62.00	2.3%
2026	$29.20	$41.40	$35.50	$73.20	$35.50	$22.00	$27.30	$63.20	1.9%
2027	$29.20	$42.20	$35.50	$74.70	$36.60	$22.00	$28.10	$64.50	2.0%

Other Operating Expenses

Other operating expenses include production, distribution, administrative and general, and depreciation expense. Most operating expenses are expected to increase by 3% annually and depreciation expense is based on planned capital expenditures during the study period.

Transfer to the General Fund and Discounted Cost Electric Service

The electric utility is expected to transfer $120,000 per year to the City of Mountain Lake's general fund from 2023 through 2027, or 3.7% of operating revenues.

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The 2020 American Public Power Association national survey indicated the median percentage of transfers and related payments as a percentage of operating revenues was 6.1%. Meanwhile, in a study of 89 area municipal utility financial statements, MRES found that the median level of transfers and donated services as a percentage of operating revenues was 5.2% of operating revenues. Transfers and related payments can include payments in lieu of taxes, franchise fees, free or reduced cost city and enterprise services, interest free loans to other entities, use of electric utility employees, and use of vehicles, equipment, materials, and supplies. Contributions from other city funds or entities to the electric utility are netted against the amount the electric utility provides.

Debt Service

In 2007, Mountain Lake received Clean Renewable Energy Bonds (CREBs) from the U.S. Internal Revenue Service to finance the municipally-owned wind turbine over 15 years. The $2.06 million issuance was paid off earlier this year. Additional bonds were issued in 2017 to fund upgrades to the local generation and substation and that issuance is projected to be paid in full in 2036. In 2021, Mountain Lake issued $1.74 million to repair issues found with one of the units used for local reliability. It was later discovered that additional repairs were needed to several of the units. Mountain Lake decided to pursue new generation that would replace all of the existing units. The study assumes that Mountain Lake would issue bonds for an additional $12 million in 2025 that would help fund the new generation.

Outstanding Debt Balances and Payments						
Bond Series	**Purpose**	**Dec. 31, 2022 Outstanding Balance**	**2023-2027 Principal Payments**	**2023-2027 Interest Expense**	**Dec. 31, 2027 Outstanding Balance**
2007B	ML Wind Turbine	$128,750	$128,750	N/A	$-
2017A	NESHAP/Substation	$2,880,000	$745,000	$487,818	$2,135,000
2021A	Generation Repair	$1,740,000	$930,000	$137,600	$810,000
2025A	New Generation	$-	$667,901	$1,413,982	$11,332,099
	Total	$4,748,750	$2,471,651	$2,039,400	$14,277,099

Capital Expenditures

Based on Mountain Lake's five-year capital improvement plan and discussions with staff, the revenue financed capital expenditures are expected to total approximately $857,200 from 2023 to 2027. The following is a breakdown of the revenue-financed capital expenditures:

- Distribution System Improvements $410,000
- Vehicles/Equipment $160,800
- Local Generation $145,000
- Routine Maintenance $141,400

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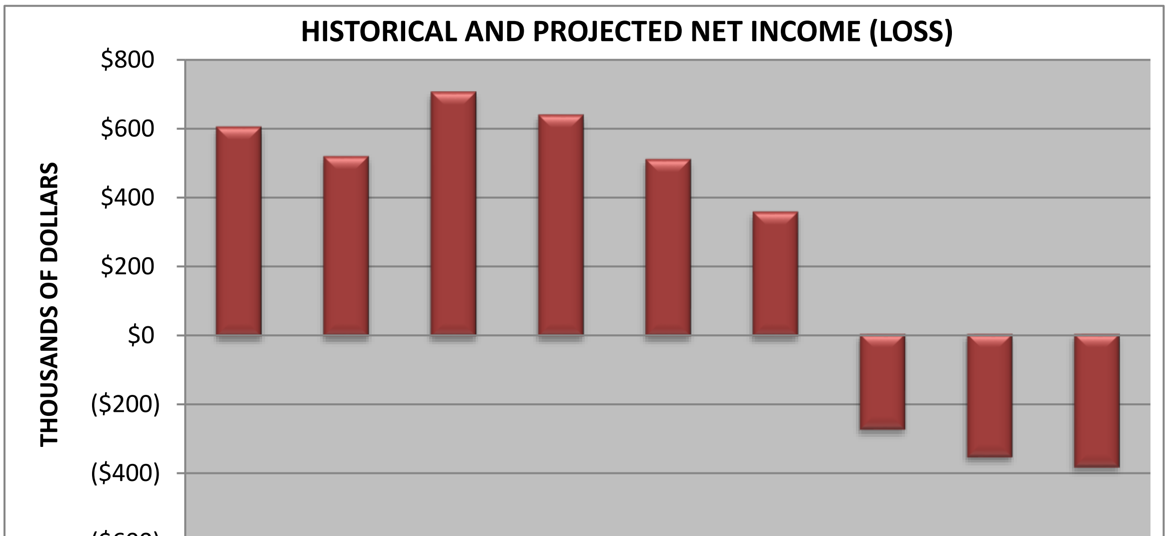
In addition to the revenue financed capital expenditures, Mountain Lake is expected to spend an additional $14 million on 8 MW of generation. Mountain Lake currently has 5.9 MW of generation that was built in the 1950s. However, it is in need of several repairs and upgrades that could make the generation no longer feasible to operate in the coming years. The study assumes the existing generation would be retired and 8 MW of new generation would be built at a new site. The additional capacity of the new generation could be sold into the MISO market to help offset some costs although the capacity market has been very volatile in recent years.

SUMMARY OF RESULTS

Based on the assumptions described in this section, MRES has projected the net income and cash reserves as shown in Exhibits 2-A and 2-B. The projections indicate that under current rates, the utility would begin seeing net losses in 2025.



	2019	2020	2021	2022	2023	2024	2025	2026	2027
Current	$603	$517	$704	$637	$508	$355	($271)	($352)	($381)

The graph on the following page shows total unrestricted cash reserves under current rates. Cash reserves have increased from nearly $2.2 million in 2019 to over $3.2 million at the end of 2022. Cash is projected to continue increasing until 2024 and peak around $3.8 million. Cash would then rapidly decrease based on the new debt service payments that are expected that year. The utility has an additional $1.8 million in restricted reserves that would be used to help fund the new generation project in 2025.

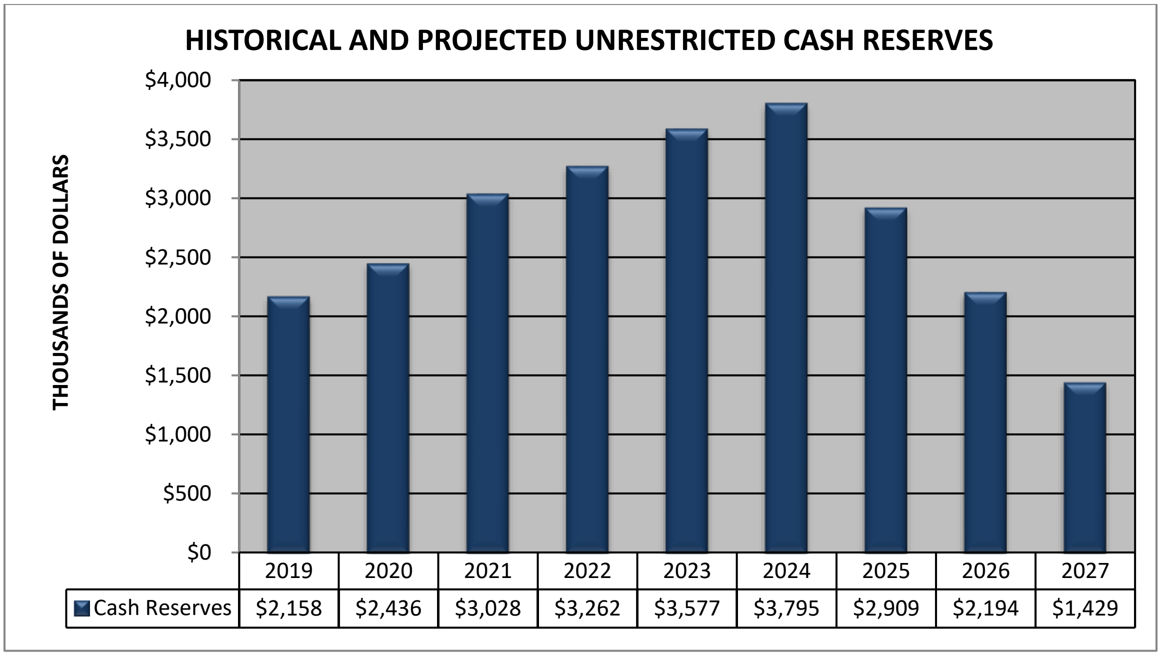

HISTORICAL AND PROJECTED UNRESTRICTED CASH RESERVES
THOUSANDS OF DOLLARS
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
2019
2020
2021
2022
2023
2024
2025
2026
2027
Cash Reserves
$2,158
$2,436
$3,028
$3,262
$3,577
$3,795
$2,909
$2,194
$1,429

Exhibit 2-A

Mountain Lake Public Utilities
Electric Utility Operating Results
Current Rates

	Historical				Projected				
	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total System Retail kWh Sales	26,770,488	26,449,663	27,366,597	28,196,733	28,115,942	28,186,232	28,256,697	28,327,339	28,398,158
kWh % Change from Year to Year		-1.2%	3.5%	3.0%	-0.3%	0.3%	0.2%	0.2%	0.2%
OPERATING REVENUES									
Metered Electric Sales	2,793,522	2,729,948	2,753,337	3,095,006	$ 3,121,258	$ 3,130,100	$ 3,137,574	$ 3,159,778	$ 3,204,903
Other Operating Revenues	144,245	154,136	254,885	81,982	60,319	57,951	58,064	58,397	59,074
Total Operating Revenues	2,937,767	2,884,084	3,008,222	3,176,988	3,181,577	3,188,051	3,195,638	3,218,174	3,263,977
OPERATING EXPENSES									
Purchased Power & Transmission	1,333,196	1,363,797	1,385,338	1,401,165	1,539,381	1,676,459	1,722,354	1,761,994	1,803,495
Production	59,712	57,064	84,235	133,991	100,700	103,721	106,833	110,038	113,339
Distribution	367,389	438,380	283,860	416,792	523,027	479,618	494,007	508,827	524,092
Administrative & General	204,858	207,008	269,183	260,325	294,590	302,617	305,886	314,553	323,479
Depreciation Expense	366,497	365,069	367,762	352,140	359,751	365,686	371,689	376,084	380,715
Total Operating Expense	2,331,652	2,431,318	2,390,378	2,564,413	2,817,449	2,928,101	3,000,768	3,071,494	3,145,120
NET OPERATING INCOME	606,115	452,766	617,844	612,575	364,128	259,950	194,869	146,680	118,857
NON-OPERATING REVENUES (EXPENSES)									
Interest Income	26,121	22,975	7,422	10,254	201,757	160,790	83,660	43,639	32,917
Grant Income	-	13,136	-	-	-	-	-	-	-
Refunds and Reimbursements	55,071	68,058	109,858	54,684	3,200	3,200	3,200	3,200	3,200
CAPX Transmission Revenues	166,667	240,503	223,346	224,932	198,000	186,120	174,953	164,456	154,588
Interest Expense	(131,442)	(160,910)	(123,771)	(145,132)	(138,995)	(135,020)	(607,433)	(589,474)	(570,728)
Cost of Issuance	-	-	(10,972)	-	-	-	-	-	-
Total Non-Op. Revenue (Expense)	116,417	183,762	205,883	144,738	263,962	215,090	(345,619)	(378,180)	(380,023)
TRANSFER TO THE GENERAL FUND	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)
NET INCOME (LOSS)	**$ 602,532**	**$ 516,528**	**$ 703,727**	**$ 637,313**	**$ 508,090**	**$ 355,041**	**$ (270,750)**	**$ (351,500)**	**$ (381,166)**
Net Income (Loss) as a % of Op. Revenue	20.5%	17.9%	23.4%	20.1%	16.0%	11.1%	-8.5%	-10.9%	-11.7%
Debt Service Coverage					218%	186%	59%	51%	48%

Mountain Lake Public Utilities
Electric Utility Cash Reserves
Current Rates

Exhibit 2-B

	Historical				Projected				
	2019	2020	2021	2022	2023	2024	2025	2026	2027
NET INCOME (LOSS)	$ 602,532	$ 516,528	$ 703,727	$ 637,313	$ 508,090	$ 355,041	$ (270,750)	$ (351,500)	$ (381,166)
LESS: Revenue-Financed Capital Exp.	(72,802)	(302,523)	(327,835)	(134,087)	(228,333)	(178,053)	(180,095)	(131,834)	(138,939)
LESS: Generation Project							(14,000,000)		
ADD: 2025 Bond Revenues							12,000,000		
ADD: 2021A Revenues							1,782,253		
LESS: Bond Principal Payment 2025A							(213,961)	(222,520)	(231,420)
LESS: Bond Principal Payment 2021A					(180,000)	(180,000)	(185,000)	(190,000)	(195,000)
LESS: Bond Principal Payment 2017A					(15,000)	(145,000)	(190,000)	(195,000)	(200,000)
LESS: Bond Principal Payment 2007B					(128,750)				
ADD: Depreciation Expense					359,751	365,686	371,689	376,084	380,715
ADDITION (REDUCTION) IN RESERVES					**$ 315,758**	**$ 217,673**	**$ (885,864)**	**$ (714,770)**	**$ (765,811)**
Beginning of Year Unrestricted Reserves		$ 2,157,638	$ 2,435,816	$ 3,028,095	$ 3,261,672	$ 3,577,430	$ 3,795,104	$ 2,909,240	$ 2,194,470
Addition (Reduction) in Reserves		278,178	592,279	233,577	315,758	217,673	(885,864)	(714,770)	(765,811)
Addition to Restricted Fund									
End of Year Unrestricted Reserves	**$ 2,157,638**	**$ 2,435,816**	**$ 3,028,095**	**$ 3,261,672**	**$ 3,577,430**	**$ 3,795,104**	**$ 2,909,240**	**$ 2,194,470**	**$ 1,428,658**
Reserves as % of Operating Revenues	**73%**	**84%**	**101%**	**103%**	**112%**	**119%**	**91%**	**68%**	**44%**
Cash Balance									
Unrestricted	2,157,638	2,435,816	3,028,095	3,261,672	3,577,430	3,795,104	2,909,240	2,194,470	1,428,658
Designated									
Restricted for Debt Service			1,782,253	1,782,253	1,782,253	1,782,253	-	-	-
Restricted for Bond Reserve							-	-	-
Total Cash Reserves	$ 2,157,638	$ 2,435,816	$ 4,810,348	$ 5,043,925	$ 5,359,683	$ 5,577,357	$ 2,909,240	$ 2,194,470	$ 1,428,658

Exhibit 2-C

Mountain Lake Municipal Utilities									
Historical and Projected Purchased Power and Local Generation Costs									
	Historical				**Projected**				
Generation and Transmission Costs	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Member Dues	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000
CMPAS Scheduling Charge	$ 12,690	$ 12,690	$ 12,084	$ 14,469	$ 15,257	$ 15,295	$ 15,334	$ 15,372	$ 15,410
CMPAS Contract Administration	$ 11,166	$ 11,166	$ 14,451	$ 12,362	$ 12,000	$ 12,000	$ 12,000	$ 12,000	$ 12,000
NC2 - MWH Energy	$ 155,059	$ 164,046	$ 151,125	$ 158,347	$ 163,800	$ 167,076	$ 170,418	$ 173,826	$ 177,302
MISO Energy Purchases	$ 173,422	$ 117,390	$ 168,021	$ 240,411	$ 239,604	$ 248,615	$ 259,219	$ 269,592	$ 280,361
Gain on Market Sales	$ (14,789)	$ (43,197)	(132,489)	$ (195,293)	$ (150,000)	$ (154,500)	$ (159,135)	$ (163,909)	$ (168,826)
NextEra 5x16 Contract	$ 93,228	$ 93,470			$ -	$ -	$ -	$ -	$ -
5x16 Citi Group	$ -		$ 154,756	$ 154,109	$ 154,278	$ 154,278	$ 154,278	$ 154,278	$ 154,278
WPPI Energy	$ 267,365	$ 267,204	$ 275,713	$ 284,838	$ 286,350	$ 292,077	$ 297,919	$ 303,877	$ 309,954
Wolf Wind Project	$ 3,791	$ 14,698	$ 25,975	$ 17,176	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Mountain Lake Wind Turbine	$ 150,092	$ 164,173	$ 146,298	$ 164,761	$ 81,000	$ 66,000	$ 66,000	$ 66,000	$ 66,000
WAPA Allocation	$ 124,683	$ 136,548	$ 137,870	$ 139,468	$ 162,743	$ 163,241	$ 174,714	$ 174,714	$ 174,714
Transmission	$ 497,822	$ 625,048	$ 584,576	$ 707,639	$ 726,500	$ 750,168	$ 774,608	$ 799,843	$ 825,901
Agency Capacity	$ (10,030)	$ (6,400)	$ (8,450)	$ (165,414)	$ (109,152)	$ (9,792)	$ (15,000)	$ (15,600)	$ (15,600)
Total Purchased Power Costs	**$ 1,482,499**	**$ 1,574,836**	**$ 1,547,930**	**$ 1,550,873**	**$ 1,620,381**	**$ 1,742,459**	**$ 1,788,354**	**$ 1,827,994**	**$ 1,869,495**
Mountain Lake Power Plant Fuel	$ 6,742	$ 5,087	$ 3,541	$ 10,283	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000
Power Plant O&M Costs		$ 13,420	$ 13,750	$ 8,296	$ 8,545	$ 8,802	$ 9,066	$ 9,338	$ 9,618
Total Power Plant Costs	**$ 6,742**	**$ 18,506**	**$ 17,291**	**$ 18,579**	**$ 24,545**	**$ 24,802**	**$ 25,066**	**$ 25,338**	**$ 25,618**
Total Costs - Energy Charge Calc	**$ 1,489,241**	**$ 1,593,343**	**$ 1,565,222**	**$ 1,569,452**	**$ 1,644,926**	**$ 1,767,260**	**$ 1,813,420**	**$ 1,853,331**	**$ 1,895,113**
Percentage Change	-10.2%	7.0%	-1.8%	0.3%	10.5%	7.4%	2.6%	2.2%	2.3%
Energy Purchased / Generated - kWh									
NC2	4,176,212	4,500,812	4,057,600	4,108,000	4,200,000	4,200,000	4,200,000	4,200,000	4,200,000
MISO	8,349,872	7,542,388	6,817,500	7,563,229	7,372,441	7,426,881	7,518,123	7,591,237	7,664,534
NextEra 5x16 Contract	2,032,000	2,056,000	-	-	-	-		-	-
WPPI Energy	4,172,800	4,063,000	4,153,700	4,197,700	4,150,000	4,150,000	4,150,000	4,150,000	4,150,000
5x16 Citigroup	-	-	4,365,492	4,346,100	4,352,000	4,352,000	4,352,000	4,352,000	4,352,000
Mountain Lake Wind Turbine	2,779,477	3,077,283	2,709,234	3,051,121	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
WAPA Allocation	5,882,000	6,121,000	5,897,000	5,978,000	5,985,559	6,003,869	5,985,559	5,985,559	5,985,559
Mountain Lake Power Plant	41,600	15,700	19,489	25,800	40,000	40,000	40,000	40,000	40,000
Total Energy Purchased/Generated	**27,433,961**	**27,376,183**	**28,020,015**	**29,269,950**	**29,100,000**	**29,172,750**	**29,245,682**	**29,318,796**	**29,392,093**
Percentage Change	4.3%	-0.2%	2.4%	4.5%	-0.6%	0.25%	0.25%	0.25%	0.25%
Less: Transmission Loss Adj. (96.5%)	(1,289,396)	(1,286,681)	(1,316,941)	(1,375,688)	(1,018,500)	(1,021,046)	(1,023,599)	(1,026,158)	(1,028,723)
Add: PCA Calc Adj									
Total Sales for PCA Calculation	**26,144,565**	**26,089,502**	**26,703,074**	**27,894,262**	**28,081,500**	**28,151,704**	**28,222,083**	**28,292,638**	**28,363,370**
Costs - Cents / kWh (includes congestion/losses)									
NC2	3.71	3.64	3.72	3.85	3.90	3.98	4.06	4.14	4.22
MISO	2.08	1.56	2.46	3.18	3.25	3.35	3.45	3.55	3.66
NextEra 5x16 Contract	4.59	4.55					-	-	-
WPPI Energy	6.41	6.58	6.64	6.79	6.90	7.04	7.18	7.32	7.47
Citigroup 5x16	-	-	3.54	3.55	3.55	3.55	3.55	3.55	3.55
Mountain Lake Wind	5.40	5.34	5.40	5.40	2.70	2.20	2.20	2.20	2.20
WAPA	2.12	2.23	2.34	2.33	2.72	2.72	2.92	2.92	2.92
Transmission	1.82	2.28	2.09	2.42	2.50	2.58	2.65	2.73	2.81
Local Generation - Fuel only	16.21	32.40	18.17	39.86	40.00	40.00	40.00	40.00	40.00
Power Cost Adjustment Calculation									
Purchased & Local Power Avg. Costs	5.43	5.82	5.59	5.36	5.65	6.06	6.20	6.32	6.45
Cost plus Trans. Loss Adj. (96.5%)	**5.70**	**6.11**	**5.86**	**5.63**	**5.86**	**6.28**	**6.43**	**6.55**	**6.68**
Less: PCA Base Cost	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Annual Average PCA	**(0.80)**	**(0.39)**	**(0.64)**	**(0.87)**	**-**	**-**	**-**	**0.05**	**0.18**

SECTION 3

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SECTION 3 – COST-OF-SERVICE STUDY

The purpose of this study is to determine the cost of providing service to each customer class so that these costs can be compared to actual customer revenues. The cost-of-service analysis has been based on the following factors:

- Test Year revenue requirements and revenues using current rates
- Total system and customer class demand and energy requirements
- Actual and assumed customer service characteristics
- Information obtained from customer records

Test Year revenue requirements were mostly based on projected 2026 expenses. These revenue requirements are classified to cost components and allocated to each customer class based upon service characteristics. These allocated costs are then compared to revenues to determine if current rates recover the appropriate level of revenues from each customer class.

CLASSIFICATION OF COSTS

To allocate costs to customer classifications, costs must first be categorized to components. The seven cost components and the types of costs assigned to each are as follows:

Generation and Transmission 12-Month Coincident Peak Demand Component – The costs of purchasing sufficient power to meet the aggregate demand of all the customers at the time of the 12 monthly system peaks. Coincident peak demand costs do not generally vary with the level of energy used. These costs include capacity-related purchased power and transmission costs along with all of the production expenses with the exception of fuel. These costs also include a portion of distribution, revenue-financed capital expenditures, and reserves for replacements along with the 2021A and 2025A bond series payments. The transmission revenues for the municipally-owned transmission line off-set the transmission cost requirements.

Energy Component – The costs of supplying electricity to meet customer requirements. These costs will vary directly with the usage of electricity. This includes only the energy-related portion of purchased power costs and the fuel costs for the municipally-owned diesel power plant. The costs also include a portion of the revenue-financed capital expenditures and reserves for replacements.

Distribution System 12-Month Coincident Peak Demand Component – The costs of operating and maintaining an electric system that will meet the individual peak demands of each customer class during the system peaks. These costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for

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replacements. The costs also include 50% of the conservation improvement program expenses and revenues (off-set), the 2017A bond series payment, and the transfer to the City of Mountain Lake.

Customer Facilities Component – The costs of providing and maintaining transformers, distribution secondary lines, and customer service drops. Customer facilities costs vary directly with the maximum demand of the customer and the type of facilities the customer requires. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements. The costs also include 50% of the conservation improvement program expenses and revenues (off-set), the 2017A bond series payment, and the transfer to the City of Mountain Lake. The contribution for customer facilities off-sets the revenue requirements.

Customer Service Component – The costs associated with billing, collections, and customer assistance. Customer service costs do not vary greatly with peak demand or energy usage of the customer. The costs include a portion of administrative and general.

Metering Component – The costs of reading meters to determine monthly bills and providing and maintaining customer meters. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements.

Street Lights Component – The costs of operating and maintaining street lighting services. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements.

Indirect Revenues and Expenses

Certain revenues and expenses are not categorized to the seven components above but rather are allocated to these components based on percentage of direct labor spent on each area to the total cost of labor. Allocated in this manner are items such as portion of administrative and general expenses. Other operating revenues and investment income reduce the revenue requirements and are also allocated based on direct labor.

Summary of the Revenue Requirements Classifications

Exhibit 3-A at the end of this section shows the detailed classifications of the test year revenue requirements. A breakdown of the revenue requirements is also shown in the chart on the following page. The projected revenue requirements breakdown shows that 40% of the retail rates recover purchased power, transmission, and production costs, which are not directly controlled at the local level with the exception of the local generation costs. The transfer to the City of Mountain Lake equals 3% of the total costs. The other 57% of the total revenues

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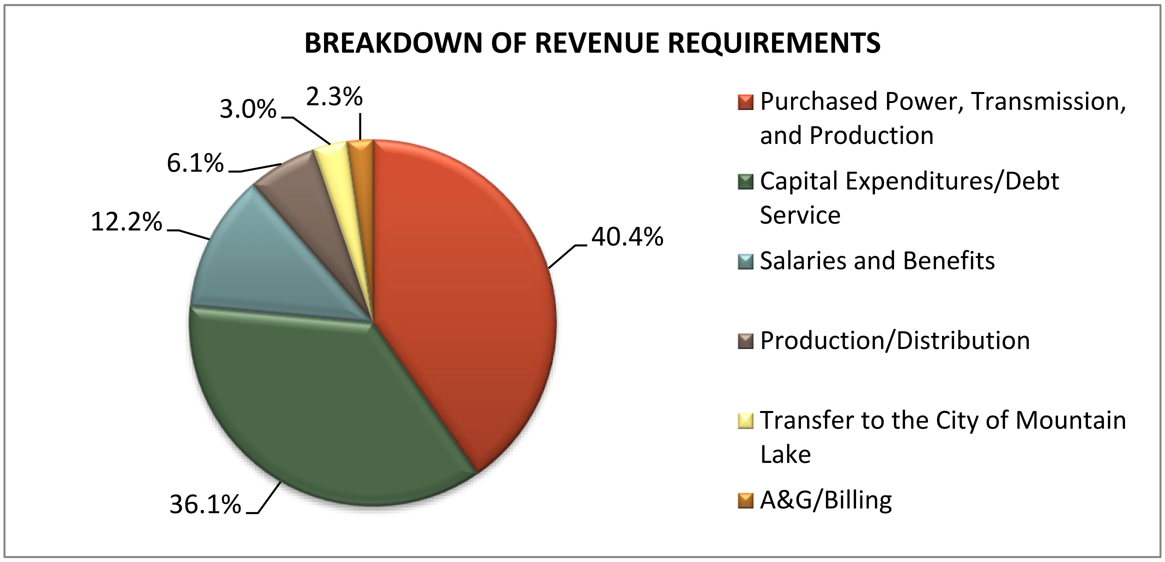
are available to fund local electric utility operations and maintenance costs, capital expenditures, and debt service payments while maintaining sufficient reserves.



ALLOCATION TO CUSTOMER CLASSIFICATIONS

MRES has determined allocation factors for the Test Year based on actual and assumed customer service characteristics. These allocation factors represent historically accepted ratemaking principles and are based on fully distributed, embedded cost allocation procedures. While these principles may still be useful in establishing a baseline cost level upon which to set rates, it is important to note that in a competitive market, some of the allocated costs may not be recovered.

The following summarizes the allocation factors used in the cost-of-service study. See Exhibit 3-B at the end of this section for the development of the factors.

Coincident Peak Demand Allocations

The 12-month coincident peak demand is the estimated class demand at the time of each monthly system peak. This factor is used to allocate the monthly wholesale demand and transmission costs and demand-related distribution costs.

Monthly billing demands for the Large Commercial class were used to estimate the demand allocators for this class. For the other classes, demand allocators were based on the system characteristics of Mountain Lake in relation to the specific classes of service.

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Energy Allocations

Purchased and locally produced energy costs have been allocated based on the annual sales by customer class.

The following three allocations utilize weighted percentages that were developed by analyzing the number of customers in each class and the resources used to serve each class. The weighting factors were based on the experience of other utilities and Mountain Lake staff observations.

Customer Facilities Allocations

Customer facilities allocations are based on the complexity and size of the transformers, distribution secondary lines, and service lines used to serve the various customer classes.

Customer Service Allocations

Customer service allocations are based on the amount of labor and materials for customer billing and collection.

Metering Allocations

Metering allocations are based on the time spent reading and maintaining the meters of the various customer classes. These costs vary between classes that have and do not have a demand meter installed. The costs also vary between in-town customers and rural customers.

Based upon the cost classifications and allocation methods described above, MRES has estimated the cost to serve each customer class during the Test Year. A summary of the results is shown on the following page, and the detailed results are shown on Exhibit 3-C at the end of this section.

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SUMMARY OF RESULTS

The cost-of-service study indicated that most classes are close to the cost of service but current rates will not recover future expenses. Lastly, the study also indicated the municipal class should see a much larger increase. Historically, the municipal class was billed a discounted rate. Mountain Lake has continued to increase this rate to bring it closer to the cost of service since the 2015 rate study.

The percentages in the far right column below indicate the changes that would be necessary in each class to set rates in line with the costs of service and implement the proposed cumulative rate increases during the study period. In addition to the cost of service results, other factors are also considered when determining proposed rate plan.

Cost of Service Results by Class					
Customer Classification	**Cost per kWh**	**Revenue per kWh**	**Cost Less Revenue**		**Cost of Service Results**
Residential	$0.179	$0.140	$0.039		**27.7%**
Commercial	$0.160	$0.127	$0.033		**26.6%**
Large Commercial	$0.125	$0.101	$0.024		**24.6%**
Rural	$0.176	$0.140	$0.036		**25.8%**
Municipal	$0.155	$0.099	$0.056		**57.6%**
Street Lights	$0.107	$0.093	$0.014		**15.9%**
Total	**$0.142**	**$0.113**	**$0.029**		**26.0%**

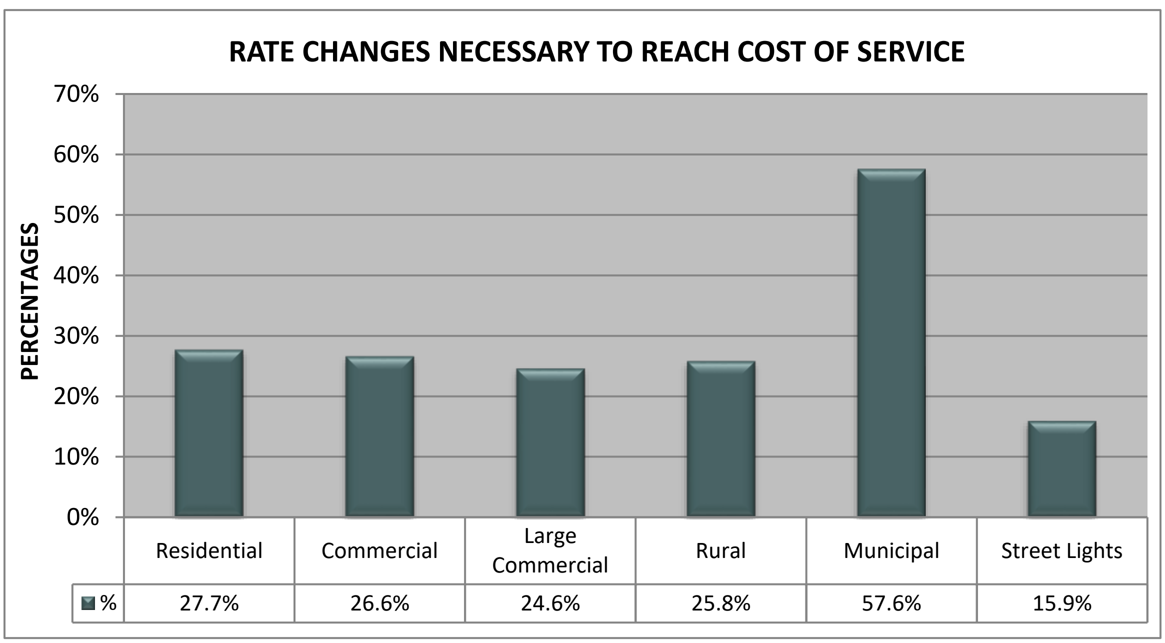

Exhibit 3-A

Mountain Lake Municipal Utilities
Classification of Test Year Requirements

Revenue Requirements	Total	Generation/ Transmission 12 CP Demand	Energy	Distribution System 12 CP Demand	Customer Facilities (CF)	Customer Service (CS)	Metering (MR)	Street Lighting (SL)	Basis for Classification
Purchased Power & Transmission									
Nebraska City 2 Purchases	$ 170,418	59,646	110,771						35% 12CP, 65% Energy
MISO Market Purchases	99,079	-	99,079						100% Energy
Citi Group Energy: 5 X 16 Contract	154,278	23,142	131,137						15% 12CP, 85% Energy
WPPI Purchases	297,919	59,584	238,335						20% 12CP, 80% Energy
Wolf Wind	20,000		20,000						100% Energy
WAPA Allocation	174,714	75,651	99,063						43% 12CP, 57% Energy
ITC Midwest Transmission	773,834	773,834							100% 12CP
CMPAS Agency and Scheduling Fees	30,318	(15,000)	45,318						Per Purchased Power Requirements
Mountain Lake Wind Tower Maintenance	63,654	6,365	57,289						10% 12CP, 90% Energy
Land Rent for Wind Turbine	4,000	400	3,600						10% 12CP, 90% Energy
Moutain Lake Transmission Line Revenue (B)	(175,000)	(175,000)							100% 12CP
Operating Expenses (A)									
Production									
Supplies, repairs, maintenance	89,615	89,615							100% 12CP
Fuel Oil/Diesel	21,218		21,218						100% Energy
Distribution									
Salaries and Employee Benefits	353,075	31,509		146,998	146,998		19,693	7,877	Per distribution labor requirements
Meetings, Meals and Travel	530			265	265				50% CP, 50% CF
Telephone	764			382	382				50% CP, 50% CF
Street Lighting and Signal	2,122							2,122	100% SL
Repairs and Maintenance: Misc	21,218			7,609	7,609			6,000	Per repair and maintenance expense requirements
Repair and Maintenance: Meters	16,974						16,974		100% MR
Maint of Ditch Witch	6,365			3,183	3,183				50% 12CP, 50% CF
Substation/Line Maint.	63,654			31,827	31,827				50% 12CP, 50% CF
Miscellaneous	24,401			12,201	12,201				50% 12CP, 50% CF
Wells and Lift Station Power	2,122			1,061	1,061				50% 12CP, 50% CF
Conservation Improv. Program									
CIP Program Expenses	34,218			17,109	17,109				50% 12CP, 50% CF
CIP 1.5% Surcharge Revenues	(45,386)			(22,693)	(22,693)				50% 12CP, 50% CF
Administrative and General									
A&G Salaries and Benefits	131,901	4,134		19,285	19,285	85,581	2,584	1,033	Direct and indirect rev. and exp. allocation factors (D)
Utility Commission Salaries	1,337	98		456	456	242	61	24	Indirect revenue and expense allocation factors (C)
Motor Fuels	3,713			1,107	1,107		1,000	500	Per fuels expense requirement
Postage	5,305					5,305			100% CS
Professional Services	530	39		181	181	96	24	10	Indirect revenue and expense allocation factors (C)
General Liability Insurance	68,959	5,038		23,504	23,504	12,504	3,149	1,260	Indirect revenue and expense allocation factors (C)
Capital Improvement: Other Projects	25,462			12,731	12,731				50% 12 CP, 50% CF
Capital Outlay: Equipment	10,300			5,150	5,150				50% 12 CP, 50% CF
Office and Computer Supplies, Utilities	51,455	3,759		17,538	17,538	9,330	2,350	940	Indirect revenue and expense allocation factors (C)

Exhibit 3-A

Mountain Lake Municipal Utilities
Classification of Test Year Requirements

Revenue Requirements	Total	Generation/ Transmission 12 CP Demand	Energy	Distribution System 12 CP Demand	Customer Facilities (CF)	Customer Service (CS)	Metering (MR)	Street Lighting (SL)	Basis for Classification
Revenue-Financed Capital Expenditures									
Local Generation	84,694	34,347	50,348						Per depreciation schedule
Distribution - Demand-Related Facilities	33,404			33,404					Per depreciation schedule
Distribution - Customer Facilities	32,631				32,631				Per depreciation schedule
Meter Reading	1,419						1,419		Per depreciation schedule
Street Lighting	7,852							7,852	Per depreciation schedule
Contributions for Customer Facilities (B)	(3,200)				(3,200)				100% CF
Other Operating Revenues (B)	(11,000)	(804)		(3,749)	(3,749)	(1,995)	(502)	(201)	Indirect revenue and expense allocation factors (C)
Investment Income (B)	(50,000)	(3,653)		(17,042)	(17,042)	(9,066)	(2,283)	(913)	Indirect revenue and expense allocation factors (C)
2017A Bond Principal and Interest	289,383			144,692	144,692				50% 12 CP, 50% CF
2021A Bond Principal and Interest: Generation	212,600	212,600							100% 12 CP
2025A Bond Principal and Interest: Generation	780,617	780,617							100% 12 CP
Transfer to the City of Mountain Lake	120,000			60,000	60,000				50% 12 CP, 50% CF
Contributions to Reserves for Replacements	5,000	1,073	1,573	1,044	1,020	-	44	245	Per depreciation schedule
Revenue Requirements	**$ 4,006,465**	**$ 1,966,994**	**$ 877,730**	**$ 496,240**	**$ 492,242**	**$ 101,997**	**$ 44,512**	**$ 26,750**	

(A) Expenses are adjusted to level of typical year.
(B) These amounts offset revenue requirements.
(C) Indirect revenue and expenses are allocated based on breakdown of direct labor expenses.
(D) A portion of this expense was classified directly to one of the above allocators. The remaining portion was allocated based on the indirect expense allocation factors described in (C).

Mountain Lake Municipal Utilities
Allocation Factors

Exhibit 3-B

Allocation Factors	Total	Residential	Commercial/ City Facilities	Large Commercial	Rural	Street Lighting
Demand Allocation Factors						
12-Month Coincident Peak (kW)	58,114	19,016	4,469	33,570	907	153
Percentage - CP	100%	32.7%	7.7%	57.8%	1.6%	0.3%
Energy Allocation Factors						
Annual Energy Requirements (kWh)	29,225,236	7,833,388	1,723,518	18,701,989	381,858	584,483
Percentage - E	100%	26.8%	5.9%	64.0%	1.3%	2.0%
Customer Facilities Allocation Factors						
Average number of customers	1,394	837	54	43	34	426
Weighting factor		1.0	1.4	31.0	1.2	0.1
Weighted number of customers	2,329	837	76	1,333	41	43
Percentage - CF	100%	35.9%	3.2%	57.2%	1.8%	1.8%
Customer Service Allocation Factors						
Average number of customers	969	837	54	43	34	1
Weighting factor		1.0	1.0	2.0	1.0	1.0
Weighted number of customers	1,012	837	54	86	34	1
Percentage - CS	100%	82.7%	5.3%	8.5%	3.4%	0.1%
Metering Service Allocation Factors						
Average number of customers	969	837	54	43	34	1
Weighting factor		1.0	1.0	2.0	1.5	1.0
Weighted number of customers	1,029	837	54	86	51	1
Percentage - MR	100%	81.3%	5.2%	8.4%	5.0%	0.1%

Exhibit 3-C

Mountain Lake Municipal Utilities
Allocation of Revenue Requirements

Classification	Total	Residential	Commercial	Large Commercial	Rural	City Facilities	Street Lighting
Generation & Transmission 12 CP Demand	$ 1,966,994	$ 643,633	$ 118,437	$ 1,136,256	$ 30,688	32,809	$ 5,172
Energy	877,730	235,262	40,534	561,682	11,468	11,229	17,554
Distribution 12 CP Demand	496,240	162,378	29,880	286,658	7,742	8,277	1,305
Customer Facilities	492,242	176,903	13,391	281,734	8,623	2,587	9,004
Customer Service	101,997	84,359	4,636	8,668	3,427	806	101
Metering	44,512	36,207	1,990	3,720	2,206	346	43
Street Lighting (Direct Allocation)	26,750	-	-	-	-	-	26,750
Revenue Requirements	**$ 4,006,465**	**$ 1,338,742**	**$ 208,869**	**$ 2,278,718**	**$ 64,154**	**$ 56,054**	**$ 59,928**
Class Revenues	$ 3,179,853	$ 1,047,968	$ 165,006	$ 1,828,613	$ 50,998	$ 35,570	$ 51,698
Difference (Rev. Req. Less Revenues)	$ 826,613	$ 290,775	$ 43,863	$ 450,105	$ 13,156	$ 20,484	$ 8,230
Cost of Service Adjustment Percentage	**26.0%**	**27.7%**	**26.6%**	**24.6%**	**25.8%**	**57.6%**	**15.9%**

SECTION 4

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SECTION 4 – PROPOSED RATES

Several factors were considered in determining the proposed rates:

- Projected net income and cash reserves (Section 2)
- Costs to serve each customer class (Section 3)
- Rate comparisons (Section 5)
- Mountain Lake policies and objectives

RATE DESIGN

The analysis outlined in Section 2 indicated that under current rates, cash reserves would decrease from nearly $3.3 million in 2022 to $1.4 million in 2027. The drastic decrease in reserves is mostly due to the additional debt service associated with the generation project. **Based on the analysis outlined in this report, the rate study recommends rates that would result in 8% overall increases in 2024, 2025 and 2026. Individual customers may see higher or lower increases than the overall percentage.** The proposed rates are discussed next, and the rates are shown on page 4-3. Further adjustments may be necessary during the study period if operating costs, retail energy sales, or the financial needs of the utility change drastically.

Over the last several years Mountain Lake has made progressive cost of service adjustments to better align how costs are recovered and enhance equity between rate classes. The cost of service results shown on page 3-5 show that minor adjustments could be made between classes to ensure cost-based rates. The proposed rate designs include adjustments to the rate components (availability charge, energy rate, and demand rate, where applicable) within each class that better reflect the cost of providing service to that class. The proposed rate designs should allow Mountain Lake to better recover its costs in a more equitable way from its customers while maintaining the financial health of the utility.

Proposed Electric Rate Recommendations

1. Increase the monthly customer charges for all customers. The customer charge, which does not include any kWh usage, recovers the costs of serving customers in areas such as meter installation and maintenance and customer billing, along with a portion of facilities costs.

   Higher customer charges also help to prepare the utility for the possibility of customers adding distributed energy resources in the future. Many utilities have been steadily increasing their customer charges in recent years. Based on a review of residential customer charges for approximately 110 area municipal utilities, the average charge is

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over $14.50 per month in 2023, and the average is expected to steadily increase in the future.

2. Maintain the PCA base factor of $0.0650 per kWh and continue the current calculation to determine the monthly PCA. The PCA allows the utility to recover varying purchased power supply, transmission, and local generation costs from its customers between formal rate adjustments. The calculation to determine the monthly PCA is as follows:

    - Purchased Power Costs + Local Production Costs = Total Power Costs
    - Total Energy Purchased and Generated times 96.5% Loss Factor = Approximate Retail kWh Sales
    - Total Power Costs / Total Retail kWh Sales = Power Costs per kWh Sold
    - Power Costs per kWh Sold less 6.5 cent PCA base = Adjustment for the next customer billing month

    Over the last several years Mountain Lake's PCA has been negative indicating that purchased power and transmission costs have been lower than the established PCA base. The negative credits have been retained by Mountain Lake to offset future costs. Purchased Power and transmission costs are expected to increase during the study period. The PCA is projected to become positive in 2026 and 2027 and Mountain Lake would begin billing customers the applicable PCA at that time.

3. Maintain the qualifications for the Large Commercial class which includes any non-residential customer with a peak demand of 20 kW or more in three or more months out of the previous 12 months. The customers that qualify for the Large Commercial class would remain in the class for a minimum of 12 months. The cost of service study indicated that the demand rate should be around $37 per kW and the energy rate about $0.032 per kWh. The proposed rates will continue to shift this class in the direction indicated by the cost-of-service analysis.

4. Increase the energy rate for the City Facilities and Street Lighting class. The city facilities, including the water and wastewater treatment plants, are currently paying a discounted energy rate compared to the Commercial and Large Commercial classes. Most area utilities have eliminated discounts for city and other utility department usage so that all customers pay the same rate for similar usage characteristics. The City rates have been steadily increased each year since 2016, and this transition would continue with the proposed 2024 through 2026 rates.

    Street lighting usage will continue to be billed in the City Facilities class. The electric utility has recently completed the conversion of high pressure sodium lights (HPS) to light emitting diode (LED) lamps. Higher installation and fixture costs coupled with lower electric usage increases the cost per kWh to serve the street lights.

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5. Maintain the Conservation Improvement Plan surcharge of 1.5% of the total bill to provide funding for energy efficiency and other conservation programs offered by Mountain Lake.

Current and Proposed Rate Increases by Year				
Customer Class	2024 Percent Increase	2025 Percent Increase	2026 Percent Increase	2024-2026 % Change
Overall Revenue Change	**8.0%**	**8.0%**	**8.0%**	
Residential	8.0%	8.1%	8.1%	26.3%
Rural	7.2%	8.3%	8.3%	25.7%
Commercial	7.5%	8.0%	8.0%	25.4%
Large Commercial (Over 20 kW)	7.9%	7.8%	7.7%	25.2%
City Facilities & Street Lighting	11.7%	12.0%	11.6%	39.6%

Current and Proposed Rates						
Customer Class	Rate Components	Current Rates	2024 Proposed Rates	2025 Proposed Rates	2026 Proposed Rates	2024-2026 % Change
Overall Revenue Change			**8.0%**	**8.0%**	**8.0%**	
Power Cost Adjustment	Adjustment Base Factor Average Adjustment	$0.0650 0.0000	$0.0650 0.0000	$0.0650 0.0000	$0.0650 0.0005	
Residential	Customer Charge Energy Charge – per kWh	$14.57 $0.1176	$16.50 $0.1260	$18.00 $0.1360	$19.50 $0.1470	26.3%
Rural	Customer Charge Energy Charge – per kWh	$17.68 $0.1176	$19.00 $0.1260	$21.00 $0.1360	$23.00 $0.1470	25.7%
Commercial	Customer Charge Energy Charge – per kWh	$24.97 $0.1100	$26.00 $0.1230	$28.00 $0.1330	$30.00 $0.1440	25.4%
Large Commercial (Over 20 kW)	Customer Charge Demand Charge – per kW Energy Charge – per kWh	$57.22 $14.57 $0.0604	$58.00 $18.25 $0.0590	$60.00 $21.95 $0.0580	$62.00 $25.90 $0.0570	25.2%
City Facilities & Street Lighting	Customer Charge Energy Charge – per kWh	$24.97 $0.0895	$26.00 $0.1000	$28.00 $0.1120	$30.00 $0.1250	39.6%
Conservation Improvement Plan	Surcharge – % of Electric Bill	1.5%	1.5%	1.5%	1.5%	

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CUSTOMER BILLS AND AVERAGE REVENUE PER KWH GRAPHS

Exhibits 4-B through 4-D at the end of this section contain graphs of customer bills for the Residential and Commercial classes, and average revenue per kWh for the Large Commercial class. The averages on Exhibit 4-D can be used to calculate the bills by knowing the load factor of the Large Commercial customers. The rates per kWh for this exhibit are calculated using a monthly demand of 20 kW and load factors ranging from 20% to 75%.

Finally, exhibit 4-E shows a cost per kWh comparison between the Commercial and Large Commercial classes with load factors ranging from 20% to 75% based on a customer demand of 20 kW. This shows that most customers with a load factor above 44% would pay a lower cost per kWh in the Large Commercial class.

All of these graphs are calculated under current and 2024 through 2026 proposed rates including the 1.5% CIP adder.

RETAIL RATE RECOMMENDATION RESULTS

As a result of the proposed 2024 rates, a typical Residential customer using 800 kWh per month would see an increase of $8.78 per month, or 8.0%. Meanwhile, a Residential heating customer using 1,600 kWh would see an increase of $15.60 per month, or 7.6%.

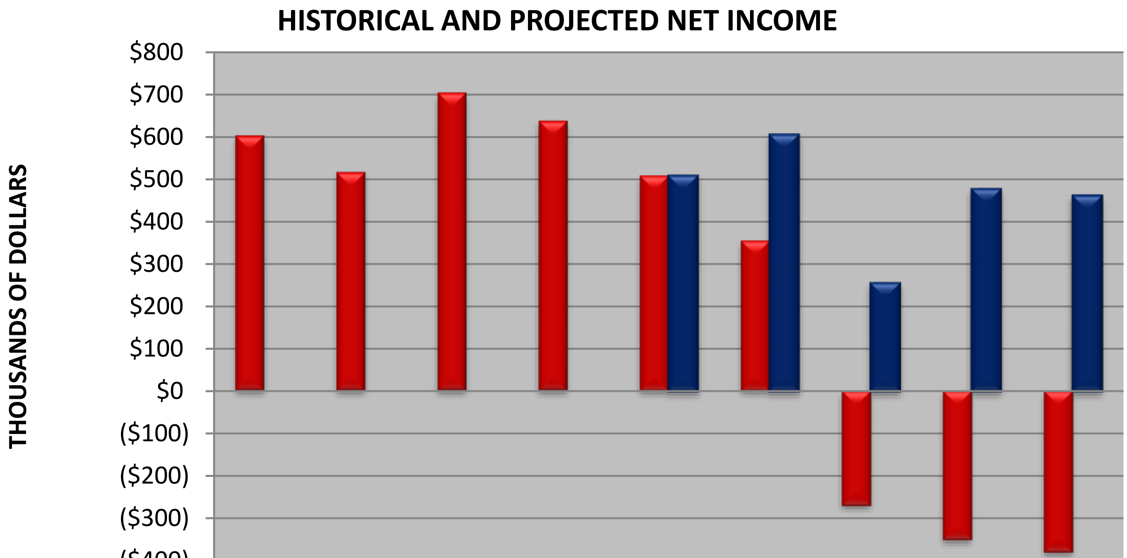
Most Commercial customers would see an increase between 6.6% to 8.2%. Finally, Large Commercial customers would see increases ranging from 6% to 12% based on their monthly load factor. Customers with higher load factors will typically see a lower decrease.

City facilities and Street Lighting would see an average increase of 11.7% in 2024 due to increasing the energy rate closer to the Commercial class rate.

HISTORICAL AND PROJECTED OPERATING RESULTS

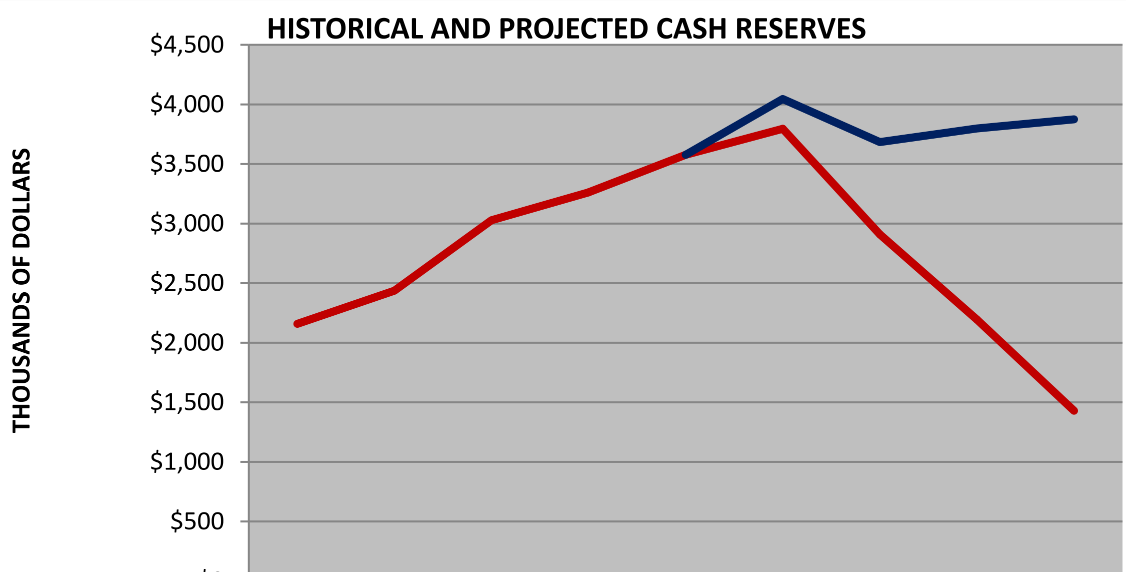
Based on the assumptions described in Section 2, MRES has projected the net income and cash reserves as shown on the graphs on the following page and in Exhibit 4-A. Depending on any changes to the key assumptions, other rate adjustments may be necessary. Under proposed rates, net income is projected at $605,000 in 2024 before dropping off to $461,000 in 2027.

HISTORICAL AND PROJECTED OPERATING RESULTS (continued)



	2019	2020	2021	2022	2023	2024	2025	2026	2027
Current Rates	$603	$517	$704	$637	$508	$355	$(271)	$(352)	$(381)
Proposed Rates					$508	$605	$255	$476	$461

The next graph shows that under proposed rates, cash reserves are projected to increase to around $4 million in 2024, before decreasing slightly in 2025. Cash reserves are then projected to increase to around $3.9 million by 2027.



	2019	2020	2021	2022	2023	2024	2025	2026	2027
Current Rates	$2,158	$2,436	$3,028	$3,262	$3,577	$3,795	$2,909	$2,194	$1,429
Proposed Rates					$3,577	$4,045	$3,684	$3,798	$3,874

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Debt Service Coverage

Debt service coverage (DSC) is the ratio between the current year's available cash for debt service and the debt service obligations. The DSC ratio is a financial benchmark to ensure Mountain Lake has adequate cash flow to meet its current and future debt service payments. Mountain Lake's DSC is projected to decrease from about 2.2 in 2023 to less than 0.5 coverage by 2027. The recommended minimum coverage is typically 1.1 but can be higher if required by the bond covenants. The decrease in DSC is because of the additional debt issuance in 2025. Under proposed rates, the DSC would drop to 1.03 in 2025 before increasing to around 1.2 in 2026 and 2027.

Importance of Cash Reserves

Maintaining adequate reserve levels is important for several reasons. Reserves would provide for unanticipated expenses or contingencies that may arise. Reserves also provide the utility with greater flexibility when determining whether to pay for capital expenditures through revenues and reserves, or debt financing, which has additional servicing costs associated with it. An adequate reserve level would also provide for short-term rate stabilization if a large commercial or industrial customer closed or drastically changed their operations, which would result in a smaller customer base from which to recover costs. Cash reserves are also a significant factor used by bond rating agencies for evaluating utilities such as Mountain Lake.

In a study of 89 area municipal electric utility financial statements, MRES found that the median level of unrestricted cash reserves as a percentage of operating revenues was 67% for these utilities. Around one third of those utilities have cash reserves exceeding 80% of operating revenues. Under proposed rates, Mountain Lake's cash reserves are projected to average around 104% during the study period.

BENEFITS OF A PUBLIC POWER SYSTEM

The City of Mountain Lake, its residents, and businesses receive many benefits by being served by a public power system. One of the many benefits is that the Mountain Lake Utility Commission has local control of the electric rates and the utility's policies and objectives. Another benefit is the operating transfer to the City of Mountain Lake to help support city services that may otherwise not be funded. Other advantages of having a public power system in Mountain Lake are local customer service and the ability to issue tax-exempt financing when necessary for improvements, which is typically at a lower cost of financing. Lastly, shared billing services and equipment with other city utilities helps keep the total operating costs lower for all of these services.

Exhibit 4-A

Mountain Lake Public Utilities

Electric Utility Operating Results

(Proposed Rates: 8% Overall Increase in 2024, 2025 and 2026)

	Projected				
	2023	2024	2025	2026	2027
Total System Retail kWh Sales	28,115,942	28,186,232	28,256,697	28,327,339	28,398,158
kWh % Change	-0.3%	0.3%	0.2%	0.2%	0.2%
OPERATING REVENUES					
Metered Electric Sales	$ 3,121,258	$ 3,379,875	$ 3,659,272	$ 3,976,136	$ 4,023,290
Other Operating Revenues	60,319	57,951	58,064	58,397	59,074
Total Operating Revenues	3,181,577	3,437,826	3,717,335	4,034,532	4,082,363
OPERATING EXPENSES					
Purchased Power & Transmission	1,539,381	1,676,459	1,722,354	1,761,994	1,803,495
Production	100,700	103,721	106,833	110,038	113,339
Distribution	523,027	479,618	494,007	508,827	524,092
Administrative & General	294,590	302,617	305,886	314,553	323,479
Depreciation Expense	359,751	365,686	371,689	376,084	380,715
Total Operating Expense	2,817,449	2,928,101	3,000,768	3,071,494	3,145,120
NET OPERATING INCOME	364,128	509,725	716,567	963,038	937,243
NON-OPERATING REVENUES (EXPENSES)					
Interest Income	201,757	160,790	87,407	55,267	56,965
Refunds and Reimbursements	3,200	3,200	3,200	3,200	3,200
CAPX Transmission Revenues	198,000	186,120	174,953	164,456	154,588
Interest Expense	(138,995)	(135,020)	(607,433)	(589,474)	(570,728)
Total Non-Operating Revenue (Expense)	263,962	215,090	(341,873)	(366,552)	(355,975)
TRANSFER TO THE GENERAL FUND	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)
NET INCOME (LOSS)	**$ 508,090**	**$ 604,816**	**$ 254,694**	**$ 476,486**	**$ 461,269**
Net Income (Loss) as a Percent of Oper. Revenue	16.0%	17.6%	6.9%	11.8%	11.3%
Debt Service Coverage	218%	240%	103%	120%	118%

Electric Utility Cash Reserves

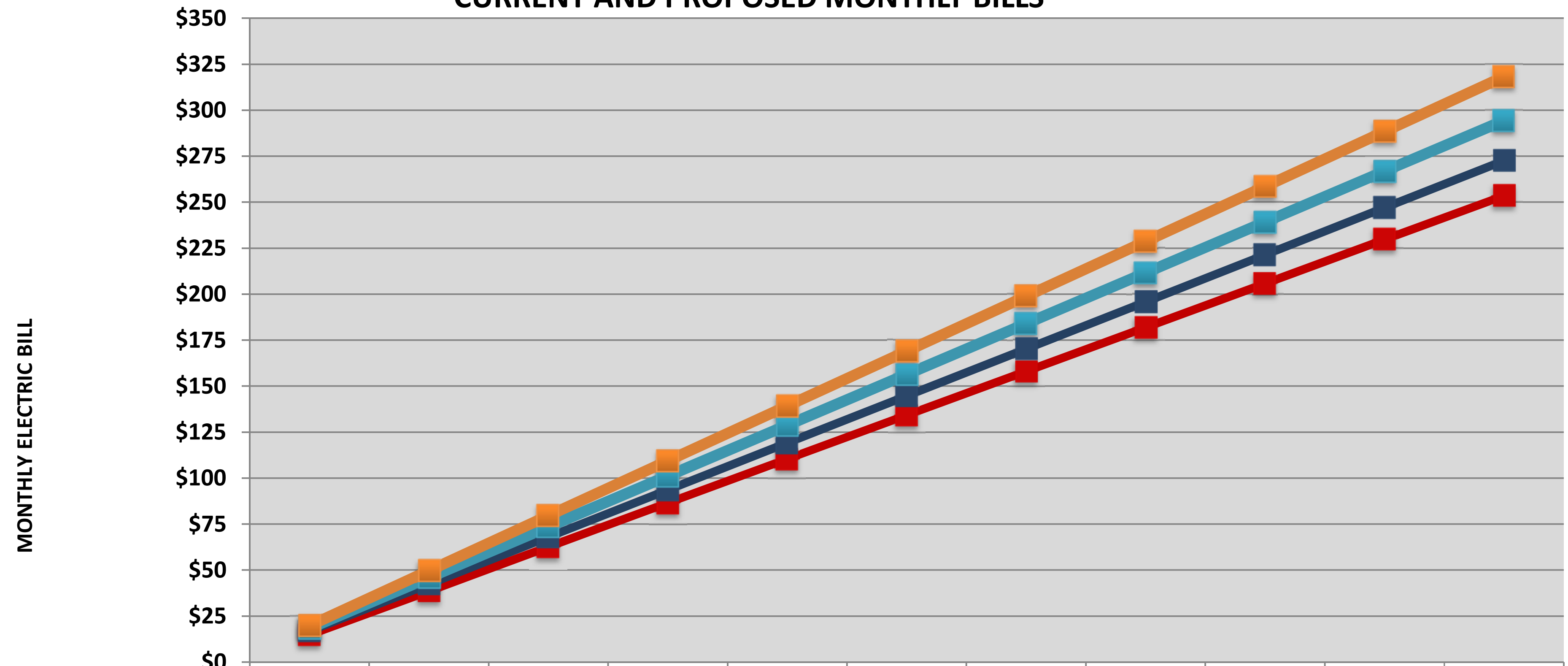
	Estimated				
	2023	2024	2025	2026	2027
NET INCOME (LOSS)	$ 508,090	$ 604,816	$ 254,694	$ 476,486	$ 461,269
LESS: Revenue-Financed Capital Expenditures	(228,333)	(178,053)	(180,095)	(131,834)	(138,939)
LESS: Generation Project			(14,000,000)		
ADD: 2025 Bond Revenues			12,000,000		
ADD: 2021A Revenues			1,782,253		
LESS: Bond Principal Payment 2025A	-	-	(213,961)	(222,520)	(231,420)
LESS: Bond Principal Payment 2021A	(180,000)	(180,000)	(185,000)	(190,000)	(195,000)
LESS: Bond Principal Payment 2017A	(15,000)	(145,000)	(190,000)	(195,000)	(200,000)
LESS: Bond Principal Payment 2007B	(128,750)	-	-	-	-
ADD: Depreciation Expense	359,751	365,686	371,689	376,084	380,715
ADDITION (REDUCTION) IN RESERVES	**$ 315,758**	**$ 467,448**	**$ (360,419)**	**$ 113,216**	**$ 76,624**
Beginning of Year Unrestricted Reserves	$ 3,261,672	$ 3,577,430	$ 4,044,879	$ 3,684,459	$ 3,797,675
Addition (Reduction) in Reserves	315,758	467,448	(360,419)	113,216	76,624
Addition to Restricted Fund					
End of Year Unrestricted Reserves	**$ 3,577,430**	**$ 4,044,879**	**$ 3,684,459**	**$ 3,797,675**	**$ 3,874,299**
Reserves as Percentage of Operating Revenues	**112%**	**118%**	**99%**	**94%**	**95%**

MONTHLY BILLS

Exhibit 4-B

Residential Monthly Bills

CURRENT AND PROPOSED MONTHLY BILLS

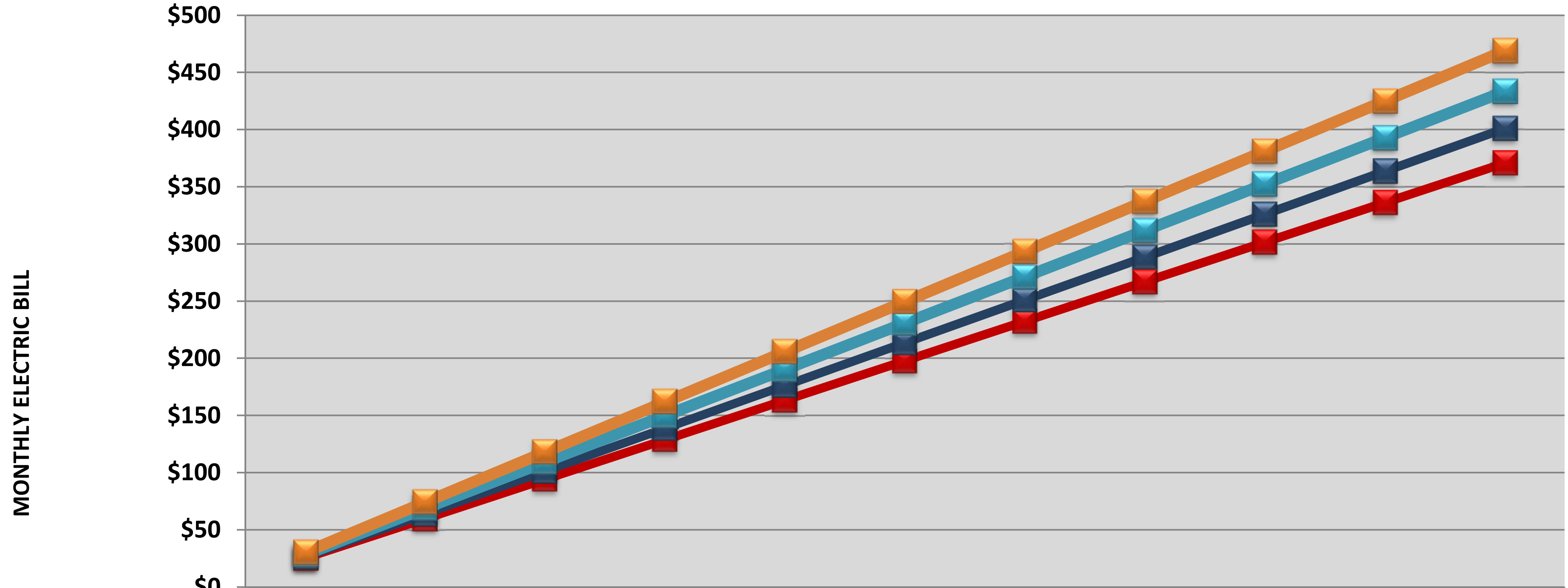


	-	200	400	600	800	1,000	1,200	1,400	1,600	1,800	2,000
Current Rates	$14.79	$38.66	$62.53	$86.41	$110.28	$134.15	$158.03	$181.90	$205.77	$229.64	$253.52
2024 Proposed Rates	$16.75	$42.33	$67.90	$93.48	$119.06	$144.64	$170.22	$195.79	$221.37	$246.95	$272.53
% Increase	13.2%	9.5%	8.6%	8.2%	8.0%	7.8%	7.7%	7.6%	7.6%	7.5%	7.5%
$ Increase	$1.96	$3.66	$5.37	$7.07	$8.78	$10.48	$12.19	$13.90	$15.60	$17.31	$19.01
2025 Proposed Rates	$18.27	$45.88	$73.49	$101.09	$128.70	$156.31	$183.92	$211.53	$239.13	$266.74	$294.35
2026 Proposed Rates	$19.79	$49.63	$79.47	$109.32	$139.16	$169.00	$198.84	$228.68	$258.52	$288.36	$318.20

KWH

Commercial Monthly Bills

CURRENT AND PROPOSED MONTHLY BILLS



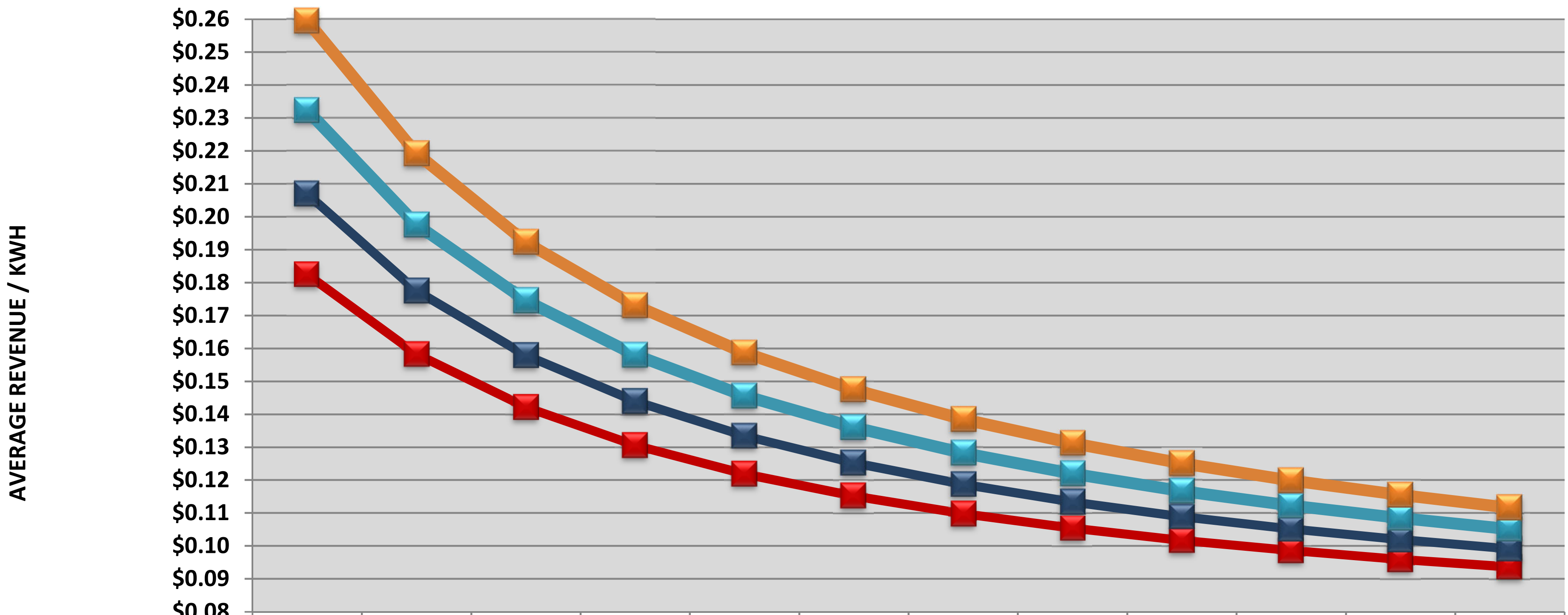
	-	300	600	900	1,200	1,500	1,800	2,100	2,400	2,700	3,000
Current Rates	$25.34	$59.87	$94.41	$128.94	$163.47	$198.00	$232.53	$267.06	$301.59	$336.12	$370.65
2024 Proposed Rates	$26.39	$63.84	$101.30	$138.75	$176.20	$213.66	$251.11	$288.56	$326.02	$363.47	$400.93
% Change	4.1%	6.6%	7.3%	7.6%	7.8%	7.9%	8.0%	8.1%	8.1%	8.1%	8.2%
$ Change	$1.05	$3.97	$6.89	$9.82	$12.74	$15.66	$18.58	$21.51	$24.43	$27.35	$30.28
2025 Proposed Rates	$28.42	$68.92	$109.42	$149.92	$190.41	$230.91	$271.41	$311.91	$352.41	$392.91	$433.41
2026 Proposed Rates	$30.45	$74.30	$118.15	$161.99	$205.84	$249.69	$293.54	$337.39	$381.23	$425.08	$468.93

KWH

Exhibit 4-D

Large Commercial Monthly Bill: Average Cost per kWh at 20 kW

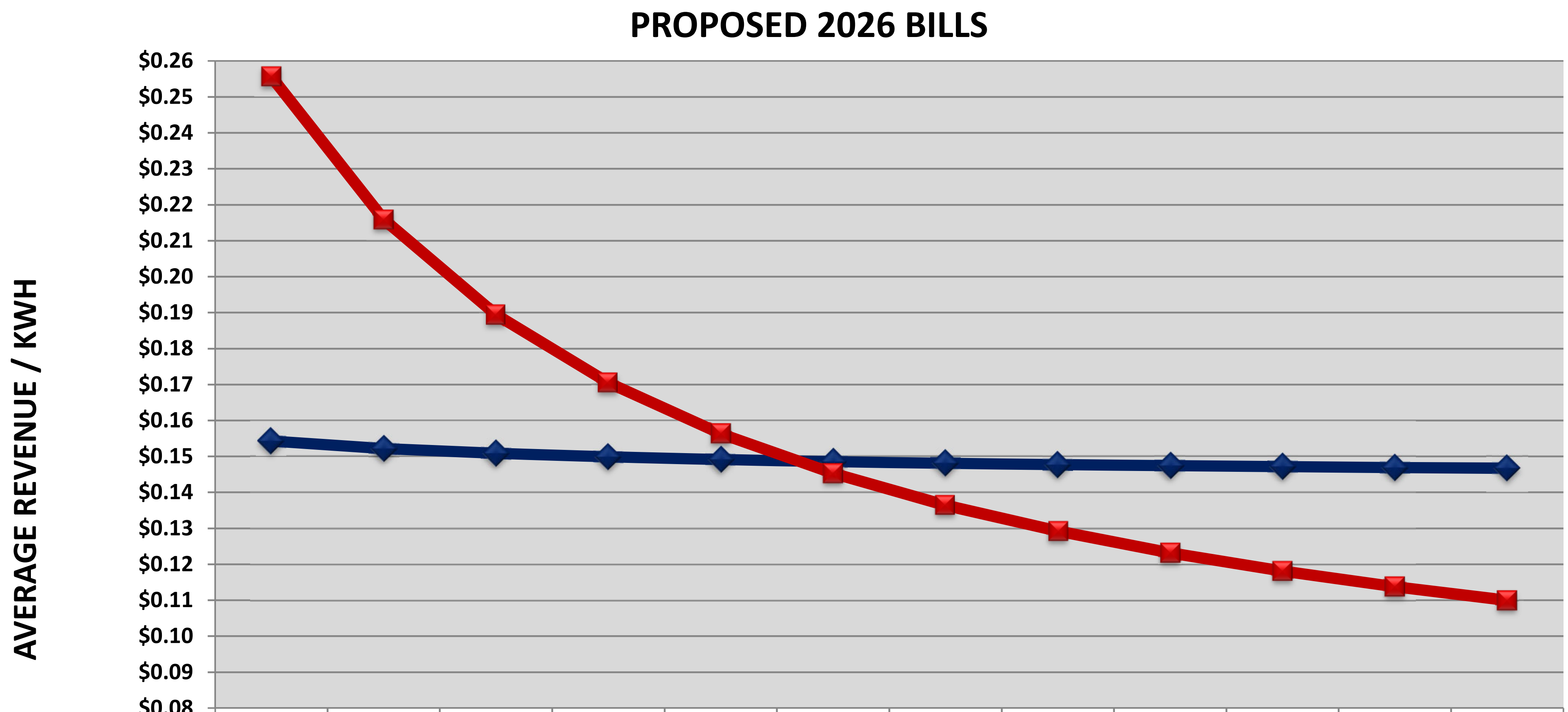
CURRENT AND PROPOSED BILLS



	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Current Rates	$0.182	$0.158	$0.142	$0.131	$0.122	$0.115	$0.110	$0.105	$0.102	$0.099	$0.096	$0.094
2024 Proposed Rates	$0.207	$0.178	$0.158	$0.144	$0.133	$0.125	$0.119	$0.113	$0.109	$0.105	$0.102	$0.099
% Change	13.4%	12.2%	11.1%	10.2%	9.4%	8.7%	8.1%	7.6%	7.1%	6.6%	6.2%	5.8%
$ / kWh Change	$0.024	$0.019	$0.016	$0.013	$0.012	$0.010	$0.009	$0.008	$0.007	$0.007	$0.006	$0.005
2025 Proposed Rates	$0.232	$0.198	$0.175	$0.158	$0.146	$0.136	$0.128	$0.122	$0.117	$0.112	$0.108	$0.105
2026 Proposed Rates	$0.259	$0.219	$0.192	$0.173	$0.159	$0.147	$0.138	$0.131	$0.125	$0.120	$0.115	$0.112

LOAD FACTOR

Commercial vs. Large Commercial Monthly Bill: Average Cost per kWh at 20 kW



	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Commercial	0.154	0.152	0.151	0.150	0.149	0.149	0.148	0.148	0.147	0.147	0.147	0.147
Large Commercial	0.256	0.216	0.189	0.171	0.156	0.145	0.136	0.129	0.123	0.118	0.114	0.110
% Difference	65.7%	41.8%	25.6%	13.8%	4.8%	-2.2%	-7.9%	-12.5%	-16.4%	-19.7%	-22.6%	-25.1%

LOAD FACTOR

SECTION 5

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SECTION 5 – RATE COMPARISONS WITH OTHER ELECTRIC UTILITIES

Historically, in a non-competitive environment where utility franchise territories were protected, a utility could reasonably set rates on a cost-of-service plus margin basis, or the utility could diverge from the cost study and set rates according to local policy objectives. However, some portions of the country have now been opened to retail competition. Although retail competition may be many years away in this area, it is still important to understand the competitive position of the utility for other reasons such as economic development. The information in this section is also useful in examining the various methods used by the utilities to recover costs from the different classes.

DIFFERENCE OF RATES AMONG MEMBER UTILITIES

Electric rates vary from utility to utility due to several factors. Some of the differences may be explained by the following factors:

- The percentage of power purchased from the WAPA in comparison to the power purchased from other suppliers
- The cost of transmission services
- The equitability of the rates across the various customer classes
- The blend of retail customers, such as the percentage of Commercial and Large Commercial energy sales
- The percentage of revenues that is transferred to other non-electric funds
- The amount of expenses that may be subsidized by other utilities, for example, the electric utility paying for other city utilities' labor and/or other expenses
- The amount of funds spent in recent years on capital improvement projects, which correlates to the condition and reliability of the distribution system
- The amount of annual debt service, along with the covenants and restricted reserves
- The level of cash reserves and the governing board's philosophy towards reserves

RATE CLASSES INCLUDED IN THE COMPARISONS

To compare Mountain Lake with other utilities, MRES chose rates that would be charged to customers in the Residential, Commercial, and Large Commercial rate groups. The rates chosen were the basic rates offered by the utilities that would be applicable to the majority of the customers in the classes. These rates are not representative of all the different types of rates that are available.

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SUMMARY OF UTILITY COMPARISON RESULTS

Exhibits 5-A through 5-E at the end of this section contain comparisons between Mountain Lake and the regional utilities whose rates are shown in Exhibits 5-F through 5-H. For utilities with seasonal rates, the bills are the weighted average of all 12 months. For Mountain Lake, the proposed rates for 2024 from Section 4 were used in these comparisons. The comparisons are based on the following levels of usage per month:

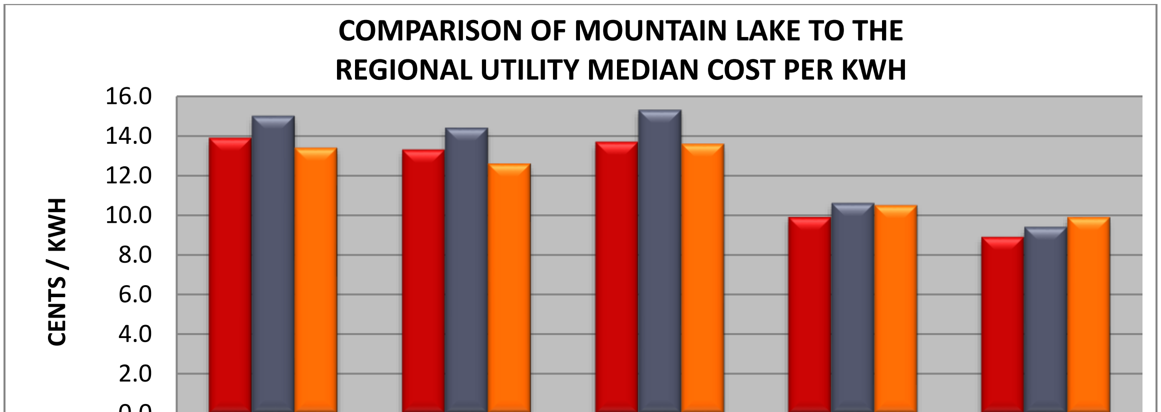
- Residential – Average usage of 750 kWh
- Commercial – Average usage of 1,400 kWh
- Large Commercial – 48,250 kWh and demand of 242 kW (27% Load Factor)
- Large Commercial – 38,500 kWh and demand of 93 kW (57% Load Factor)
- Large Commercial – 831,000 kWh and demand of 1,544 kW (74% Load Factor)

The top portion of each exhibit shows bills calculated using the various utilities' rates, and the bottom portion shows the percentage differences between other utilities and the current Mountain Lake rates.

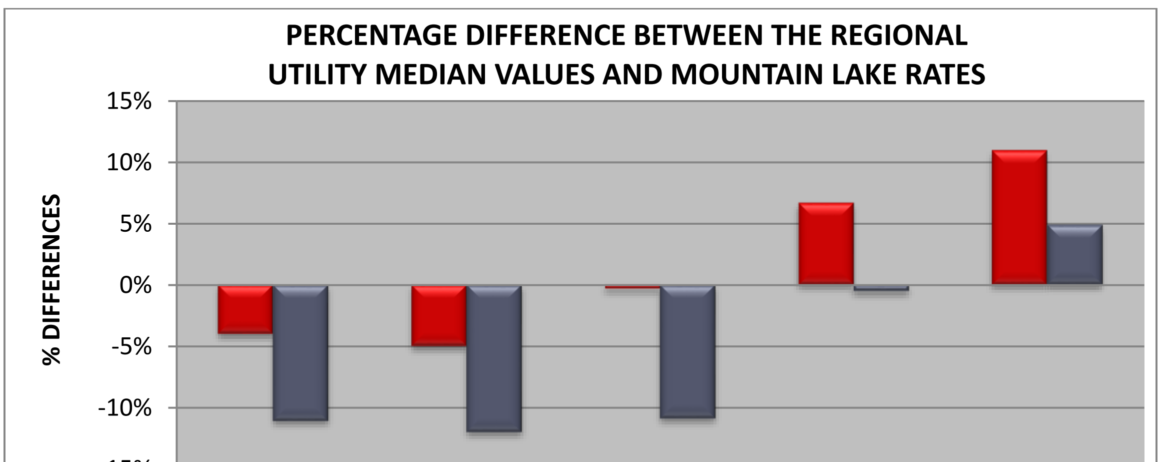
The two graphs on the following page summarize the rate comparison information. The first graph compares cents per kWh for each class using the calculated bills and three sets of values: current Mountain Lake rates, proposed 2024 rates, and the median bill of 10 regional utilities.

The second graph shows the percentage differences between both the Mountain Lake current and proposed rates and the median bill of the 10 utilities. This graph indicates that under current rates, the residential, commercial, and lower load factor large commercial customers are currently above the median. The two large commercial customers with load factors of 57% and 74% are below the median.

SUMMARY OF UTILITY COMPARISON RESULTS (Continued)

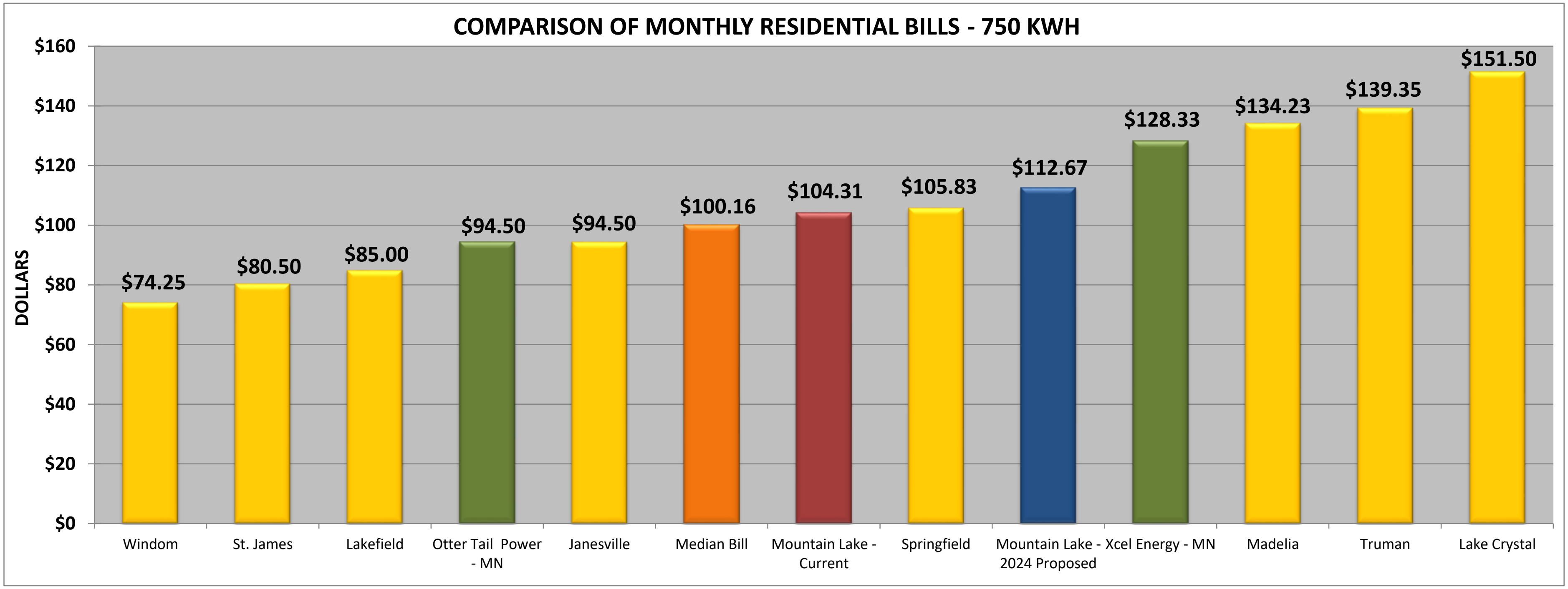


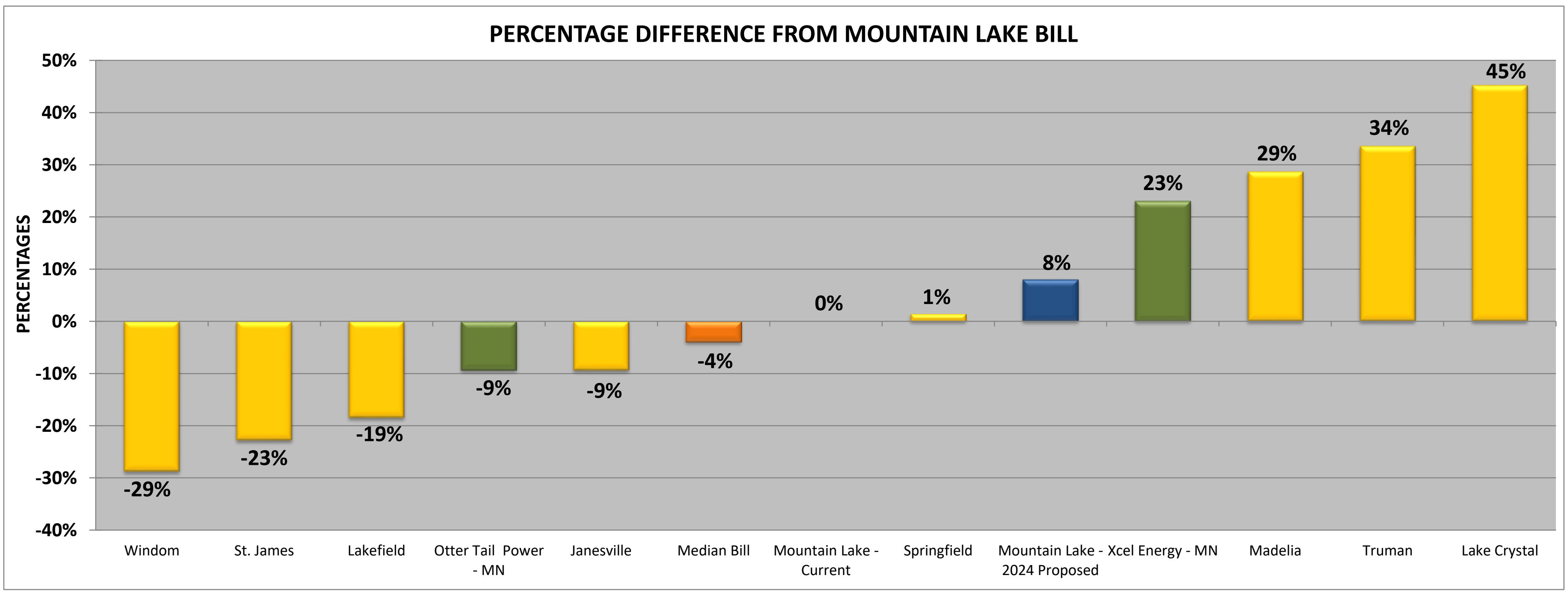
	Residential - 750 kWh	Commercial - 1,400 kWh	Large Commercial - 27% LF	Large Commercial - 57% LF	Large Commercial - 74% LF
Current	13.9	13.3	13.7	9.9	8.9
Proposed	15.0	14.4	15.3	10.6	9.4
Median	13.4	12.6	13.6	10.5	9.9



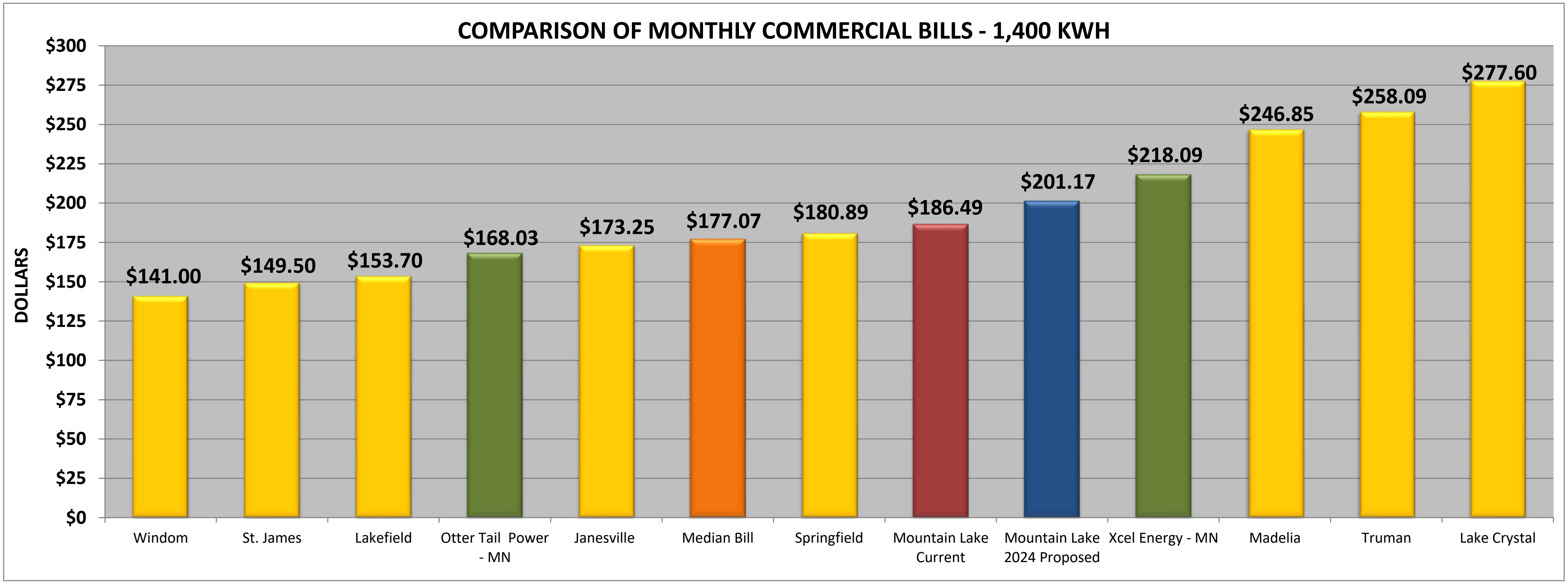
	Residential - 750 kWh	Commercial - 1,400 kWh	Large Commercial - 27% LF	Large Commercial - 57% LF	Large Commercial - 74% LF
Current	-4.0%	-5.0%	-0.3%	6.7%	11.0%
Proposed	-11.1%	-12.0%	-10.9%	-0.5%	4.9%

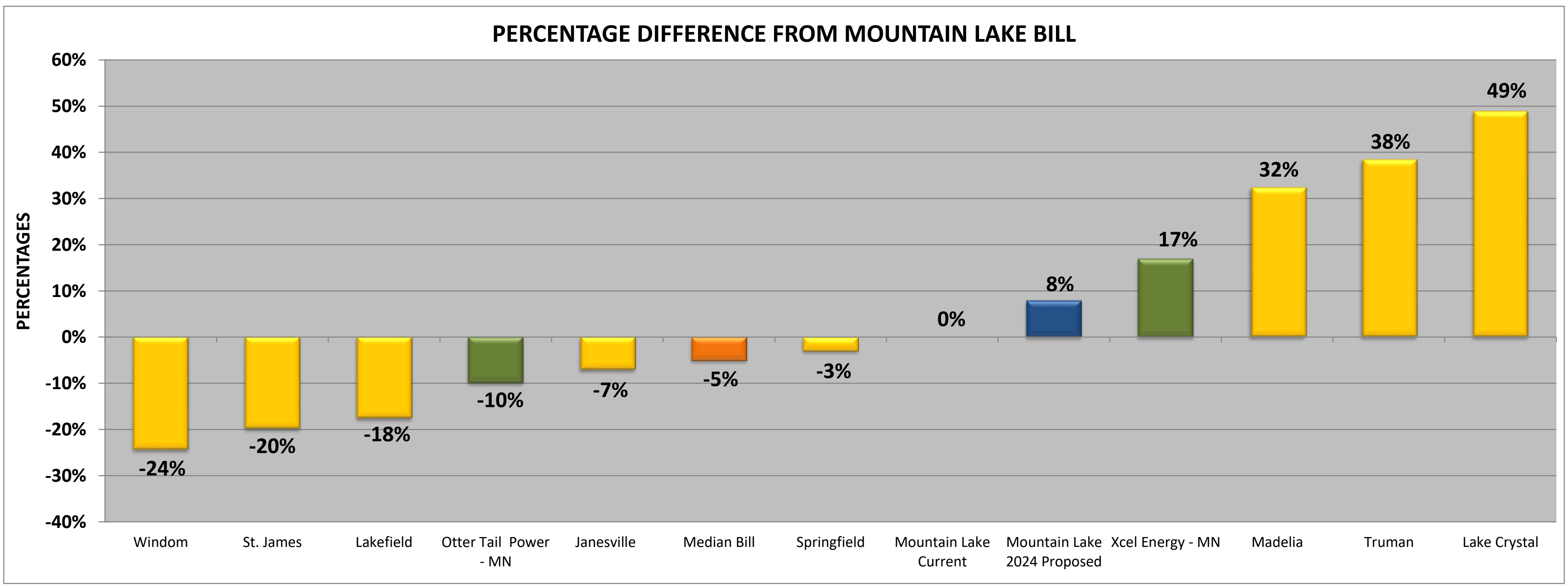
COMPARISON GRAPHS

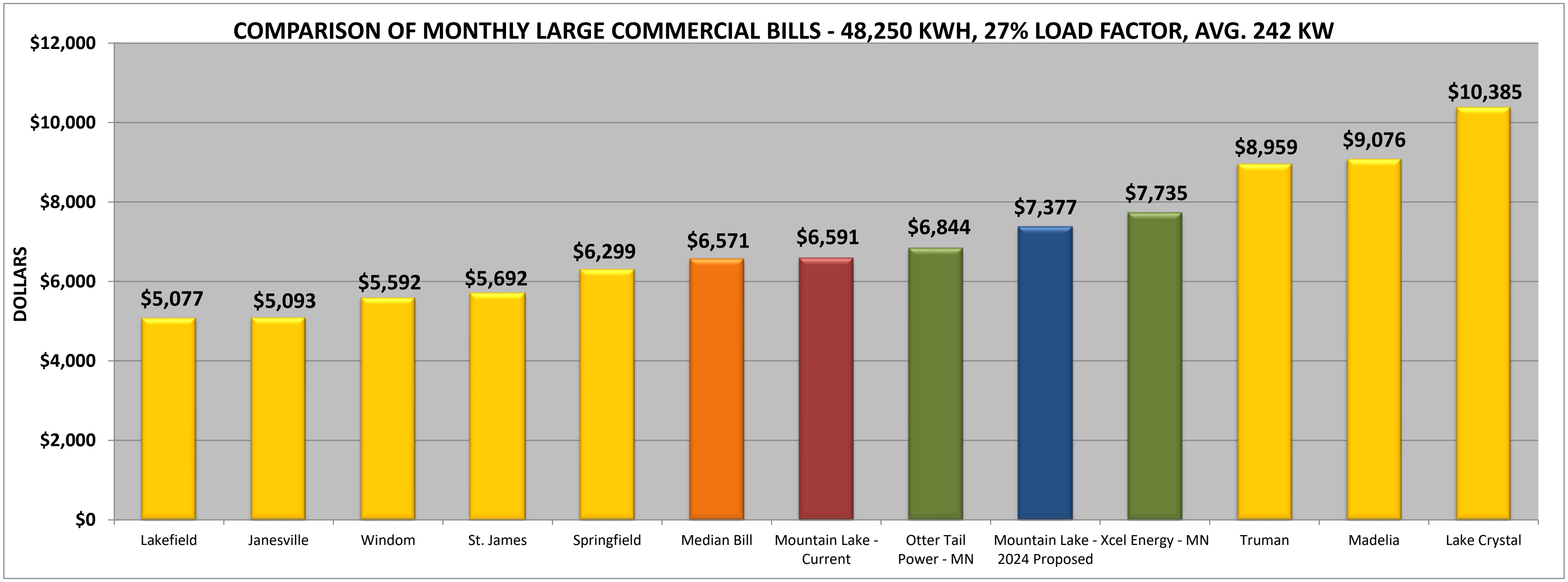


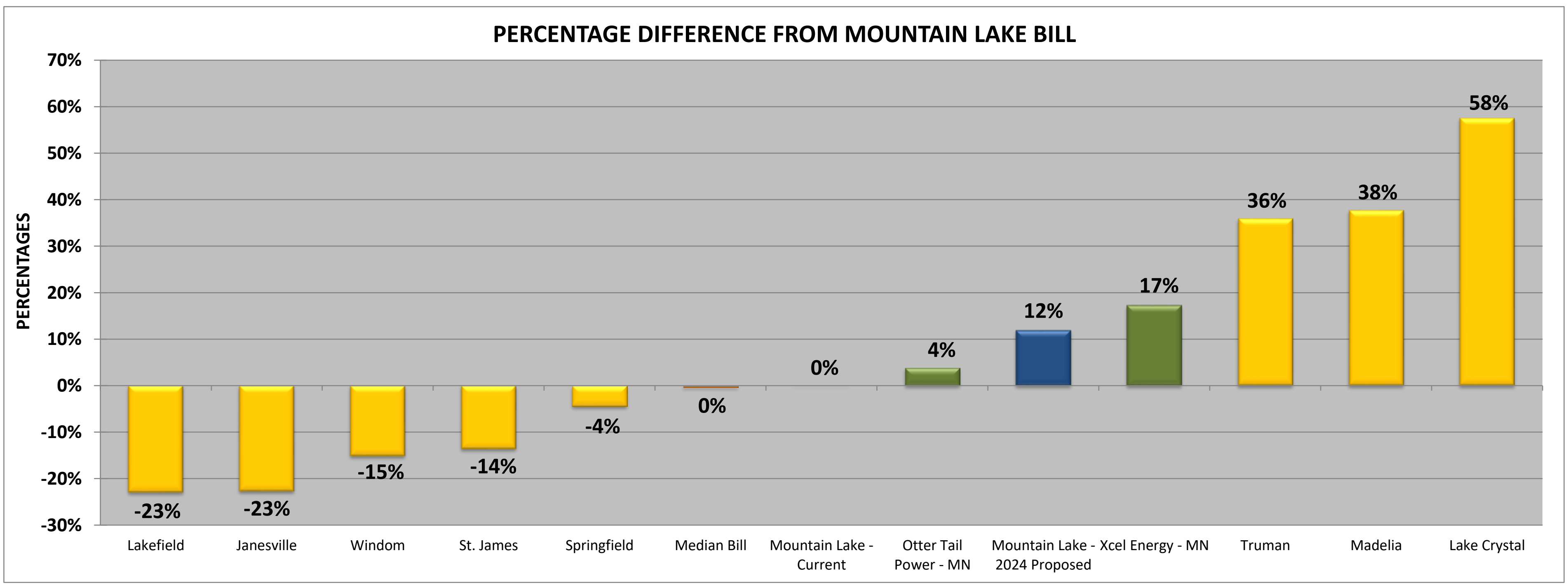


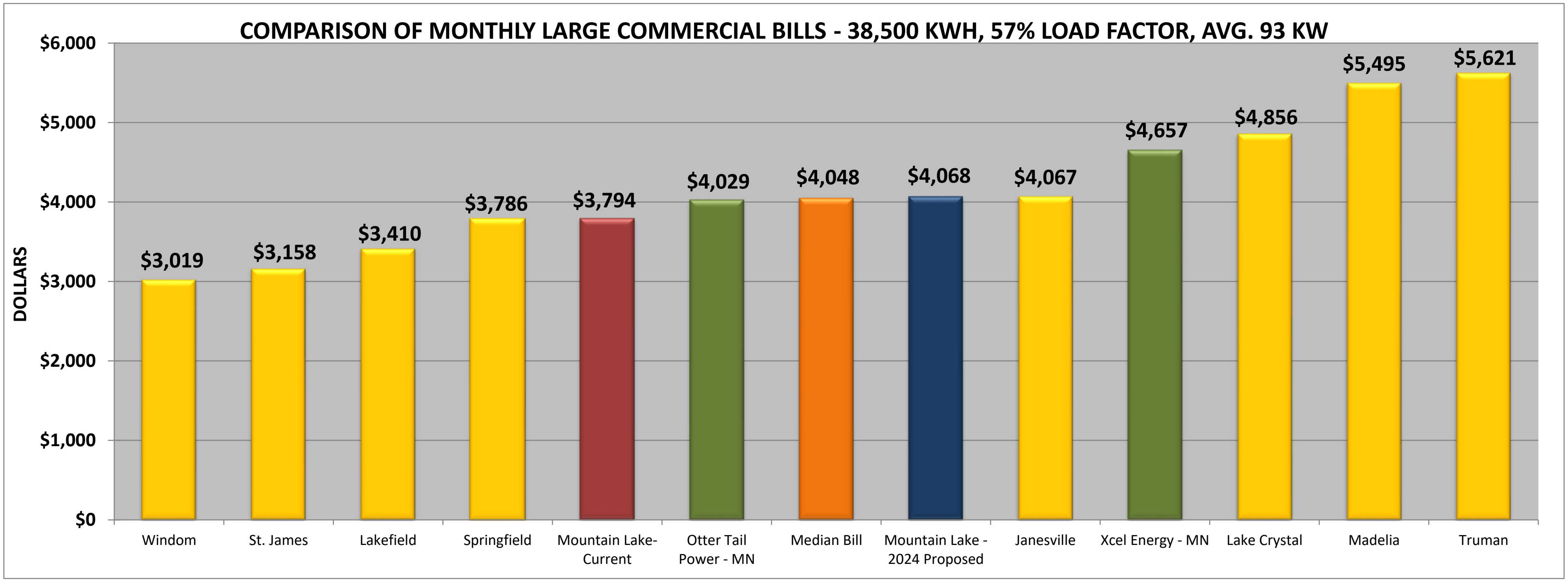
September 2023 - Comparison based on current rates, subject to change. Exhibit 5-A Provided by Missouri River Energy Services

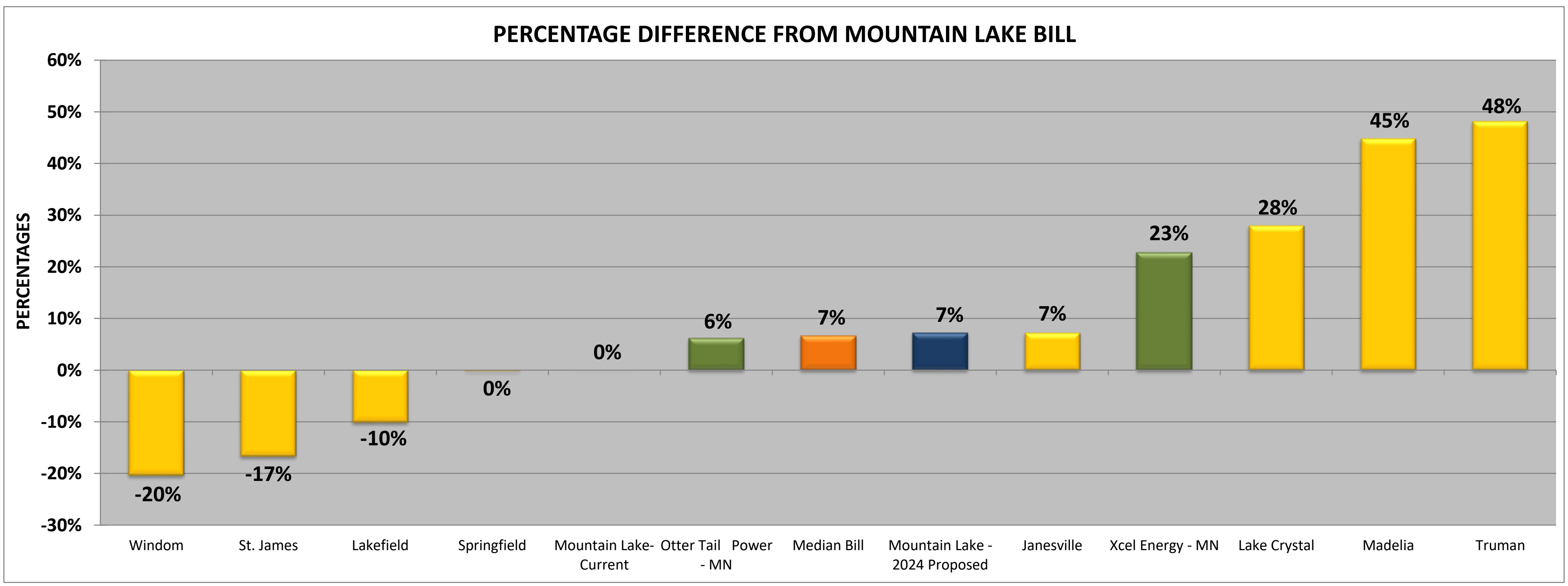

COMPARISON OF MONTHLY COMMERCIAL BILLS - 1,400 KWH
DOLLARS
$300
$275
$250
$225
$200
$175
$150
$125
$100
$75
$50
$25
$0
$141.00
$149.50
$153.70
$168.03
$173.25
$177.07
$180.89
$186.49
$201.17
$218.09
$246.85
$258.09
$277.60
Windom
St. James
Lakefield
Otter Tail Power - MN
Janesville
Median Bill
Springfield
Mountain Lake Current
Mountain Lake 2024 Proposed
Xcel Energy - MN
Madelia
Truman
Lake Crystal

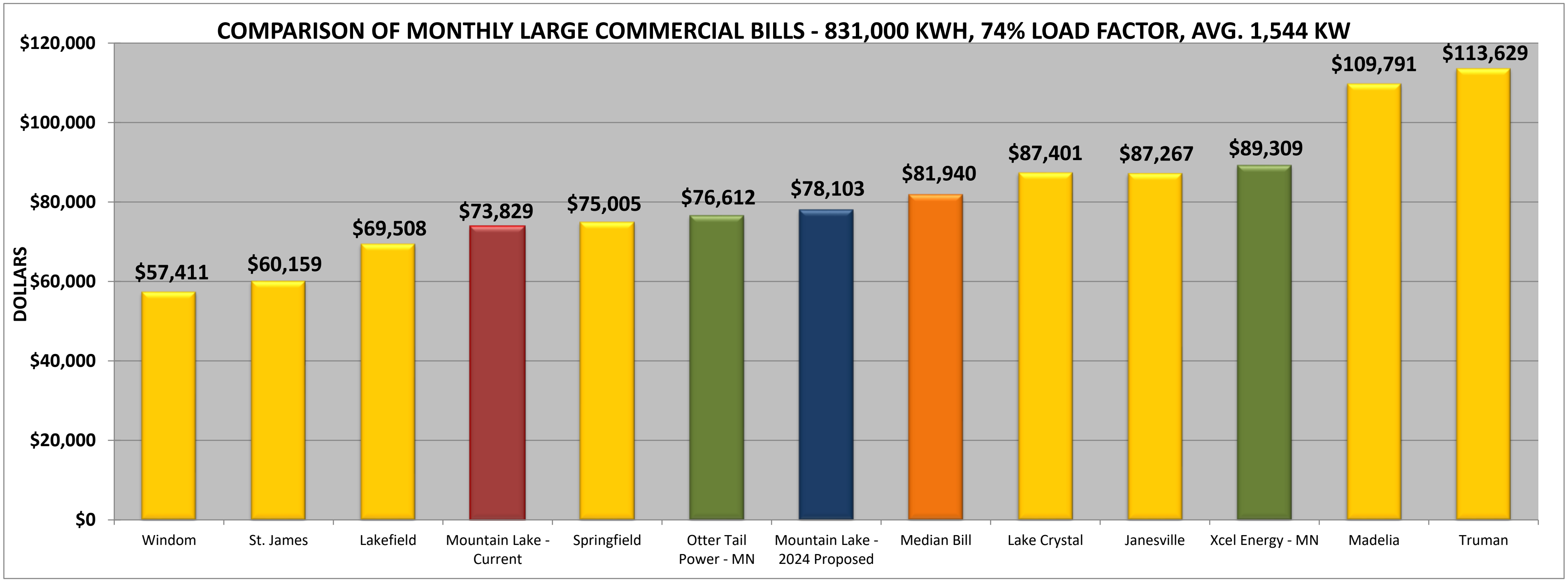

PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-40%
-24%
-20%
-18%
-10%
-7%
-5%
-3%
0%
8%
17%
32%
38%
49%
Windom
St. James
Lakefield
Otter Tail Power - MN
Janesville
Median Bill
Springfield
Mountain Lake Current
Mountain Lake 2024 Proposed
Xcel Energy - MN
Madelia
Truman
Lake Crystal

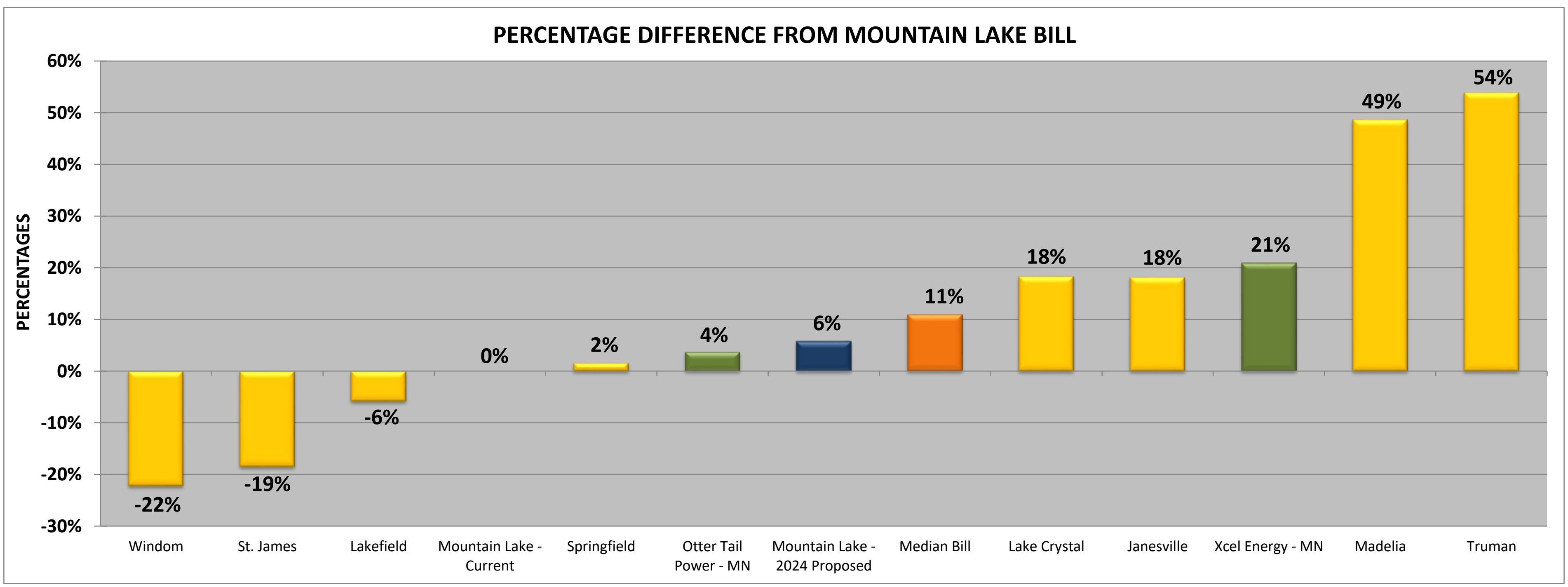

COMPARISON OF MONTHLY LARGE COMMERCIAL BILLS - 48,250 KWH, 27% LOAD FACTOR, AVG. 242 KW
DOLLARS
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
$5,077
$5,093
$5,592
$5,692
$6,299
$6,571
$6,591
$6,844
$7,377
$7,735
$8,959
$9,076
$10,385
Lakefield
Janesville
Windom
St. James
Springfield
Median Bill
Mountain Lake - Current
Otter Tail Power - MN
Mountain Lake - 2024 Proposed
Xcel Energy - MN
Truman
Madelia
Lake Crystal


PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
70%
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-23%
-23%
-15%
-14%
-4%
0%
0%
4%
12%
17%
36%
38%
58%
Lakefield
Janesville
Windom
St. James
Springfield
Median Bill
Mountain Lake - Current
Otter Tail Power - MN
Mountain Lake - 2024 Proposed
Xcel Energy - MN
Truman
Madelia
Lake Crystal


COMPARISON OF MONTHLY LARGE COMMERCIAL BILLS - 38,500 KWH, 57% LOAD FACTOR, AVG. 93 KW
DOLLARS
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$0
$3,019
$3,158
$3,410
$3,786
$3,794
$4,029
$4,048
$4,068
$4,067
$4,657
$4,856
$5,495
$5,621
Windom
St. James
Lakefield
Springfield
Mountain Lake- Current
Otter Tail Power - MN
Median Bill
Mountain Lake - 2024 Proposed
Janesville
Xcel Energy - MN
Lake Crystal
Madelia
Truman


PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-20%
-17%
-10%
0%
0%
6%
7%
7%
7%
23%
28%
45%
48%
Windom
St. James
Lakefield
Springfield
Mountain Lake- Current
Otter Tail Power - MN
Median Bill
Mountain Lake - 2024 Proposed
Janesville
Xcel Energy - MN
Lake Crystal
Madelia
Truman





September 2023- Comparison based on current rates, subject to change. Exhibit 5-E Provided by Missouri River Energy Services

Residential Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$14.57	$0.11760 1.5%	All Conservation Improv. (% of bill)	0.00000
Otter Tail Power – MN	10.75	0.08194 0.06111 0.01471	All (June-Sep.) All (Oct.-May) Other Adjustments: per kWh	0.02722
Xcel Energy – MN Standard Service Electric Space Heating	 10.98 12.98	 0.10301 0.08803 0.05988 0.00562 6.087% 8.92%	 All (June – Sep.) All (Oct. – May) Space Heating All (Oct. – May) Other Adjustments: per kWh Renewable Energy Std. (% of bill) 2022 Interim Increase (% of Bill)	 0.04167
Janesville, MN	15.00	0.10200 5.0%	All Franchise Fee (% of bill)	(0.00200)
Lake Crystal, MN	22.50	0.17200	All	-
Lakefield, MN	14.50	0.10300 0.09100	All (June – August) All (September – May)	-
Madelia, MN	16.00	0.15000 1.5%	All Conservation Improv. (% of bill)	0.00500
Springfield, MN	16.00	0.12700 0.08600 1.5%	All Heating (Oct.-April) Conservation Improv. (% of energy charges)	(0.00900)
St. James, MN	19.00	0.08200	All	-
Truman, MN	11.85	0.17000 1.5%	All Conservation Improv. (% of energy charges)	-
Windom, MN In City Limit	 15.00	 0.07900	 All	 -

Commercial Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$24.97	$0.11340 1.5%	All Conservation Improv. (% of bill)	0.00000
Otter Tail Power – MN	18.50	0.07546 0.05595 0.01484	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh	0.02698
Xcel Energy – MN	11.27	0.09256 0.07757 0.00520 6.087% 13.52%	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh Renewable Energy Std. (% of bill) 2022 Interim Increase (% of Bill)	0.04219
Janesville, MN	25.00	0.10200 5.0%	All Franchise Fee (% of bill)	(0.00200)
Lake Crystal, MN	41.00	0.16900	All	-
Lakefield, MN	20.00	0.01030 0.09300	All (June – August) All (September – May)	-
Madelia, MN	22.00	0.1530 1.5%	All Conservation Improv. (% of bill)	0.00500
Springfield, MN	26.00	0.11800 1.5%	All Conservation Improv. (% of energy charges)	(0.00900)
St. James, MN Single-phase Three-phase	 23.50 40.00	0.09000	All	-
Truman	20.09	0.17000 1.5%	All Conservation Improv. (% of bill)	-
Windom, MN Single-phase Three-phase	 22.00 31.00	0.08500	All	-

Exhibit 5-H

Large Commercial Rates

Utility	Monthly Service Charge	Demand Charge (per kW)	Demand Block (kW-mos.)	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$57.22	$14.57	All	$0.0604 1.5%	All Con. Improv. (% of bill)	0.00000
Otter Tail Power – MN 20 kW-80 kW Over 80 kW	 42.55 104.63 (Min. 350.00)	 2.00 1.00 1.50 13.99 11.25 1.03 0.67 1.443	 June-Sep. Oct.-May Facility Chg. June-Sep. Oct.-May Facility Chg. <1,000 Facility Chg. >1,000 Other Adj.	 0.04644 0.05272 0.01489 0.02590 0.02950 0.0105	 All (June-Sept.) All (Oct.-May) Other Adjustments All (June-Sept.) All (Oct.-May) Other Adjustments	 0.02698 0.02632
Xcel Energy – MN Less than 1 MW	29.24	14.79 10.49 0.984	June–Sep. Oct.–May 50% Ratchet Other Adj.	0.03407 (0.01518) 0.00201 6.087% 13.52%	All Over 400 kWh/kW Other Adjustments Renew. Energy Std. 2022 Interim Inc.	0.04088
Janesville, MN	25.00	-	All	0.10200 5.0%	All Franchise Fee	(0.00200)
Lake Crystal, MN	67.50	34.50	All	0.04100	All	-
Lakefield, MN	30.00	9.00 6.00	June – August September - May	0.07100	All	-
Madelia, MN Large Commercial Industrial	 32.00 170.00	 17.30 26.40	 All All	 0.09300 0.07000 1.5%	 All All Con. Improv. (% of bill)	 0.00500
Springfield, MN	45.00	12.50	All	0.07500 1.5%	All Con. Improv. (% of energy charges)	(0.00900)
St. James, MN	73.50	14.00	All	0.04630	All	-
Truman, MN	28.33	15.35	All	0.10820 1.5%	All Con. Improv. (% of bill)	-
Windom, MN	49.00	14.45	All	0.04200	All	-