MONTANA-DAKOTA UTILITIES CO.

Before the Public Utilities Commission of South Dakota

Docket No. NG23-___

Direct Testimony

Of

Nicole A. Kivisto

Q. **Please state your name and business address.**

A. My name is Nicole A. Kivisto and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. **By whom are you employed and in what capacity?**

A. I am the President and Chief Executive Officer (CEO) of Montana-Dakota Utilities Co. (Montana-Dakota or Company), Cascade Natural Gas Corporation, and Intermountain Gas Company, all subsidiaries of MDU Resources Group, Inc., and Great Plains Natural Gas Co., a division of Montana-Dakota, collectively the MDU Utilities Group.

Q. **Please describe your duties and responsibilities with MDU Utilities Group.**

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above-mentioned companies that, in combination, serve over 1.182 million customers in eight states.

Q. Please outline your educational and professional background.

A. I hold a Bachelor's Degree in Accounting from Minnesota State University Moorhead. I began working for MDU Resources/Montana-Dakota in 1995 and have been in my current capacity since January 2015. I was the Vice President-Operations of Montana-Dakota and Great Plains from January of 2014 until assuming my present position.

Prior to that, I was the Vice President, Controller, and Chief Accounting Officer for MDU Resources for nearly four years and held other finance related positions prior to that.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of North Dakota, Montana, and Wyoming, the Public Utilities Commissions of Idaho and Minnesota, the Public Utility Commission of Oregon and the Washington Utilities and Transportation Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Montana-Dakota's gas operations in the state of South Dakota. I will also provide an overview of the Company's request for a gas rate increase and discuss the policies and reasons underlying the major aspects of the request. Finally, I will introduce the other Company witnesses who will present testimony and exhibits in further support of the Company's request.

Q. Would you provide a summary of Montana-Dakota's gas operations in South Dakota?

A. Montana-Dakota provides natural gas service to approximately 64,600 customers in 26 communities in South Dakota, operating approximately 1,544 miles of distribution mains and approximately 1,184 miles of service lines. The customer base is 88 percent residential and 12 percent commercial and industrial. As of December 31, 2022, the Company had 73 full and part-time employees who live and work throughout our South Dakota electric and gas service area.

Montana-Dakota’s South Dakota gas service area is divided into two operating regions with regional offices located in Rapid City, South Dakota and Bismarck, North Dakota and a number of smaller district offices located in communities throughout South Dakota.

Montana-Dakota’s customers have toll-free access to the Customer Experience Team and the Credit Center to place routine utility service requests and inquiries from 7:30 am to 6:30 pm local time, Monday through Friday and emergency calls on a 24-hour basis. A scheduling center, part of the Customer Experience Team, transmits electronic service orders to the mobile terminals placed in our fleet of service and construction vehicles. This network allows the Company to respond quickly to customer requests and emergency situations.

Q. Would you please provide more information regarding the customers the Company serves?

A. Yes. The residential, firm general service, and small interruptible customers use natural gas primarily for space and water heating. As such, Montana-Dakota's system has a low load factor with peak gas requirements occurring during the winter. Summer loads are small by comparison. Montana-Dakota is projecting to deliver approximately 8.9 Mmdk of natural gas to customers in South Dakota in 2023. The natural gas requirements by customer class is as follows: approximately 43 percent residential, 36 percent firm general service, 4 percent small interruptible, and 17 percent large interruptible.

Q. Would you please describe the basic elements that make up the total costs of providing natural gas service?

A. For a natural gas distribution utility, the basic elements which make up the cost of providing natural gas service are the cost of gas delivered at the town border stations in its service territory and the cost of distributing the gas from the town border station to the end use customer. It is the second of these two elements, the distribution costs, which are the subject of this application for a general rate increase.

The natural gas the Company purchases from suppliers is a commodity like wheat or corn, the price of which is not regulated. The cost of delivering the gas to the Company's distribution system at the town border station is regulated by the FERC or other regulatory agencies.

These gas costs are passed on to customers on a dollar-for-dollar basis as specified in the Commission approved Purchased Gas Cost Adjustment tariff. The gas portion of the cost of providing natural gas service currently comprises about 65 percent of a typical residential bill for gas service.

The distribution cost portion of the Company's cost of service is the subject of this proceeding. This element includes the costs of new distribution investments, replacement of aging infrastructure, operation and maintenance expenses, depreciation, taxes, and the opportunity to earn a return on the Company's investments in facilities that provide natural gas service. Distribution costs are currently 35 percent of a typical residential bill.

Q. Ms. Kivisto, did you authorize the filing of the rate application in this proceeding?

A. Yes, I did.

Q. Why has Montana-Dakota filed this application for a natural gas rate increase?

A. Montana-Dakota is requesting an increase in its gas rates because our current rates do not reflect the cost of providing natural gas service to Montana-Dakota's South Dakota customers. For the twelve months ending December 31, 2022, the Company's Rate of Return was 3.858 percent. This is below the last authorized Rate of Return of 7.216 percent in Docket No. NG15-005.

Q. When was the Company's last general rate case?

A. The Company's last rate case was filed eight years ago in Docket No. NG15-005, which resulted in an increase of $1.2 million or a 2.45 percent overall increase. Final rates in the case became effective on July 1, 2016.

Q. What is the amount of the increase requested?

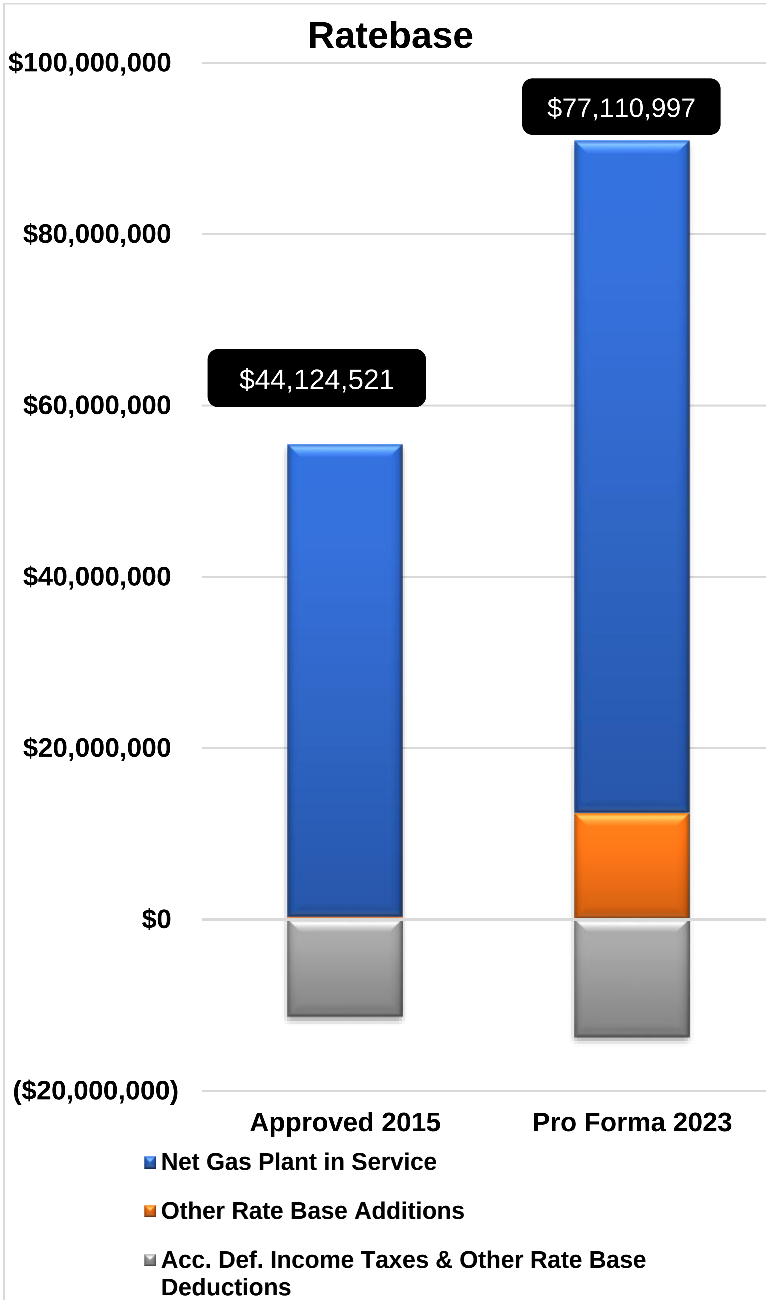
A. As will be fully explained by other Company witnesses, the Company is requesting $7,420,480 which represents an 11.2 percent increase based on a 2022 test year adjusted for known and measurable changes. This increase represents an average yearly increase of 1.4 percent per year.

Q. How would this increase effect the Company's residential customers?

A. The Company's residential class of customers would see an increase of 15.9 percent, or an increase of approximately 2 percent per year. As a result, an individual residential customer using 5.5 Dk per month will see an increase of approximately $8.70 per month.

Q. What are the primary reasons that Montana-Dakota needs an increase at this time?

A. The need for an increase in gas rates is driven primarily by the investments made since the last rate case and increases in O&M expenses. As depicted in the graph below, the Company's net adjusted rate base has grown approximately $33 million or 75 percent since the approved 2015 rate base.



As shown in the table below, the Company's total O&M costs have increased over those approved in the Company's last gas rate case. After adjusting the 2015 Authorized O&M to exclude the costs associated with cost of gas, the Company's Pro Forma O&M expenses are projected to increase approximately 48 percent. This represents a 5.7 percent compounded increase per year since the last filing.

	Approved 2015	Pro Forma 2023	Variance	Percent Variance
Cost of Gas	$32,640,945	$46,787,331	$14,146,386	43.34%
Labor	5,277,104	7,061,225	1,784,121	33.81%
Benefits	1,318,452	1,349,539	31,087	2.36%
Subcontract Labor	707,829	1,808,823	1,100,994	155.55%
Materials	265,622	490,438	224,816	84.64%
Vehicles and Work Equipment	343,276	1,175,139	831,863	242.33%
Insurance	279,648	492,060	212,412	75.96%
Software Maintenance	167,644	615,778	448,134	267.31%
Other O&M	1,480,719	1,529,622	48,903	3.30%
Total O&M Expense	$42,481,239	$61,309,955	$18,828,716	44.32%
Total Excluding Cost of Gas	$9,840,294	$14,522,624	$4,682,330	47.58%

Q. How have the Company's labor expenses changed since the last case?

A. Montana-Dakota's projected labor expenses for the year ending December 2023 have increased approximately 34 percent since the approved 2015 rate case which represents a 3.71 percent compounded year over year increase.

Additionally, Montana-Dakota, like many other organizations in the country, has struggled to recruit, train, and retain personnel in the current competitive job market. Furthermore, the Company has faced increased labor market costs, particularly for those in entry level positions.

In late 2021 Montana-Dakota finalized its labor contract with the System Council U-13 of the IBEW. This contract, which runs through April

2024, defined an approximately 3.00 percent labor expense increase per year, and its effect is discussed in the testimony of Ms. Vesey.

Q. Have there been other increases in expenses since the last case?

A. Montana-Dakota has seen other increases to O&M expenses since the last case, such as subcontract labor, vehicles and work equipment, and software maintenance. The operation and maintenance expenses associated with subcontract labor have increased approximately $1.1 million primarily for third party line locating and reconnecting meters. Vehicles and Work equipment increased approximately $832,000 primarily due to increased depreciation rates for Power Operated Equipment within the study supported by Mr. Kennedy. Software maintenance expense increased approximately $448,000 from the approved 2015 rate case due to increases in subscription renewals and mandated security needs.

Q. Have you performed a depreciation study for inclusion in this request?

A. Yes. Depreciation studies for Montana-Dakota's gas and common plant in service were performed by Mr. Larry Kennedy of Concentric Advisors, ULC. Mr. Kennedy has provided testimony on behalf of the Company and is recommending a composite gas plant depreciation rate of 3.77 percent and a 5.31 percent common depreciation rate, both of which are based on plant in service as of December 31, 2021. The impact of the depreciation study results in a South Dakota gas jurisdiction increase of approximately $153,000 in the revenue requirement, as compared to the previously approved rates.

Q. What other adjustments are contributing to the need for an increase in distribution rates?

A. In addition to the increase in rate base and the associated operating expenses including the updated depreciation rates, the Company is requesting the inclusion of the provision for pension and benefits, provision for post retirement, and a cash working capital adjustment, net of the associated deferred taxes, to be added to rate base.

Q. Why has the Company proposed to include the pension and benefits and post retirement regulatory assets in rate base at this time?

A. The cash contributions made by the Company have significantly exceeded the pension expense, which is the amount included in the Company's revenue requirement as a component of O&M expenses and recovered through rates charged to customers. Similar to other investments, Montana-Dakota has a significant outlay in cash and its only opportunity to earn a return on the outlay of cash is by inclusion in the Company's rate base.

Montana-Dakota has taken a number of steps to minimize pension costs, including closing the pension plan to new participants and freezing the level of benefits accrued.

The post retirement prepaid asset, while much smaller in size, has similar characteristics as the prepaid pension asset and was included in the pro forma rate base as well.

Due in large part to the Company's recent contributions, pension and post retirement annual expenses have been reduced as they are recovered through the revenue requirement. In this case, pension and post retirement reflect approximately a negative cost of $236,000 which is a savings to customers and largely offsets the inclusion of the pension and post retirement net assets.

The inclusion of pension and post retirement is fully explained by Ms. Vesey.

Q. Has the Company added any other new adjustments to be considered?

A. Montana-Dakota has included a Cash Working Capital adjustment that reduces the rate base by approximately $395,400. This adjustment reduces the revenue requirement by approximately $36,000.

This adjustment will be more fully explained by Mr. Adams and Ms. Vesey.

Q. You have discussed a number of items, can you briefly explain the additional revenue requirement?

A. In summary, as shown in the table below, the $7.4 million increase in revenue is driven primarily by:

	Amount (in millions)
O&M Increase	$4.7
Rate Base	$1.0
SSIP	$0.4
Depreciation Increase	$1.5
Income Tax Reduction	($0.3)
Other	$0.1
	$7.4

Montana-Dakota's cost of doing business in South Dakota is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $4.7 million increase in O&M expenses due to increased labor, subcontract labor, vehicles and work equipment, and software maintenance. Other plant additions, including System Safety Integrity Program (SSIP), represents another $1.4 million increase. Finally, increases in depreciation expense, primarily driven by the implementation of the updated depreciation studies, result in a revenue requirement increase of approximately $1.5 million.

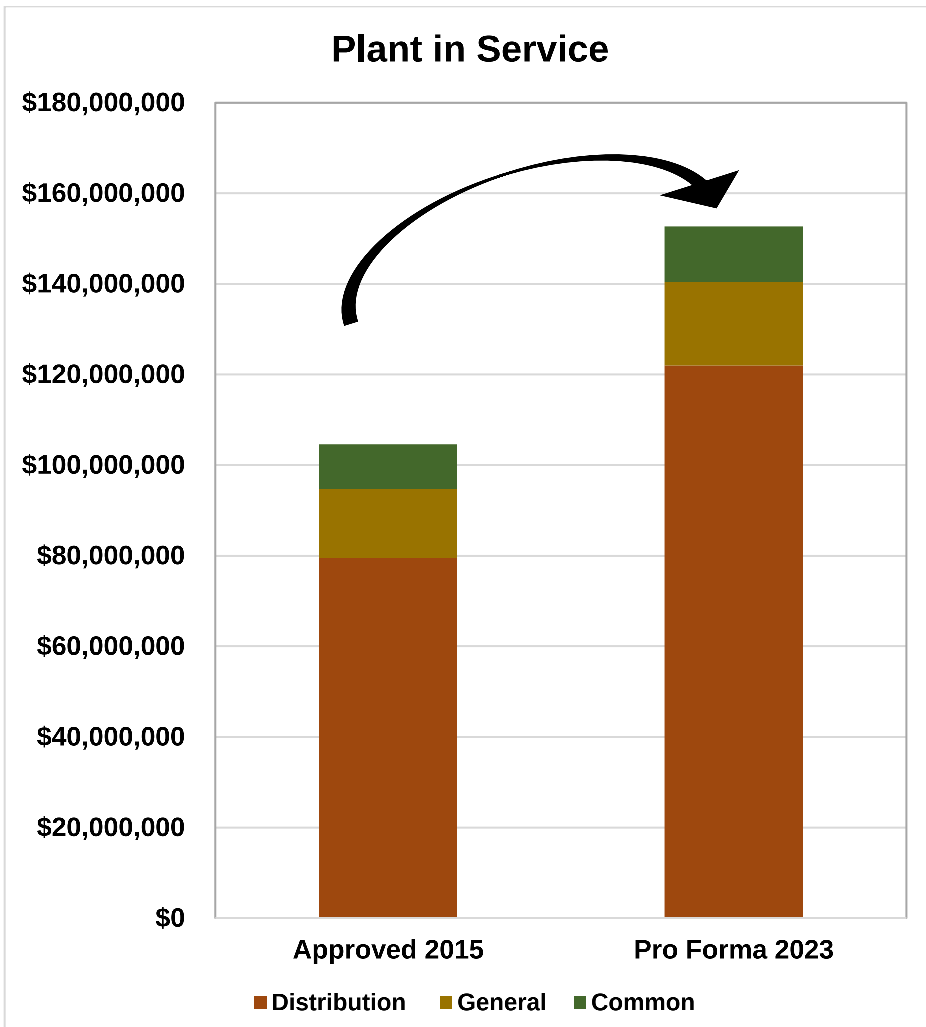
Q. What incremental investments are included in this case as pro forma December 2023?

A. The Company has included incremental investments for 2023 of approximately $10.3 million and are associated with the following investments:

- Distribution investment of approximately $8.8 million including distribution mains and service line replacements and upgrades required to maintain reliable service, as discussed in greater detail by Mr. Nishikawa and Mr. Volk;

- General and common plant additions of approximately $1.5 million primarily associated with work equipment, structures, and improvements.

The table below shows the investment in plant assigned and allocated to South Dakota gas operations from 2015 to pro forma 2023.



Q. Would you please describe the investment in distribution facilities to improve system safety and integrity in greater detail?

A. The investment in system safety and integrity is a focused effort based on the Company's Distribution Integrity Management Program (DIMP). Mr. Volk will explain in further detail how the DIMP is used to identify the pipeline replacement projects necessary for safety reasons and to reduce risk on Montana-Dakota's system.

Q. How will the requested increase affect the various classes of customers?

A. The allocation of revenue is based on the Class Cost of Service Study, which is supported by Mr. Amen. The proposed percentage change in rates by customer class are as follows:

Rate Class	Overall Class Impact
Residential Service	15.9%
Firm General Service	4.9%
Small Interruptible Service	1.9%
Large Interruptible Service	6.1%
Total	11.2%

Q. What return is Montana-Dakota requesting in this case?

A. Montana-Dakota is requesting an overall return of 7.600 percent, inclusive of a return on equity (ROE) of 10.5 percent. Mr. Wall's analysis indicates that a 10.5 percent ROE is fully justified and supported based on the results of his studies.

Q. Will you please identify the witnesses who will testify on behalf of Montana-Dakota in this proceeding?

A. Yes. Following is a list of witnesses who will provide testimony and/or exhibits in support of the Company's application:

- Ms. Tammy J. Nygard, Controller for Montana-Dakota, will testify regarding the overall cost of capital, capital structure, and overall debt costs.
- Mr. Christopher M. Wall, Senior Associate of The Brattle Group, will testify regarding the appropriate cost of common equity for Montana-Dakota's South Dakota gas operations.
- Mr. Larry E. Kennedy, Senior Vice President for Concentric Advisors, ULC., will testify regarding the depreciation studies for Montana-Dakota's gas and common operations of the plant in service as of December 31, 2021, that supports the proposed depreciation rates in this filing.
- Mr. Michael J. Adams, Senior Vice President for Concentric Energy Advisors, Inc., will testify regarding Montana-Dakota's lead lag study and cash working capital adjustment.
- Mr. Russel Nishikawa, Engineering Services Manager for Montana-Dakota will testify regarding South Dakota gas distribution capital expenditures.

- Mr. Jesse Volk, System Integrity Manager for Montana-Dakota will testify regarding South Dakota gas System Safety and Integrity capital expenditures.
- Mr. Nathan A. Bensen, Regulatory Analyst for Montana-Dakota will testify regarding the pro forma volumes in this case.
- Ms. Tara R. Vesey, Regulatory Affairs Manager for Montana-Dakota, will testify regarding the total revenue requirement.
- Mr. Ron J. Amen, Managing Partner for Atrium Economics, LLC, will testify regarding Montana-Dakota's embedded class cost of service study and proposed rate design.
- Ms. Stephanie Bosch, Regulatory Affairs Manager for Montana-Dakota, will testify regarding proposed tariff changes.

Q. Ms. Kivisto, are the rates requested in this proceeding just and reasonable?

A. Yes. In my opinion, the proposed rates are just and reasonable as they are reflective of the total costs being incurred by Montana-Dakota to provide safe and reliable natural gas service to its customers. The proposed rates will provide Montana-Dakota the opportunity to earn a fair and reasonable return on its South Dakota gas operations.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-___

Direct Testimony

Of

Tammy J. Nygard

Q. Please state your name and business address.

A. My name is Tammy J. Nygard and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. By whom are you employed and in what capacity?

A. I am the Controller for Montana-Dakota Utilities Co. (Montana-Dakota), Cascade Natural Gas Corporation (Cascade) and Intermountain Gas Company (Intermountain), subsidiaries of MDU Resources Group, Inc. (MDU Resources) as well as Great Plains Natural Gas Co. (Great Plains), a division of Montana-Dakota, collectively the MDU Utilities Group.

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Montana-Dakota, Great Plains, Cascade, and Intermountain.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 20 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

Q. What is the purpose of your testimony in this proceeding?

A. I am responsible for presenting Statement A, Statement B, Statement C and Statement G.

Q. Were these statements and the data contained therein prepared by you or under your supervision?

A. Yes, they were.

Q. Are they true to the best of your knowledge and belief?

A. Yes, they are.

Q. Would you please explain Statement A, Statement B and Statement C?

A. Statement A, page 1 and 2 show Montana-Dakota's balance sheet as of December 31, 2021 and December 31, 2022 and June 30, 2022 and June 30, 2023 information shown on pages 3 and 4, with notes to the financial statements following. Statement B consists of Montana-Dakota's income statement for the twelve months ended December 31, 2022 and the six months ended June 30, 2023. Statement C presents the changes in retained earnings from December 31, 2021 to December 31, 2022. These statements have been prepared from the Company's books and records that are maintained in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. Would you please explain Statement G?

A. Statement G, Rule 20:10:13:72, summarizes the average utility capital structure and the related costs of debt and common equity of Montana-Dakota for the twelve months ended December 31, 2022 and the pro forma capital structure for 2023. This capital structure and the associated costs serve as the basis for the overall rate of return requested by Montana-Dakota in this rate filing of 7.600 percent. The basis for the requested 10.5 percent return on common equity contained within the overall requested rate of return is supported by the testimony of Ms. Ann Bulkley.

The components of the 2023 pro forma overall annual rate of return, which are used by Ms. Vesey to calculate the revenue requirement, are:

	Weighted Cost of Capital
Long Term Debt	1.997%
Short Term Debt	0.312%
Common Equity	5.291%
Required Rate of Return	7.600%

Q. How does the Company finance its gas utility operations and determine the amount of common equity and debt to be included in its capital structure?

A. As a regulated public utility, the Company has a duty and obligation to provide safe and reliable service to its customers across its service territory while prudently balancing cost and risk. In order to fulfill its service obligations, the Company has made significant capital expenditures for new plant investment throughout its service territory, especially in mains and services, including System Safety and Integrity Projects (SSIP). These new investments also have associated operating and maintenance costs. Through its financial planning process, the Company determines the amounts of necessary financing required to support these activities. Montana-Dakota finances its operations targeting a 50 percent common equity capital structure at year end. Capital expenditure investments are financed through a mix of internally generated funds, the utilization of the Company's short-term credit line and the issuance of additional long-term debt and common equity financing as required to maintain targeted capital ratios and finance the combined utility operations.

The Company did not obtain any additional common equity in 2022. In order to achieve and maintain the targeted capital structure, the Company is expecting to receive approximately $40.0 million of common equity in 2023.

The Company did not issue any new long-term debt in 2022 and is not expecting to issue any new long-term debt in 2023.

Q. What does Statement G, Rule 20:10:13:73 show?

A. Page 1 is a summary showing the Company's long-term debt at December 31, 2021 and 2022 and associated cost of debt, and it shows the pro forma long-term debt and associated costs for 2023, as well as the average cost of debt for the two periods. Page 2 shows the cost and the debt balance by issue at December 31, 2022 and page 3 shows the pro forma cost and the debt balance by issue at December 31, 2023.

Q. How did you derive the pro forma cost of debt for 2023?

A. The pro forma cost of debt for 2023 is based upon the yield-to-maturity of each debt issue outstanding.

Q. Would you please describe Statement G, Rule 20:10:13:73, page 4 and explain the amortization method utilized?

A. Page 4 reflects the annual amortization of the costs associated with the redemption of long-term debt. For this proceeding, the amortization has been computed on a straight-line basis over the remaining life of the issues. The balance was fully amortized in May 2022. The Company uses the same calculation for accounting purposes.

Q. Would you please describe Statement G, Rule 20:10:13:73, page 5?

A. Page 5 presents the twelve-month average short-term debt balance for 2022 and pro forma 2023 as well as the average cost of short-term debt. A twelve-month average of short-term debt is used in the cost of capital calculation to reflect the seasonality in the short-term debt balance. Short-term debt is historically at or near its peak in December and the twelve-month average calculation is more reflective of the borrowing level than a year-end balance.

Q. What does Statement G, Rule 20:10:13:74 show?

A. Montana-Dakota has reacquired all preferred stock; therefore, this Statement is no longer applicable to Montana-Dakota.

Q. What does Statement G, Rule 20:10:13:75 show?

A. Page 1 reflects the Company's common equity balance at December 31, 2021 and 2022 and the pro forma balance for December 31, 2023. The changes to the common equity balances reflect the normal changes, including projected earnings, as well as the effect of new capital/equity infusions.

Q. What does Statement G, Rule 20:10:13:75, page 2 show?

A. The schedule shows the issuance of common stock during the five year period ending December 31, 2022. As a result of the MDU Resources holding company reorganization that was effective January 1, 2019, Montana-Dakota no longer has publicly traded common stock.

Q. What does Statement G, Rule 20:10:13:76, Schedule G-1 show?

A. This schedule shows that there has been no stock split or stock dividend activity in the five years ended December 2022.

Q. What does Statement G, Rule 20:10:13:77, Schedule G-2 show?

A. This schedule presents various financial and market data relative to the Company’s common stock for the years ended 2018 through 2022. As noted above, on January 1, 2019, MDU Resources completed the holding company reorganization, which resulted in MDU Resources becoming a holding company and indirectly owning all of the outstanding capital stock of Montana-Dakota.

Q. What does Statement G, Rule 20:10:13:78, Schedule G-3 show?

A. This schedule shows the reacquisition activity for long-term debt in the last five years and shows the Company does not have any preferred stock.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
DOCKET NO. NG23-___
PREPARED DIRECT TESTIMONY OF
CHRISTOPHER M. WALL

Q1. Please state your name and business address.

A1. My name is Christopher M. Wall. My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108. I am employed by The Brattle Group ("Brattle") as a Senior Associate.

Q2. Please describe your education and experience.

A2. I hold a B.A. in Mathematics and Economics from Saint Peter's College where I graduated Summa Cum Laude and a Master's degree in Economics from Northeastern University. I have more than ten years of experience consulting in the energy industry and have been involved with numerous topics for rate regulated natural gas, water, and electric utilities in North America, including cost of capital, cost of service, demand forecasting, and rate design. The majority of my assignments over the past few years have focused on the determination of the cost of capital for ratemaking purposes. I have also included my resume and a summary of the testimony I have filed in other proceedings in Exhibit No. ___(CMW-2), Schedule 1.

Q3. On whose behalf are you submitting this testimony?

A3. I am submitting this direct testimony before the South Dakota Public Utilities Commission ("Commission") on behalf of Montana-Dakota Utilities Co. My testimony addresses the regulated gas utility operations of Montana-Dakota Utilities Co. in South Dakota ("Montana-Dakota" or the "Company").

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. Please describe the purpose of your testimony.

A4. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding Montana-Dakota's return on equity ("ROE") for its natural gas utility operations in South Dakota to be used for ratemaking purposes. I also address the appropriateness of the Company's proposed capital structure.

Q5. Are you sponsoring any schedules in support of your Direct Testimony?

A5. Yes. My analysis and recommendations are supported by the data presented in Exhibit No. ___(CMW-2), Schedules 2 through 13, which were prepared by me or under my direction.

Q6. Please provide a brief overview of the analyses that led to your ROE recommendation.

A6. I have estimated the cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. My recommendation also takes into consideration: (1) the Company's small size relative to the proxy group; (2) flotation costs; (3) the Company's anticipated capital expenditure requirements; and (4) the Company's regulatory risk as compared with the proxy group. Finally, I considered the Company's capital structure as compared with the capital structures of the proxy companies. While I do not make specific adjustments to my ROE recommendation for these factors, I did consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

Q7. How is the remainder of your testimony organized?

A7. The remainder of my testimony is organized as follows:

- Section II provides a summary of my analyses and conclusions.
- Section III reviews the regulatory guidelines pertinent to the development of the cost of capital.
- Section IV discusses current and projected capital market conditions and the effect of those conditions the cost of equity.
- Section V explains my selection of the proxy group.
- Section VI describes my cost of equity estimates and the analytical basis for my recommendation of the appropriate ROE for Montana-Dakota.
- Section VII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.
- Section VIII provides an assessment of the reasonableness of the Company's proposed capital structure relative to the proxy group.
- Section IX presents my conclusions and recommendations.

II. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q8. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A8. In developing my recommended ROE for Montana-Dakota, I considered the following:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having

[1] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

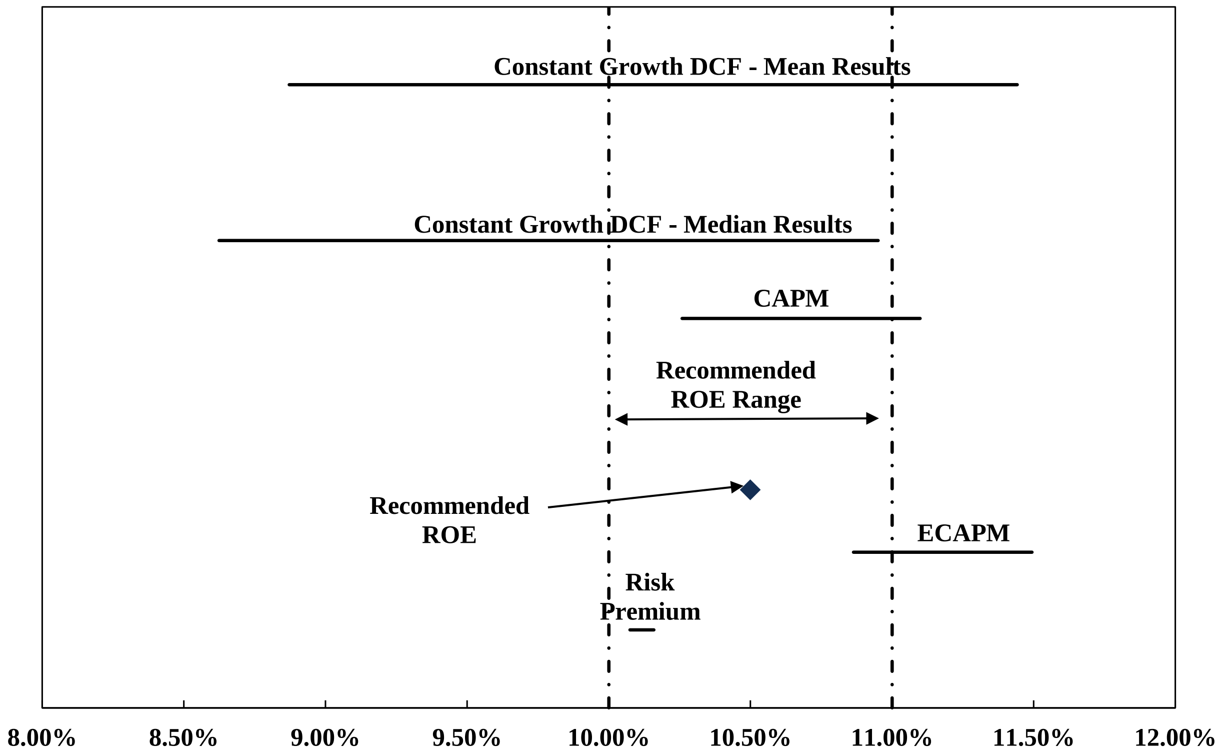
- The effect of current and projected capital market conditions on ROE estimation models and on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)
- Although the companies in my proxy group are generally comparable to Montana-Dakota, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q9. What are the results of the models that you have used to estimate the cost of equity for Montana-Dakota?

A9. Figure 1 summarizes the range of results produced by the constant growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses.[2]

[2] The cost of equity model results are also summarized in Exhibit No. ___ (CMW-2), Schedule 2.

Figure 1: Summary of Cost of Equity Model Results



As shown in Figure 1 (and Exhibit No. ___(CMW-2), Schedule 2), the range of results produced by the cost of equity estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies. As a result, my ROE recommendation considers the range of results of the Constant Growth DCF model, as well as the results of the CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses. My ROE recommendation also considers Montana-Dakota’s company-specific risk factors and current and prospective capital market conditions.

Q10. Why is it important to consider prospective capital market conditions in setting the ROE in this proceeding?

A10. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.
- Long-term interest rates have increased substantially in the past year and are expected to remain elevated at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, it is likely that utility share prices will decline.
- Rating agencies have responded to the risks of the utility sector, with Moody's Investors Service ("Moody's") most recently indicating its outlook for the industry in 2023 is "negative," citing factors such as interest rates and inflation that create pressure for customer affordability and prompt rate recovery.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.
- Consequently, the results of the DCF model, which relies on current utility share prices, may understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for Montana-Dakota.

Q11. What is your recommended ROE for Montana-Dakota in this proceeding?

A11. Considering the analytical results presented in Figure 1, current and prospective capital market conditions, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that an ROE in the range of 10.00 percent to 11.00 percent is reasonable, and within that range, I recommend an ROE of 10.50 percent.

Q12. Is the Company's requested capital structure reasonable?

A12. Yes. The Company's proposed equity ratio of 50.392 percent is well within the range of equity ratios for the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering the credit rating agencies concerns regarding the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and commodity costs, and the pressure that those factors place on customer affordability and utilities' prompt rate recovery.

III. REGULATORY GUIDELINES

Q13. Please describe the guiding principles to be used in establishing the cost of equity for a regulated utility.

A13. The United States Supreme Court's precedent-setting *Hope and Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

Q14. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A14. Yes. In Docket No. EL11-019 for Northern State Power Company, the Commission stated that:

> Determining a reasonable ROE rests primarily on sound judgment looking at the overall results of the analysis. Under SDCL 49-34A-8 and relevant

[3] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).

> case law, rates set in this proceeding must be just and reasonable. *Federal Power commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
>
> The just and reasonable test focuses on whether the "total effect of the rate order [is] unreasonable." *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989). Under the just and reasonable test "it is the result reached, not the method employed that is controlling" and "the impact of the rate order which counts." *Hope, supra*, at 602. The South Dakota Supreme Court recognized that rates that do not yield a fair return are unreasonable. *In Re Northwestern Bell*, 43 N.W.2d 553, 555 (S.D. 1950). The rate of a return must be "commensurate with returns on other investments of corresponding risks" and "be sufficient ... to attract capital." *Northwestern Public Service v. Cities of Chamberlain et al*, 265 N.W.2d 867, 873 (S.D. 1978).
>
> "The ratemaking process under the Act, i.e. the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests." *Hope, supra*, at 603. "Regulation may, consistently with the Constitution, limit stringently the return recovered on investment, for investors' interests provide only one of the variables in the constitutional calculus of reasonableness." *Permian Basin Area Rate Cases*, 390 U.S. 747, 769 (1968).[4]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for the Company, including the principle that an allowed rate of return must be sufficient to enable regulated companies like Montana-Dakota to attract capital on reasonable terms.

Q15. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A15. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek

---

[4] South Dakota Public Utilities Commission, Docket No. EL11-019, Final Decision and Order, July 2, 2012, at 4.

alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company’s ability to attract capital at reasonable cost.

Q16. Is a utility’s ability to attract capital also affected by the ROEs authorized for other utilities?

A16. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other electric, natural gas, and water utilities can inhibit the utility’s ability to attract capital for investment.

While Montana-Dakota is committed to investing the required capital to provide safe and reliable service, because Montana-Dakota is a subsidiary of MDU Resources, the Company competes with the other MDU Resources subsidiaries for discretionary investment capital. In determining how to allocate its finite discretionary capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q17. Is the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A17. Yes. The regulatory framework is one of the most important factors in debt and equity investors’ assessments of risk. Specifically regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing, they also act as a signal to equity investors about the risk of investing in the equity of a company.

Q18. What is the standard for setting the ROE in any jurisdiction?

A18. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for the Montana-Dakota's natural gas operations in South Dakota.

Q19. What are your conclusions regarding regulatory guidelines?

A19. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable opportunity to earn an

ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

IV. CAPITAL MARKET CONDITIONS

Q20. Why is it important to analyze capital market conditions?

A20. The models used to estimate the cost of equity rely on market data that are specific either to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses both current and projected market data, specifically stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE and the recommended ROE for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q21. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A21. The cost of equity for regulated utility companies is affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q22. What effect do current and prospective market conditions have on the cost of equity for Montana-Dakota?

A22. As is discussed in more detail in the remainder of this section, the combination of persistently high inflation and the Federal Reserve's changes in monetary policy contribute to an expectation of increased market risk and an increase in the cost of the investor-required return. These factors must be considered in setting a forward-looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased from the pandemic lows seen in 2020 in direct response to the Federal Reserve's monetary policy, are expected to remain at near current levels over the next year. Since there is a strong historical inverse correlation between interest rates (i.e., yields on long-term government bonds) and the share prices of utility stocks (i.e., share prices of utility stocks typically fall when interest rates rise and vice versa) and the yields on long-term government bonds currently exceed the dividend yields of utilities when historically long-term government bond yields have been lower than the dividend yields of utilities, it is reasonable to expect that utility investors' required return is increasing. Therefore, as explained in further detail below, cost of equity estimates based solely on current market conditions will understate the cost of equity required by investors during the future period that the Company's rates determined in this proceeding will be in effect.

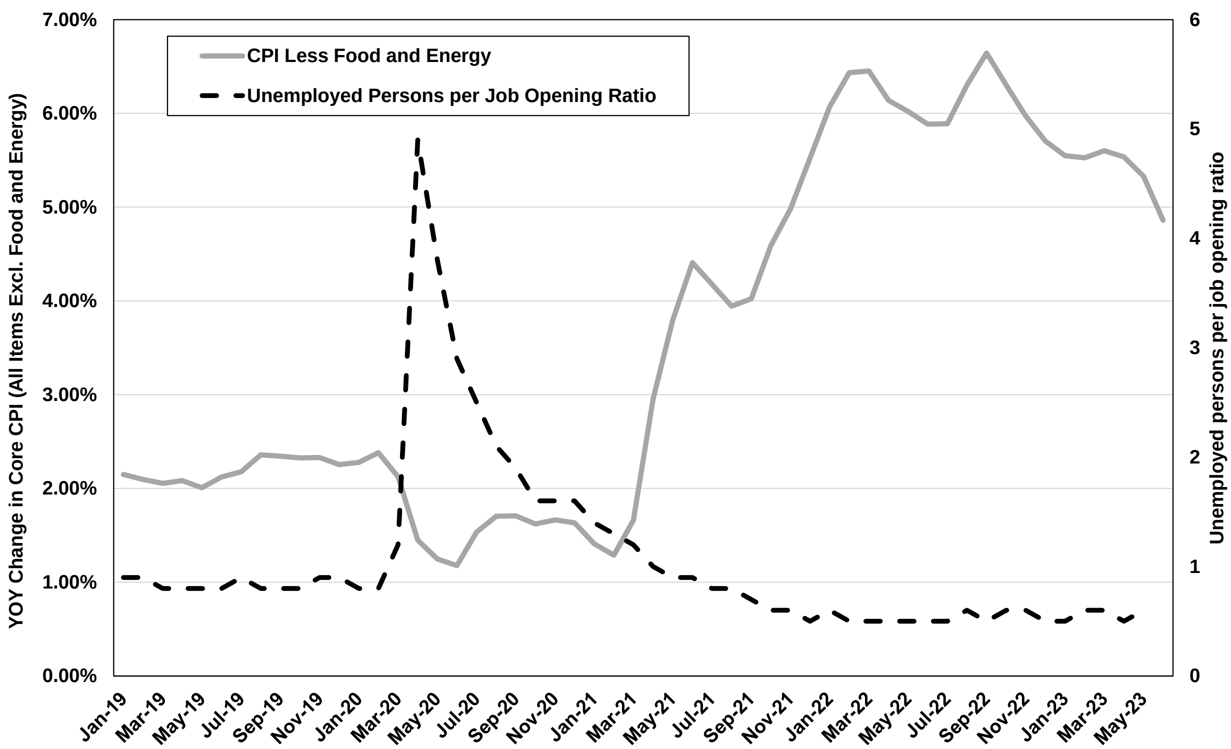
A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q23. Has inflation increased significantly over the past year?

A23. Yes. Figure 2 presents the year-over-year ("YOY") change in core inflation as measured by the Consumer Price Index ("CPI") excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve since it removes the effect of food and energy prices, which can be highly volatile. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982. Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, core inflation continues to remain above the Federal Reserve's target level of 2.0 percent.

Finally, as shown in Figure 2, I also considered the ratio of unemployed persons per job opening which is currently 0.6 and has been consistently below 1.0 since 2021 despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's duel mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to June 2023[5]



5 Bureau of Labor Statistics.

Q24. What are the expectations for inflation over the near-term?

A24. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level over at least the next year and that monetary policy will remain restrictive in order to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in July 2023 observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target and noted that further policy firming is possible including additional increases in the federal funds rate:

> So, I'll just say again, the broader picture of what we want to see is we want to see easing of supply constraints and normalization of pandemic related distortions to demand and supply, we want to see economic growth running at moderate or modest levels to help ease inflationary pressures, we want to see continued restoration of supply and demand balance, particularly in the labor market, and all of that should lead to declining inflationary pressures. What we see is we see those pieces of the puzzle coming together and we're seeing evidence of those things now, but I would say that what our eyes are telling us is that policy has not been restrictive enough for long enough to have its full desired effects. So we intend, again, to keep policy restrictive until we're confident that inflation is coming down sustainably to our 2 percent target, and we're prepared to further tighten if that is appropriate. And we think the process, you know, still probably has a long way to go.[6]

Chair Powell also continued to reiterate that "[r]educing inflation is likely to require a period of below-trend growth and some softening in labor market conditions."[7]

6 Federal Reserve, Transcript of Chair Powell's Press Conference, July 26, 2023, p 11.

7 Federal Reserve, Transcript of Chair Powell's Press Conference, July 26, 2023, p 3.

B. The Use of Monetary Policy to Address Inflation

Q25. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A25. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Since the March 2022 meeting, the Federal Reserve increased the target federal funds rate through a series of increases from 0.00 – 0.25 percent to 5.25 percent to 5.50 percent.[8] Further, as noted above, while the Federal Reserve acknowledges that inflation has declined from its peak, it still is well above the Federal Reserve's target of 2 percent. Therefore, the Federal Reserve anticipates the continued need to maintain the federal funds rate at a restrictive level in order to achieve its goal of 2 percent inflation over the long-run.

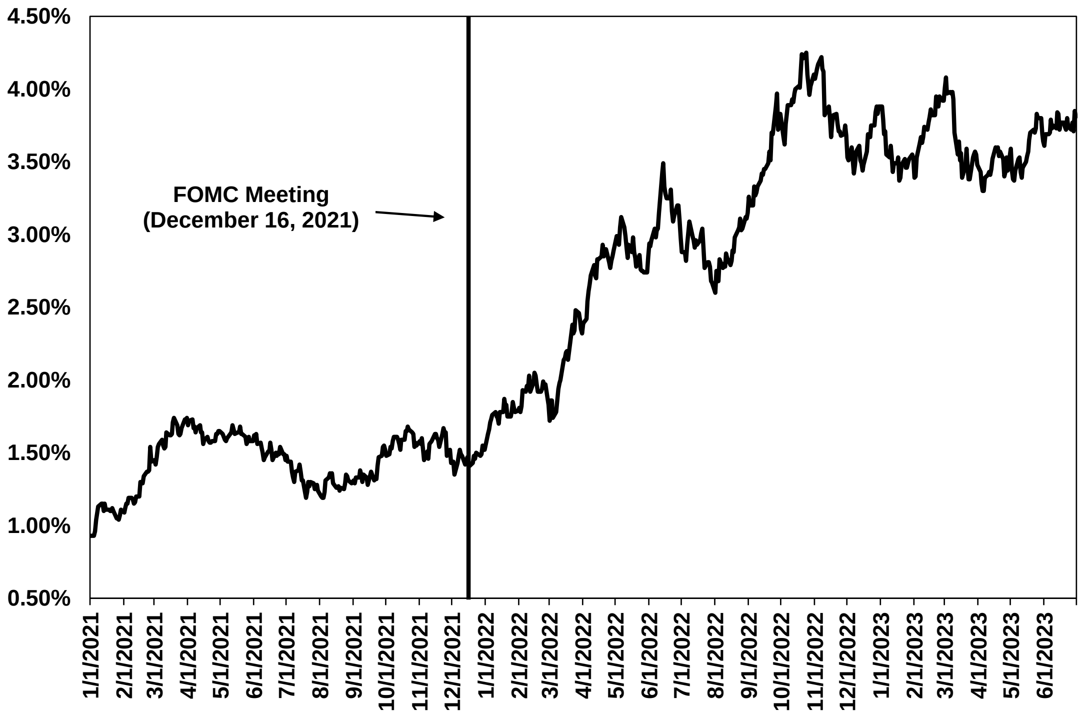
C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q26. How have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A26. As the Federal Reserve has substantially increased the federal funds rate in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rate have also increased. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has more than doubled, increasing from 1.47 percent on December 15, 2021 to 3.81 percent at the end of June 2023.

[8] Federal Reserve, Press Releases, March 16, 2022, May 4, 2022, June 15, 2022, September 22, 2022, November 2, 2022, February 1, 2023, March 22, 2023, May 3, 2023, July 26, 2023. Federal Reserve Board - Press Releases

Figure 3: 10-Year Treasury Bond Yield—Janaury 2021through June 30, 2023[9]



Q27. What have equity analysts said about long-term government bond yields?

A27. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the end of 2024. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.50 percent through the fourth quarter of 2024.[10] It is reasonable to expect that if government bond yields remain elevated the cost of equity will be increasing above the levels experienced in the 2020 and 2021 lower interest rate environment.

---

9 S&P Capital IQ Pro.

10 *Blue Chip Financial Forecasts*, Vol. 42, No. 7, June 30, 2023, p. 2.

Q28. How have interest rates and inflation changed since the Company's last rate case?

A28. As shown in Figure 4, when the Commission approved the settlement agreement in the Company's 2015 rate proceeding, interest rates (as measured by the 30-year Treasury bond yield) were 2.58 percent and core inflation was 2.26 percent. However, since the Company's last rate proceeding, long-term interest rates have increased by over 100 basis points, and inflation is significantly higher.

Figure 4: Change in Market Conditions Since Montana-Dakota's Last Rate Case[11]

Docket	Decision Date	Federal Funds Rate	30-Day Average of 30-Year Treasury Bond Yield	Core Inflation Rate
NG15-005	6/15/2016	0.37%	2.58%	2.26%
Current	6/30/2023	5.08%	3.89%	4.86%

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q29. Are utility share prices correlated to changes in the yields on long-term government bonds?

A29. Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships

[11] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[12]

Q30. How do equity analysts expect the utility sector to perform in an increasing interest rate environment?

A30. Equity analysts project that utilities will underperform the broader market given the increases in interest rates. Fidelity classifies the utility sector as underweight,[13] and Keybanc Capital Markets analyst Sophie Karp recently noted she had a negative view of the sector in 2023 and expects a decline in the relative valuation of the utilities sector as compared to the S&P 500:

> The utility sector's relative outperformance came on the back of the pre-recessionary environment in the U.S. in 2022, analyst Karp said. She noted that the sector now traded at a 2.8 times premium to the S&P 500 Index, which is relatively wide by historical standards.
>
> *She said the utility sector is relatively overvalued and will see a mean reversion in 2023,* adding that the last time such a premium over the S&P 500 Index happened was in 2004.
>
> *"We are therefore negative on the sector overall going into 2023 and our OW picks grow fewer,"* Karp said
>
> *There has been a surprising deterioration of the regulatory environment across multiple jurisdictions, including the historically stronger ones,* she noted. Some regulatory developments, according to the analyst, are driven by the regulator's desire to moderate the impact on customer bills. "Given that power and commodity prices remain elevated, we expect to continue seeing regulators getting 'creative' with assumptions and rate mechanisms to achieve that goal," she added.

---

[12] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

[13] Fidelity. "Third Quarter 2023 Investment Research Update." July 24, 2023.

> Karp said she would focus on rate affordability, as inflationary pressures will likely be a factor for the foreseeable future.
>
> "As we turn to 2023, we believe that the sector will find it difficult to defend this relative valuation position, particularly as macro headwinds persist and begin to take a toll on utility earnings," she added.[14]

Q31. Why do equity analysts expect the utility sector to underperform over the near-term?

A31. While interest rates have increased substantially over the past year, the valuations of utilities have remained elevated and have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through June 2023 ("yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds. As shown in Figure 5, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of June 30, 2023 was negative 0.53 percent. However, the long-term average yield spread from 2010 to 2023 is 1.30 percent. Therefore, the current yield spread is well below the long-term average.

For further context as to how unlikely it is to have a yield spread of negative 0.53 percent, I calculated the z-score for the current yield spread, which measures the number of standard deviations from the mean. The current yield spread of negative 0.53 percent has a z-score of -2.05, a yield spread of negative 0.53 percent is over 2 standard deviations from the

[14] Market Insider. "After A 'Good Run' For Utilities In 2022, Analyst Says 'Trade Is Over – For Now,' But Retains Bullish Bias On These Stocks", January 17, 2023. (emphasis added)

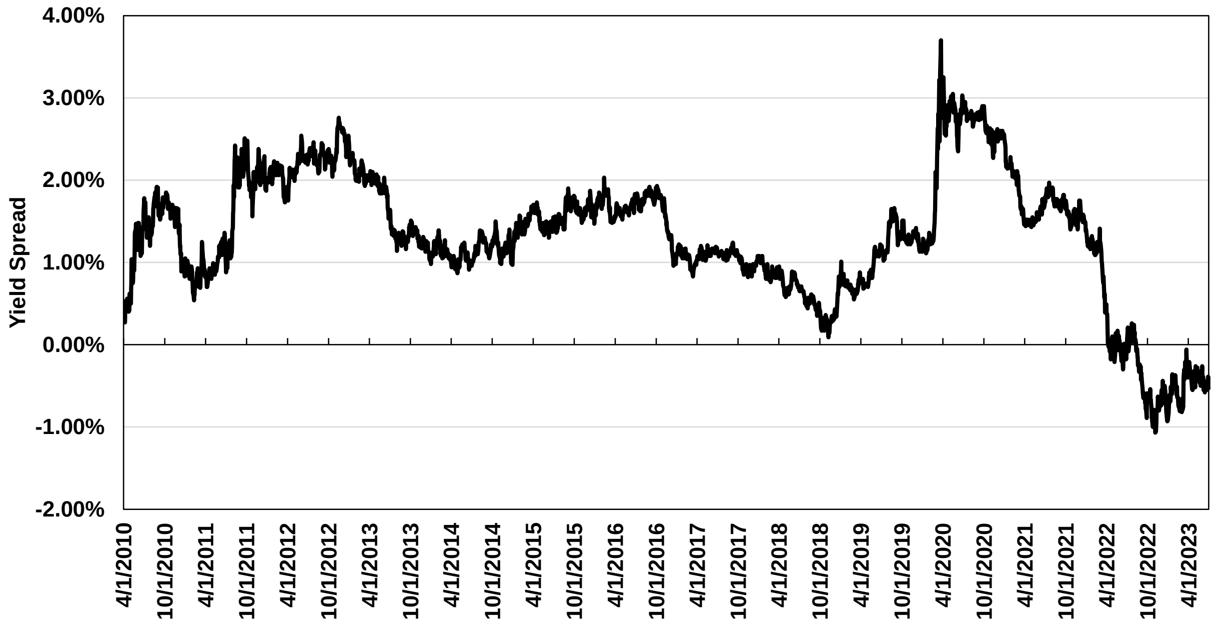
mean of 1.30 percent.[15] In other words, 95 percent of the daily yield spread observations from 2010 through June 2023 fall between -0.28 percent and 2.88 percent, with the current yield spread of negative 0.53 percent being outside of that range. Thus, the current yield spread is an outlier, which is why equity analysts do not expect this current level to hold.

Since long-term bond yields are expected to remain elevated at current levels over the near-term, equity analysts expect utilities to underperform, and thus the dividend yields for utilities will increase. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

---

[15] The z-score is calculated as: (yield spread at June 30, 2023 minus average yield spread 2010 through June 2023)/standard deviation of yield spread from 2010 through June 2023. This equals: (-0.53 minus 1.30)/0.0079.

Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – June 2023[16]



E. Conclusion

Q32. What are your conclusions regarding the effect of current market conditions on the cost of equity for the Company?

A32. Investors expect long-term interest rates to remain relatively high through 2024 in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already greater than utility stock dividend yields, the share prices of utilities are likely to continue to decline, which is the reason a number of equity analysts have classified the sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher

16 S&P Capital IQ Pro and Bloomberg Professional.

end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which more directly reflect changes in interest rates and the investor-required return on equity.

V. PROXY GROUP SELECTION

Q33. Please provide a brief profile of Montana-Dakota.

A33. Montana-Dakota Utilities Co. is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU"). MDU provides natural gas distribution service across eight states through the Company and its affiliates Cascade Natural Gas Corp. and Intermountain Gas Company. In total, MDU serves approximately 1.03 million natural gas customers. Specifically, the Company provides service to approximately 64,400 natural gas customers in South Dakota[17], and the Company's South Dakota natural gas operations accounted for approximately 6 percent of MDU's total retail gas sales revenue in 2022.[18] The Company also provides vertically-integrated electric utility service in South Dakota, North Dakota, Montana, and Wyoming, serving approximately 144,500 customers. Montana-Dakota Utilities Co. currently has an investment-grade long-term rating of BBB+ (Outlook: Developing) from S&P[19] and BBB+ (Outlook: Stable) from Fitch.[20]

---

[17] Company provided data.

[18] MDU Resources Group, Inc. Form 10-K for the fiscal year ended December 31,2022, at 15.

[19] Source: S&P Capital IQ Pro, (accessed July 14, 2023).

[20] Source: FitchRatings, (accessed July 14, 2023).

Q34. Why have you used a group of proxy companies to estimate the cost of equity for the Company?

A34. One of the purposes of this proceeding is to estimate the cost of equity for a utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and Montana-Dakota's operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the cost of equity estimation process.

Even if Montana-Dakota was a publicly traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for the Company.

Q35. How did you select the companies included in your proxy group?

A35. I began with the group of 10 publicly traded companies that *Value Line* classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends that have not been reduced in the last three years, since companies that do not pay dividends cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;

- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and,
- were not party to a merger or transformative transaction during the analytical period considered or had a material event that would have affected the market data for the company.

Q36. What is the composition of your proxy group?

A36. The screening criteria discussed above is shown in Exhibit No. ___ (CMW-2), Schedule 3, and resulted in a proxy group consisting of the companies shown Figure 6 below.

Figure 6: Natural Gas Utility Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
NiSource	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire, Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q37. Please briefly discuss the ROE in the context of the regulated rate of return.

A37. The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q38. How is the required cost of equity determined?

A38. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q39. What methods did you use to establish your recommended ROE in this proceeding ROE?

A39. I considered the results of the Constant Growth DCF model, the CAPM, the ECAPM, and the Risk Premium analyses. As discussed in more detail below, a reasonable ROE estimate considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q40. Is it important to use more than one analytical approach to estimate the cost of equity?

A40. Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and we use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[21] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[22] recommend the CAPM, DCF, and BYRP approaches.

Q41. Do current market conditions increase the importance of using more than one analytical approach?

A41. Yes. As discussed previously, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. The benefit of using multiple models is that each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. As discussed previously, the CAPM, ECAPM, and BYRP analyses offer some balance through the use of projected interest rates since the effect of changes in interest rates, particularly the recent increase in interest rates, may not be captured as well in the DCF model at this time. Therefore, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

---

[21] Copeland, Tom, Tim Koller and Jack Murrin. Valuation: Measuring and Managing the Value of Companies. New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

[22] Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

B. Constant Growth DCF Model

Q42. Please describe the DCF approach.

A42. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q43. What assumptions are required for the constant growth DCF model?

A43. The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

Q44. What market data did you use to calculate the dividend yield in your constant growth DCF model?

A44. The dividend yield in my constant growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended June 30, 2023.

Q45. Why did you use 30-, 90-, and 180-day averaging periods?

A45. I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q46. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A46. Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first-year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q47. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A47. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the constant growth DCF model.

Q48. Which sources of long-term earnings growth rates did you use?

A48. My constant growth DCF model incorporates three sources of long-term earnings per share ("EPS") growth rates: (1) *Zacks Investment Research* ("*Zacks*"); (2) Yahoo! Finance; and (3) *Value Line*.

Q49. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A49. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q50. How did you calculate the range of results for the constant growth DCF models?

A50. I calculated the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo Finance, and *Value Line* projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculated results using the average growth rate from all three sources for each proxy group company.

Q51. What were the results of your constant growth DCF analyses?

A51. Figure 7 (see also Exhibit No. ___ (CMW-2), Schedule 4) summarizes the results of my DCF analyses. As shown, the mean/median DCF results using the average growth rates range from 9.94 percent to 10.16 percent, and the mean/median results using the maximum growth rates range from 10.82 percent to 11.49 percent. While I also summarize the mean DCF results using the minimum growth rates, given the expected underperformance of utility stocks and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

Figure 7: Constant Growth Discounted Cash Flow Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean:			
30-Day Avg. Stock Price	8.92%	10.02%	11.49%
90-Day Avg. Stock Price	8.84%	9.94%	11.41%
180-Day Avg. Stock Price	8.85%	9.96%	11.42%
Average	8.87%	9.97%	11.44%
Median:			
30-Day Avg. Stock Price	8.75%	10.08%	11.13%
90-Day Avg. Stock Price	8.58%	10.12%	10.90%
180-Day Avg. Stock Price	8.55%	10.16%	10.82%
Average	8.62%	10.12%	10.95%

Q52. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of relatively high inflation and elevated interest rates?

A52. Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[23]
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of

[23] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

> reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[24]

Q53. What are your conclusions about the results of the DCF models?

A53. As discussed previously, one primary assumption of the DCF model is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF model with caution. Therefore, while I have given weight to the results of the DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

C. CAPM Analysis

Q54. Please briefly describe the CAPM.

A54. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, systematic risk of that security. Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

The CAPM is defined by four components:

---

[24] *Id*., pp. 177–178.

$$K_e = r_f + \beta(r_m \text{-} r_f) \quad [3]$$

Where:

K_e = the required market cost of equity;
β = beta coefficient of an individual security;
r_f = the risk-free rate of return; and
r_m = the required return on the market.

In this specification, the term ($r_m - r_f$) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined a:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q55. What risk-free rate do you use in your CAPM analysis?

A55. I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds, which is 3.89 percent;[25] (2) the average projected 30-year Treasury bond yield for the fourth quarter of 2023 through the fourth quarter of 2024, which

[25] Bloomberg Professional as of June 30, 2023.

is 3.84 percent;[26] and (3) the average projected 30-year Treasury bond yield for 2025 through 2029, which is 3.80 percent.[27]

Q56. What beta coefficients do you use in your CAPM analysis?

A56. As shown Exhibit No. ___(CMW-2), Schedule 5, I use the beta coefficients for the proxy group companies as reported by Bloomberg and *Value Line*. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The *Value Line* beta coefficients are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Additionally, as shown in shown Exhibit No. ___(CMW-2), Schedule 5, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group. As shown in Exhibit No. ___ (CMW-2), Schedule 6, the long-term average utility Beta coefficient was calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2022.

Q57. How do you estimate the market risk premium in the CAPM?

A57. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit No. ___(CMW-2), Schedule 7, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.64 percent and a weighted long-term growth rate of 10.95 percent, the estimated required market return for the S&P 500 Index

---

[26] *Blue Chip Financial Forecasts*, Vol. 42, No. 7, June 30, 2023, at 2.

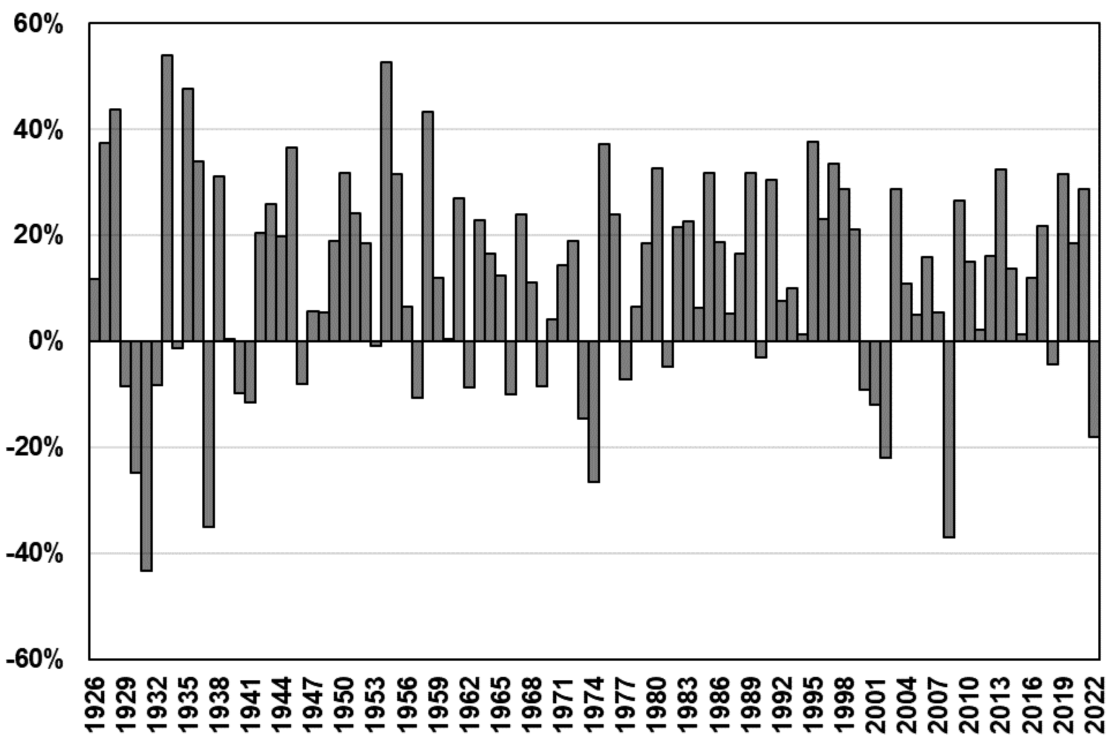
[27] *Blue Chip Financial Forecasts*, Vol. 42, No. 6, June 1, 2023, at 14.

as of June 30, 2023 is 12.68 percent. Based on the three risk-free rates considered, the market risk premium ranges from 8.79 percent to 8.88 percent.

Q58. How does the current expected market return compare to observed historical market returns?

A58. As shown in Figure 8, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.68 percent is not unreasonable. In 50 out of the past 97 years (or approximately 52 percent of observations), the realized equity market return was at least 12.68 percent or greater**.**

Figure 8: Realized U.S. equity market returns (1926-2022)[28]



---

28 Depicts total annual returns on large company stocks, as reported in the 2023 *Kroll* SBBI Yearbook.

Q59. Did you consider another form of the CAPM in your analysis?

A59. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[29] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

Where:
k_e = the required market cost of equity;
β = Adjusted beta coefficient of an individual security;
rf = the risk-free rate of return; and
r_m = the required return on the market as a whole.

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[30]

---

[29] *See, e.g.*, Morin, Roger A. New Regulatory Finance. Public Utilities Reports, Inc., 2006, at 189.
[30] *Id*. at 191.

Consistent with my CAPM, my application of the ECAPM uses the same three yields on the 30-year Treasury bonds as the risk-free rate, forward-looking market risk premium estimates, and beta coefficients.

Q60. What are the results of your CAPM analyses?

A60. As shown in Figure 9 (see also Exhibit No. ___(CMW-2), Schedule 5), my traditional CAPM analysis produces a range of returns from 10.26 percent to 11.10 percent. The ECAPM analysis results range from 10.86 percent to 11.49 percent.

Figure 9: CAPM and ECAPM Results

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.10%	11.09%	11.08%
Current Bloomberg Beta	10.58%	10.57%	10.56%
Long-term Avg. *Value Line* Beta	10.28%	10.27%	10.26%
ECAPM:			
Current *Value Line* Beta	11.49%	11.49%	11.48%
Current Bloomberg Beta	11.11%	11.10%	11.09%
Long-term Avg. *Value Line* Beta	10.88%	10.87%	10.86%

D. BYRP Analysis

Q61. Please describe the BYRP analysis.

A61. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for natural gas utilities as the historical measure of the cost of equity to determine the risk premium.

Q62. What is the fundamental relationship between the equity risk premium and interest rates?

A62. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. The analysis provided in Exhibit No. ___(CMW-2), Schedule 8 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[31]

Q63. Is the BYRP analysis relevant to investors?

A63. Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my BYRP analysis is based on authorized

---

31 *See e.g.*, Berry, S. Keith. "Interest Rate Risk and Utility Risk Premia during 1982-93." Managerial and Decision Economics, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q64. What did your BYRP analysis reveal?

A64. As shown in Figure 10, from 1992 through June 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

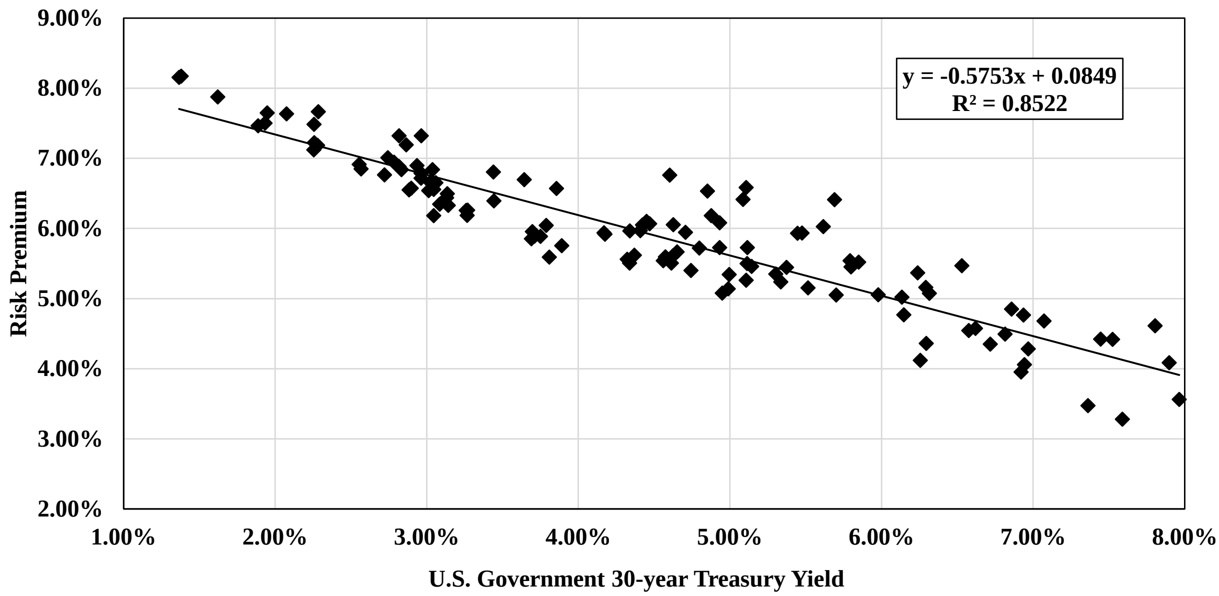
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding authorized ROEs were derived from all natural gas utility rate cases from 1992 through June 2023 as reported by Regulatory Research Associates ("RRA").[32] This equation's coefficients were statistically significant at the 99.00 percent level.

[32] This analysis was screened to eliminate limited issue rider cases and cases that were silent with respect to the authorized ROE.

Figure 10: Risk Premium Regression Analysis



Q65. What are the results of your BYRP analysis?

A65. The results of my BYRP analysis are shown in Figure 11 (and on Exhibit No. ___(CMW-2), Schedule 8).

Figure 11: Risk Premium Results

	30-Year Treasury Bond Yield	Risk Premium	Cost of Equity
Current Risk-Free Rate	3.89%	6.25%	10.14%
Near-Term Projected Risk-Free Rate	3.84%	6.28%	10.12%
Longer-Term Projected Risk-Free Rate	3.80%	6.31%	10.11%
Average			10.12%

Q66. How did the results of the BYRP analysis inform your recommended ROE for the Company?

A66. I have considered the results of the BYRP analysis in setting my recommended ROE for Montana-Dakota's natural gas operations in South Dakota. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VII. REGULATORY AND BUSINESS RISKS

Q67. Taken alone, do the results of the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Company?

A67. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size Risk

Q68. Is there a risk to a firm associated with small size?

A68. Yes. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[33]

---

[33] Annin, Michael. "Equity and the Small-Stock Effect." Public Utilities Fortnightly, October 15, 1995.

Q69. How does the smaller size of a utility affect its business risk?

A69. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q70. How do Montana-Dakota's natural gas operations in South Dakota compare in size to the proxy group companies?

A70. Montana-Dakota's natural gas operations in South Dakota are substantially smaller than the median for the proxy group companies in terms of market capitalization. While Montana-Dakota is not publicly traded on a stand-alone basis, as shown on Exhibit No. ___(CMW-2), Schedule 9, I have estimated the implied market capitalization for the Company (*i.e.*, the market capitalization if the Company were a stand-alone publicly-traded entity) relative to the actual market capitalization for the proxy group companies.

Specifically, to estimate the size of the Company's implied market capitalization relative to the proxy group, I first calculated the equity component of the Company's capital structure by multiplying the Company's test year rate base of $77.1 million by the Company's proposed common equity ratio in this proceeding of 50.39 percent. I then applied the median market-to-book ratio for the proxy group of 1.64 to the Company's implied common equity balance to estimate an implied market capitalization, which is approximately $63.8 million, or just 1.45 percent of the median market capitalization for the proxy group.

Q71. How did you estimate the size premium for Montana-Dakota?

A71. Given this relative size information, it is possible to estimate the impact of size on the cost of equity for the Company using *Kroll* Cost of Capital Navigator data that estimates the stock risk premia based on the size of a company's market capitalization.[34] As shown on Exhibit No. ___(CMW-2), Schedule 9, the median market capitalization of the proxy group is approximately $4.41 billion, which corresponds to the fourth decile of *Kroll's* market capitalization data.[35] Based on *Kroll's* analysis, that decile corresponds to a size premium of 0.58 percent (*i.e.*, 58 basis points). In comparison, the Company's implied market capitalization of approximately $63.8 million falls within the tenth decile, which corresponds to a size premium of 4.83 percent (*i.e.*, 483 basis points). The difference between the size premium for the Company and the size premium for the proxy group is 425 basis points (*i.e.*, 4.83 percent minus 0.58 percent)

Q72. Were utility companies included in the size premium study conducted by *Kroll*?

A72. Yes. As shown in Exhibit 7.2 of the *Kroll* (formerly *Duff & Phelps*) 2019 Valuation Handbook, OGE Energy Corp. had the largest market capitalization of the companies

[34] *Kroll* Cost of Capital Navigator – Size Premium; annual data as of December 31, 2022.

[35] *Id.*

contained in the fourth decile, which indicates that Kroll has included utility companies in its size risk premium study.[36]

Q73. Is the size premium applicable to companies in regulated industries such as utilities?

A73. Yes. For example, Zepp (2003) provided the results of two studies that showed evidence of the required risk premium for small water utilities. The first study, which was conducted by the Staff of the California Public Utilities Commission, computed proxies for beta risk using accounting data from 1981 through 1991 for 58 water utilities and concluded that smaller water utilities had greater risk and required higher returns on equity than larger water utilities.[37] The second study examined the differences in required returns over the period of 1987 through 1997 for two large and two small water utilities in California. As Zepp (2003) showed, the required return for the two small water utilities calculated using the DCF model was on average 99 basis points higher than the two larger water utilities.[38]

Additionally, Chrétien and Coggins (2011) studied the CAPM and its ability to estimate the risk premium for the utility industry, and in particular subgroups of utilities.[39] The article considered the CAPM, the Fama-French three-factor model, and a model similar to the ECAPM, which as previously discussed, I have also considered in estimating the cost of equity for the Company. In the study, the Fama-French three-factor model explicitly included an adjustment to the CAPM for risk associated with size. As Chrétien and

---

36 *Kroll*. Valuation Handbook: Guide to Cost of Capital. 2019, Exhibit 7.2.

37 Zepp, Thomas M. "Utility Stocks and the Size Effect—Revisited." The Quarterly Review of Economics and Finance, Vol. 43, No. 3, 2003, at 578–582.

38 *Id*.

39 Chrétien, Stéphane, and Frank Coggins. "Cost Of Equity For Energy Utilities: Beyond The CAPM." Energy Studies Review, Vol. 18, No. 2, 2011.

Coggins (2011) show, the beta coefficient on the size variable for the U.S. natural gas utility group was positive and statistically significant indicating that small size risk was relevant for regulated natural gas utilities.[40]

Q74. Have regulators in other jurisdictions made a specific risk adjustment to the cost of equity results based on a company's small size?

A74. Yes. For example, in Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[41] Thus, the RCA awarded AEL&P an ROE of 12.875 percent, which was 108 basis points above the highest cost of equity estimate from any model presented in the case.[42] Similarly, the RCA has also noted that small size, as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions, increased the risk of ENSTAR Natural Gas Company.[43] Ultimately, the RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying

---

[40] *Id.*

[41] Regulatory Commission of Alaska, Docket No. U-10-29, Order No. 15, September 2, 2011, at 37.

[42] *Id.*, at 32 and 37.

[43] Regulatory Commission of Alaska, Docket No. U-16-066, Order No. 19, September 22, 2017, at 50-52.

> our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[44]

Additionally, the Minnesota Public Utilities Commission ("Minnesota PUC") authorized an ROE for Otter Tail Power Company ("Otter Tail") above the mean DCF results as a result of multiple factors, including Otter Tail's small size. The Minnesota PUC stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments.[45]

Finally, in Opinion Nos. 569 and 569-A, the Federal Energy Regulatory Commission ("FERC") adopted a size premium adjustment in its CAPM estimates for electric utilities. In those decisions, the FERC noted that "the size adjustment was necessary to correct for the CAPM's inability to fully account for the impact of firm size when determining the cost of equity."[46]

Q75. How have you considered the smaller size of Montana-Dakota's natural gas distribution operations in South Dakota in your recommended ROE?

A75. While I have estimated the effect of the Company's small size of its natural gas operations in South Dakota on the cost of equity, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of the Company's utility

---

44 *Id.*

45 Minnesota Public Utilities Commission, Docket No. E017/GR-15-1033, Order, August 16, 2016, at 55.

46 *Ass'n. of Businesses Advocating Tariff Equity, et. al., v. Midcontinent Indep. Sys. Operator, Inc., et. al.*, 171 FERC ¶ 61,154 (2020), at ¶ 75. The U.S. Court of Appeals recently vacated FERC Order No. 569 decisions that related to its risk premium model and remanded the case to FERC to reopen the proceedings. However, in its decision, the Court did not reject FERC's inclusion of the size premium to estimate the CAPM. (*See*, United States Court of Appeals Case No. 16-1325, Decision No. 16-1325, August 9, 2022 at 20).

operations in the determination of where, within the range of analytical results, Montana-Dakota's required cost of equity falls. All else equal, the additional risk associated with the Company's small size supports an ROE toward the upper end of the range of results from the cost of equity estimation models.

B. Flotation Cost

Q76. What are flotation costs?

A76. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q77. Why is it important to consider flotation costs in the authorized ROE?

A77. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q78. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A78. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation costs are incurred prior to the test year but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, it is irrelevant whether an issuance occurs during the test year or is planned for the test year because failure to allow recovery of past flotation costs may deny the Company the opportunity to earn its required rate of return in the future.

Q79. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A79. Assume MDU issues stock with a value of $100, and an equity investor invests $100 in MDU in exchange for that stock. Further, suppose that after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q80. Is the date of MDU's last issuance of common equity important in the determination of flotation costs?

A80. No. As shown in Exhibit No. ___(CMW-2), Schedule 10, MDU closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that he should have a reasonable opportunity to earn a return on the full amount of capital that he has contributed. Returning to my earlier example, the investor who contributed

$100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q81. Is the need to consider flotation costs eliminated because Montana-Dakota is a wholly-owned subsidiary of MDU?

A81. No, it is not. Although the Company is a wholly-owned subsidiary of MDU, it is appropriate to consider flotation costs. Wholly-owned subsidiaries receive equity capital from their parent and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based upon the returns of those subsidiaries. To deny recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately penalizes the investors that fund utility operations and inhibits the utility's ability to obtain new equity capital at a reasonable cost. This is particularly important in the current circumstance given that the Company is planning significant capital expenditures in the near term.

Q82. Is the need to consider flotation costs recognized by the academic and financial communities?

A82. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[47]

Q83. Has the Commission found that flotation cost adjustments for the recovery of equity issuance costs are appropriate?

A83. Yes, it has. The Commission has allowed flotation costs in recent cases. For example, the Commission determined that the recovery of flotation costs was appropriate in both its 2012 decision for Northern State Power Company[48] and its 2019 decision for Otter Tail Power Company.[49]

Q84. Have you estimated what a reasonable flotation cost adjustment would be for Montana-Dakota?

A84. Yes. My flotation cost is estimated on the costs of issuing equity that were incurred by MDU in its two most recent common equity issuances. As shown in Exhibit No. ___ CMW-2), Schedule 10, based on the flotation costs of those two issuances, the impact on the proxy group's cost of equity amounts to 10 basis points (i.e., 0.10 percent) based on the median and 15 basis points (i.e., 0.15 percent) based on the mean.

---

[47] Pratt, Shannon P. Cost of Capital Estimation and Applications. Second Edition, at 220-21.

[48] Docket No. EL11-019, The Mater of the Application of Northern States Power Company DBA Xcel Energy for Authority to Increase its Electric Rates, Final Decision and Order, (Jul. 2, 2012), at 6.

[49] Docket No. EL18-021, In The Mater of the Application of Otter Tail Power Company for Authority to Increase its Electric Rates, Final Decision and Order, (May 30, 2019), at 8.

Q85. Do your final cost of equity model results include an adjustment for flotation cost recovery?

A85. No, I did not make an explicit adjustment for flotation costs to any of the quantitative results of my cost of equity models. Rather, the incremental cost associated with stock issuance supports my recommended ROE.

C. Capital Expenditures

Q86. Please summarize the capital expenditure requirements for Montana-Dakota's natural gas distribution operations in South Dakota.

A86. As of December 31, 2022, the Company had net utility plant of approximately $68.19 million, and the Company currently projects capital expenditures for 2024 through 2027 of approximately $63 million.[50] Therefore, the Company's projected capital expenditures represent approximately 92 percent of its net utility plant as of December 31, 2022.

Q87. How is the Company's risk profile affected by its capital expenditure requirements?

A87. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

---

[50] Data provided by the Company.

Q88. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A88. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[51]

Therefore, to the extent that Montana-Dakota's rates do not permit the Company to recover its capital investments on a timely basis and provide a reasonable opportunity to earn its authorized return, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q89. How do Montana-Dakota's capital expenditure requirements compare to those of the proxy group companies?

A89. As shown in Exhibit No. ___(CMW-2), Schedule 11, I calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the

[51] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2027 by its total net utility plant as of December 31, 2022. As shown in Exhibit No. ___(CMW-2), Schedule 11, the Company's ratio of capital expenditures as a percentage of net utility plant is 91.96 percent, which is greater than the median for the proxy group companies of 50.87 percent. This result indicates a risk level for Montana-Dakota that is higher than the proxy group companies.

Q90. Does Montana-Dakota have a capital tracking mechanism to recover the costs associated with its capital expenditures between rate cases?

A90. No. Montana-Dakota currently has not requested approval to recover capital investment costs between rate cases utilizing a capital tracking mechanism. Therefore, Montana-Dakota depends entirely on rate case filings for capital cost recovery. However, significant programs like Montana-Dakota's that drive capital expenditure requirements generally receive cost recovery through infrastructure and capital trackers. As shown in Exhibit No.___(CMW-2), Schedule 12, 71.40 percent of the companies in the proxy group have some form of capital cost recovery mechanisms in place. Since Montana-Dakota does not currently have a capital tracking mechanism, Montana-Dakota's risk relative to the proxy group is significantly increased.

Q91. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A91. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, unlike a number of the operating subsidiaries of the proxy group, Montana-Dakota does not have a comprehensive capital tracking mechanism to recover the Company's projected capital expenditures.

Therefore, Montana-Dakota's capital expenditures plan and limited ability to recover the capital investment on an as incurred basis results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

D. Regulatory Risk

Q92. How does the regulatory environment affect investors' risk assessments?

A92. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover invested capital and the market-required return on such capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, which balances the long-term interests of investors and customers. In that respect, the regulatory framework in which a utility operates is one of the most important factors considered in both debt and equity investors' risk assessments.

Because investors have many investment alternatives, even within a given market sector, the Company's authorized returns must be adequate on a relative basis to ensure their ability to attract capital under a variety of economic and financial market conditions. From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet their near-term financial obligations, make the capital investments needed to maintain and expand their systems, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also from efficient access to capital markets.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (that is, debt interest must be paid prior to any equity dividends), equity investors are particularly concerned with the regulatory framework in which a utility operates and its effect on future earnings and cash flows.

Q93. How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A93. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[52]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[53] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2)

---

[52] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[53] Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[54]

Q94. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A94. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[55] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[56]

Q95. Have you conducted an analysis to compare the cost recovery mechanisms of Montana-Dakota to the cost recovery mechanisms approved in the jurisdictions in which the companies in your proxy group operate?

A95. Yes. I have evaluated the regulatory framework in South Dakota on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (i.e., forecast vs. historical); (2) use of rate design

---

[54] *Id.*, at 1.

[55] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.

[56] *Id.*

or other mechanisms that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No. ___(CMW-2), Schedule 12 and are summarized as follows:

> Test Year Convention: Montana-Dakota is relying on a partially forecasted test year in South Dakota for the period January 1, 2023 through December 31, 2023. Similarly, approximately 52 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a forecasted test year.

> Revenue Stabilization / Volumetric Risk: The Company does have a weather normalization clause known as the Distribution Delivery Stabilization Mechanism ("DDSM") to mitigate volumetric risk in South Dakota. The DDSM provides for the under/over recovery due to weather fluctuations during the period October 1 through April 30 each year. This is consistent with the proxy group as approximately 90 percent of the operating utility subsidiaries of the proxy group companies have some form of revenue stabilization either through revenue decoupling or rate design mechanisms.

> Capital Cost Recovery: As noted, the Company does not have a capital tracking mechanism to recover capital investment costs between rate cases. However, approximately 71 percent the operating utility subsidiaries of the proxy group companies have some form of capital cost recovery allowing for the recovery of capital investments placed into service between rate cases.

Q96. What is the effect on Montana-Dakota of having relatively fewer timely cost recovery mechanisms?

A96. The lack of timely cost recovery mechanisms can result in regulatory lag. Regulatory lag occurs when a regulated utility is not able to recover its just and reasonable costs of providing service to customers on a timely basis. Regulatory lag is reflected in a utility's financial performance through earnings attrition, which is the inability of the utility to earn its authorized ROE due to delays in the recovery of allowable costs that have been incurred to provide regulated service to customers.

Q97. What is your conclusion regarding the regulatory framework in South Dakota as compared with the jurisdictions in which the proxy group companies operate?

A97. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery through forecasted test years, capital cost recovery trackers and revenue stabilization mechanisms than Montana-Dakota has in South Dakota. As a result, I conclude that the Company has greater than average regulatory risk when compared to the proxy group.

VIII. CAPITAL STRUCTURE

Q98. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A98. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as Montana-Dakota. All else equal, a higher debt ratio increases the risk to equity investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q99. What is Montana-Dakota's proposed capital structure?

A99. The Company is proposing to establish a capital structure consisting of 50.392 percent common equity, 44.340 percent long-term debt and 5.268 percent short-term debt.

Q100. Did you conduct an analysis to assess the reasonableness of the requested equity ratio?

A100. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the equity ratios for the Company.

Specifically, I calculated the average proportion of common equity, long-term debt, preferred equity and short-term debt for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown on Exhibit No. ___(CMW-2), Schedule 13, the average common equity ratio for the operating subsidiaries of the proxy group companies ranged from 44.57 percent to 59.79 percent, with an average of 53.59 percent. Given that Montana-Dakota's proposed equity ratio of 50.392 percent is within the range of equity ratios for the utility operating subsidiaries of the proxy group companies, and in fact is below the average, I consider its proposed equity ratio to be reasonable.

Q101. Are there other factors to be considered in setting the Company's capital structure?

A101. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the outlook for utilities in 2023.

For example, Moody's recently revised its 2023 outlook for the regulated gas and electric utilities sector to "negative" based on ongoing challenges of inflation, increasing interest rates and higher natural gas prices. Moody's noted that these challenges increase the pressure on customer affordability, and thus face heightened public scrutiny and the ability of utilities to promptly recover their costs. Moody's concluded that regulated utilities' financial metrics are already under pressure with little cushion, and that sustained capital spending is likely as utilities continue progress towards emissions reductions and net-zero goals. Moody's noted that the outlook could return to stable if regulatory support remains intact, natural gas prices are at a level where utilities are able to recover their fuel and purchased power costs without delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or utilities' aggregate funds from operations-to-debt ratio remains between 14 and 15 percent.[57] While Moody's recently noted that natural gas prices have declined[58], inflation and interest rates remain elevated.

Fitch also highlights similar factors identified by Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that some offset in managing

57 Moody's Investors Service, Outlook. "2023 outlook negative due to higher prices, inflation and rising interest rates." November 10, 2022; Moody's Investors Service. Outlook, Sector In-Depth. "Inflation, high natural gas prices complicate prospects for supportive rate increases." November 11, 2022.

58 Moody's Investors Service, Sector Comment. "Regulatory risk related to service affordability eases as natural gas prices decline." March 9, 2023.

these headwinds include "higher authorized ROEs and the use of tools such as securitization of under-recovered fuel balances."[59]

Likewise, while S&P recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[60]

The credit ratings agencies' continued concerns over the negative effects of inflation, higher interest rates, and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for Montana-Dakota in the context of this proceeding

IX. CONCLUSIONS AND RECOMMENDATION

Q102. What is your conclusion regarding a fair ROE for the Company?

A102. Based on the various quantitative analyses summarized in Figure 12 and the qualitative analyses presented in my Direct Testimony, a reasonable range of ROE results for Montana-Dakota is from 10.00 percent to 11.00 percent. Within that range, I believe that

59 Fitch Ratings. "North American Utilities, Power & Gas Outlook 2023." December 7, 2022, at 1-2.

60 S&P Global Ratings. "The Outlook for North American Regulated Utilities Turns Stable," May 18, 2023, at 8.

an ROE of 10.50 percent is reasonable and appropriate. The recommended ROE takes into consideration the current conditions in capital markets including the high interest rates, and elevated inflationary pressures, both of which increase the cost of capital as well as the relative business and financial risk of Montana-Dakota as compared to the proxy group. This ROE would fairly balance the interests of customers and shareholders.

Figure 12: Summary of Results

Constant Growth DCF - Earnings Growth			
	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean:			
30-Day Avg. Stock Price	8.92%	10.02%	11.49%
90-Day Avg. Stock Price	8.84%	9.94%	11.41%
180-Day Avg. Stock Price	8.85%	9.96%	11.42%
Average	8.87%	9.97%	11.44%
Median:			
30-Day Avg. Stock Price	8.75%	10.08%	11.13%
90-Day Avg. Stock Price	8.58%	10.12%	10.90%
180-Day Avg. Stock Price	8.55%	10.16%	10.82%
Average	8.62%	10.12%	10.95%
CAPM, ECAPM, and Bond Yield Risk Premium			
	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.10%	11.09%	11.08%
Current Bloomberg Beta	10.58%	10.57%	10.56%
Long-term Avg. *Value Line* Beta	10.28%	10.27%	10.26%
ECAPM:			
Current *Value Line* Beta	11.49%	11.49%	11.48%
Current Bloomberg Beta	11.11%	11.10%	11.09%
Long-term Avg. *Value Line* Beta	10.88%	10.87%	10.86%
Bond Yield Risk Premium:	10.14%	10.12%	10.11%

Q103. What is your conclusion regarding the Company's proposed capital structure?

A103. My conclusion is that Montana-Dakota's proposal to establish a capital structure for ratemaking purposes consisting of 50.392 percent common equity, 44.340 percent long-term debt, and 5.268 percent short-term debt is reasonable when compared to the capital structures of the utility operating subsidiaries of the proxy group companies and taking in consideration the effect of inflation and increased capital expenditures on the cash flows, and therefore should be adopted.

Q104. Does this conclude your direct testimony?

A104. Yes, it does.

Christopher Wall

SENIOR ASSOCIATE

Boston +1.508.450.7361 Chris.Wall@brattle.com

With more than 10 years of experience as a financial and economic consultant in the energy industry, Mr. Wall specializes in regulatory economics for the electric, natural gas, and water utility sectors.

Mr. Wall has expertise in matters related to rate of return, cost of equity, capital structure, cost of service, and rate design. He has prepared expert testimony related to return on equity and capital structure in over 100 regulatory proceedings for electric, natural gas, and water utility clients across the US.

Mr. Wall has also applied his economics, financial modeling, advanced statistics, and econometrics competencies to prepare rate design, rate consolidation, marginal cost, cost of service, valuation, and demand forecast studies for electric and natural gas utilities. These studies have been submitted in utility regulatory proceedings throughout North America.

Mr. Wall has provided expert testimony before regulatory commissions in Arkansas, Massachusetts, New Hampshire and New York on issues that include cost of capital, natural gas demand forecasting, and statistical concepts for return on equity and cost of service.

Prior to joining Brattle, Mr. Wall was an Assistant Vice President at an economic consulting firm.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates

EDUCATION

- **Northeastern University**
  MA in Economics
- **Saint Peter's College**
  BA in Economics and Mathematics (summa cum laude)

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Senior Associate
- **Concentric Energy Advisors, Inc. (2010–2021)**
  Assistant Vice President (2021)
  Senior Project Manager (2019–2020)
  Project Manager (2017–2018)
  Senior Consultant (2015–2016)
  Consultant (2013–2014)
  Assistant Consultant (2011–2012)
  Associate (2010)

SELECTED CONSULTING EXPERIENCE

COST OF CAPITAL

- Provided expert testimony on the cost of capital for a Northeast natural gas utility, Northeast electric utility and Northeast water utility.
- Prepared expert testimony and exhibits for return on equity, capital structure, and cost of debt analysis for numerous electric, gas, and water utility clients across the US. This included preparing direct testimony, responding to data requests, drafting rebuttal testimony in response to intervening witnesses, assisting with hearing preparation, and drafting and reviewing post-hearing briefs.

DEMAND FORECASTING & SUPPLY PLANNING

- Filed expert testimony regarding the development of the natural gas demand forecast for a Northeast gas utility.
- Contributed to and worked on demand forecasting projects for multiple Northeast gas utilities:
  - Assisted in the development of natural gas price and effective degree day forecasts.
  - Developed natural gas demand forecasts by customer class using SPSS.
    - Developed models for number of customers and use per customer.

    - Performed checks for model stability, heteroscedasticity, and autocorrelation by performing the Chow, Breusch-Pagan, and Autocorrelation Function/Partial Autocorrelation Function tests.
  - Contributed in the development of the forecasting and supply planning report and supported data requests.

RATEMAKING

- Evaluated rate design restructuring and its impacts on customer bills for Northeast gas and electric utilities.
- Developed marginal cost studies and prepared testimony for Northeast electric and gas utilities.
- Designed rates and prepared testimony for a Northeast electric and gas utility.
- Prepared a cost of service study and designed rates for a Mid-Atlantic municipal gas utility.
- Prepared cost of service studies and designed rates for Midwest electric and gas utilities.
- Evaluated the impact of different rate alternatives and solar generation compensation approaches on solar customers in each rate class for a Midwest municipal electric utility.
- Contributed to the development of a benchmarking study to compare a Canadian natural gas utility's performance with its peers.
- Assisted in the development of a Total Factor Productivity Analysis for a Canadian natural gas utility as part of an Incentive Ratemaking report filed with the Ontario Energy Board.

VALUATION

- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared expert testimony regarding the fair value of the distribution system assets of a Midwest natural gas utility and the fair value of the transmission and distribution system assets of a different Midwest electric utility.

EXPERT TESTIMONY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2014	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Rebuttal Testimony on Statistical Concepts for Return on Equity and Class Cost of Service
Massachusetts Department of Public Utilities				
Berkshire Gas Company	2020	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas	07/23	EnergyNorth Natural Gas	Docket No. DG 23-067	Return on Equity
Granite State Electric	05/23	Granite State Electric	Docket No. DE 23-039	Return on Equity
New York State Department of Public Service				
Liberty Utilities (New York Water)	05/23	Liberty Utilities (New York Water)	Case No. 23-W-0235	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity

SUMMARY OF COST OF EQUITY ANALYSIS RESULTS

Constant Growth DCF - Earnings Growth	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean:			
30-Day Avg. Stock Price	8.92%	10.02%	11.49%
90-Day Avg. Stock Price	8.84%	9.94%	11.41%
180-Day Avg. Stock Price	8.85%	9.96%	11.42%
Average	8.87%	9.97%	11.44%
Median:			
30-Day Avg. Stock Price	8.75%	10.08%	11.13%
90-Day Avg. Stock Price	8.58%	10.12%	10.90%
180-Day Avg. Stock Price	8.55%	10.16%	10.82%
Average	8.62%	10.12%	10.95%

CAPM, ECAPM, and Bond Yield Risk Premium	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.10%	11.09%	11.08%
Current Bloomberg Beta	10.58%	10.57%	10.56%
Long-term Avg. *Value Line* Beta	10.28%	10.27%	10.26%
ECAPM:			
Current *Value Line* Beta	11.49%	11.49%	11.48%
Current Bloomberg Beta	11.11%	11.10%	11.09%
Long-term Avg. *Value Line* Beta	10.88%	10.87%	10.86%
Bond Yield Risk Premium:	10.14%	10.12%	10.11%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A-	Yes	Yes	100.00%	66.03%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	100.17%	65.58%	No
Northwest Natural Gas Company	NWN	Yes	A+	Yes	Yes	99.84%	91.01%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100.00%	100.00%	No
Spire, Inc.	SR	Yes	A-	Yes	Yes	86.84%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Form 10-K's for 2022, 2021, and 2020
[6] Form 10-K's for 2022, 2021, and 2020
[7] S&P Capital IQ Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$115.97	2.55%	2.65%	7.00%	7.80%	7.50%	7.43%	9.64%	10.08%	10.45%
NiSource Inc.	NI	$1.00	$27.13	3.69%	3.83%	9.50%	6.70%	7.00%	7.73%	10.51%	11.56%	13.36%
Northwest Natural Gas Company	NWN	$1.94	$43.23	4.49%	4.58%	6.50%	2.80%	3.70%	4.33%	7.35%	8.92%	11.13%
ONE Gas, Inc.	OGS	$2.60	$79.63	3.27%	3.35%	6.50%	5.00%	5.00%	5.50%	8.35%	8.85%	9.87%
Spire, Inc.	SR	$2.88	$64.67	4.45%	4.59%	8.00%	n/a	4.20%	6.10%	8.75%	10.69%	12.63%
Mean										8.92%	10.02%	11.49%
Median										8.75%	10.08%	11.13%

Notes:
[1] Bloomberg Professional as of June 30 2023
[2] Bloomberg Professional 30-day average as of June 30 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Yahoo! Finance Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$114.09	2.59%	2.69%	7.00%	7.80%	7.50%	7.43%	9.69%	10.12%	10.50%
NiSource Inc.	NI	$1.00	$27.52	3.63%	3.77%	9.50%	6.70%	7.00%	7.73%	10.46%	11.51%	13.31%
Northwest Natural Gas Company	NWN	$1.94	$45.56	4.26%	4.35%	6.50%	2.80%	3.70%	4.33%	7.12%	8.68%	10.90%
ONE Gas, Inc.	OGS	$2.60	$78.95	3.29%	3.38%	6.50%	5.00%	5.00%	5.50%	8.38%	8.88%	9.90%
Spire, Inc.	SR	$2.88	$67.16	4.29%	4.42%	8.00%	n/a	4.20%	6.10%	8.58%	10.52%	12.46%
Mean										8.84%	9.94%	11.41%
Median										8.58%	10.12%	10.90%

Notes:
[1] Bloomberg Professional as of June 30 2023
[2] Bloomberg Professional 90-day average as of June 30 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$2.96	$112.48	2.63%	2.73%	7.00%	7.80%	7.50%	7.43%	9.72%	10.16%	10.53%
NiSource Inc.	NI	$1.00	$26.89	3.72%	3.86%	9.50%	6.70%	7.00%	7.73%	10.54%	11.60%	13.40%
Northwest Natural Gas Company	NWN	$1.94	$46.33	4.19%	4.28%	6.50%	2.80%	3.70%	4.33%	7.05%	8.61%	10.82%
ONE Gas, Inc.	OGS	$2.60	$78.12	3.33%	3.42%	6.50%	5.00%	5.00%	5.50%	8.41%	8.92%	9.94%
Spire, Inc.	SR	$2.88	$67.64	4.26%	4.39%	8.00%	n/a	4.20%	6.10%	8.55%	10.49%	12.43%
Mean										8.85%	9.96%	11.42%
Median										8.55%	10.16%	10.82%

Notes:
[1] Bloomberg Professional as of June 30 2023
[2] Bloomberg Professional 180-day average as of June 30 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.89%	0.85	12.68%	8.79%	11.36%	11.69%
NiSource Inc.	NI	3.89%	0.85	12.68%	8.79%	11.36%	11.69%
Northwest Natural Gas Company	NWN	3.89%	0.80	12.68%	8.79%	10.92%	11.36%
ONE Gas, Inc.	OGS	3.89%	0.80	12.68%	8.79%	10.92%	11.36%
Spire, Inc.	SR	3.89%	0.80	12.68%	8.79%	10.92%	11.36%
Mean						11.10%	11.49%
Median						10.92%	11.36%

Notes:
[1] Source: Bloomberg Professional 30-day average as of June 30, 2023
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.84%	0.85	12.68%	8.84%	11.36%	11.69%
NiSource Inc.	NI	3.84%	0.85	12.68%	8.84%	11.36%	11.69%
Northwest Natural Gas Company	NWN	3.84%	0.80	12.68%	8.84%	10.91%	11.36%
ONE Gas, Inc.	OGS	3.84%	0.80	12.68%	8.84%	10.91%	11.36%
Spire, Inc.	SR	3.84%	0.80	12.68%	8.84%	10.91%	11.36%
Mean						11.09%	11.49%
Median						10.91%	11.36%

Notes:
[1] Source: *Blue Chip Financial Forecasts* , Vol. 42, No. 7, June 30, 2023, at 2
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.85	12.68%	8.88%	11.35%	11.68%
NiSource Inc.	NI	3.80%	0.85	12.68%	8.88%	11.35%	11.68%
Northwest Natural Gas Company	NWN	3.80%	0.80	12.68%	8.88%	10.91%	11.35%
ONE Gas, Inc.	OGS	3.80%	0.80	12.68%	8.88%	10.91%	11.35%
Spire, Inc.	SR	3.80%	0.80	12.68%	8.88%	10.91%	11.35%
Mean						11.08%	11.48%
Median						10.91%	11.35%

Notes:
[1] Source: *Blue Chip Financial Forecasts* , Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: Value Line
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \text{ x } (Rm - Rf) + 0.75 \text{ x } \beta \text{ x } (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.89%	0.75	12.68%	8.79%	10.50%	11.05%
NiSource Inc.	NI	3.89%	0.81	12.68%	8.79%	11.05%	11.46%
Northwest Natural Gas Company	NWN	3.89%	0.70	12.68%	8.79%	10.03%	10.69%
ONE Gas, Inc.	OGS	3.89%	0.78	12.68%	8.79%	10.76%	11.24%
Spire, Inc.	SR	3.89%	0.76	12.68%	8.79%	10.57%	11.10%
Mean						10.58%	11.11%
Median						10.57%	11.10%

Notes:
[1] Source: Bloomberg Professional 30-day average as of June 30, 2023
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.84%	0.75	12.68%	8.84%	10.49%	11.04%
NiSource Inc.	NI	3.84%	0.81	12.68%	8.84%	11.05%	11.45%
Northwest Natural Gas Company	NWN	3.84%	0.70	12.68%	8.84%	10.01%	10.68%
ONE Gas, Inc.	OGS	3.84%	0.78	12.68%	8.84%	10.74%	11.23%
Spire, Inc.	SR	3.84%	0.76	12.68%	8.84%	10.56%	11.09%
Mean						10.57%	11.10%
Median						10.56%	11.09%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 7, June 30, 2023, at 2
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.75	12.68%	8.88%	10.48%	11.03%
NiSource Inc.	NI	3.80%	0.81	12.68%	8.88%	11.04%	11.45%
Northwest Natural Gas Company	NWN	3.80%	0.70	12.68%	8.88%	10.00%	10.67%
ONE Gas, Inc.	OGS	3.80%	0.78	12.68%	8.88%	10.74%	11.22%
Spire, Inc.	SR	3.80%	0.76	12.68%	8.88%	10.55%	11.08%
Mean						10.56%	11.09%
Median						10.55%	11.08%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: Bloomberg Professional
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.89%	0.74	12.68%	8.79%	10.40%	10.97%
NiSource Inc.	NI	3.89%	0.74	12.68%	8.79%	10.37%	10.95%
Northwest Natural Gas Company	NWN	3.89%	0.70	12.68%	8.79%	10.04%	10.70%
ONE Gas, Inc.	OGS	3.89%	0.73	12.68%	8.79%	10.30%	10.89%
Spire, Inc.	SR	3.89%	0.73	12.68%	8.79%	10.31%	10.90%
Mean						10.28%	10.88%
Median						10.31%	10.90%

Notes:
[1] Source: Bloomberg Professional 30-day average as of June 30, 2023
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q4 2023 - Q4 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.84%	0.74	12.68%	8.84%	10.38%	10.96%
NiSource Inc.	NI	3.84%	0.74	12.68%	8.84%	10.36%	10.94%
Northwest Natural Gas Company	NWN	3.84%	0.70	12.68%	8.84%	10.03%	10.69%
ONE Gas, Inc.	OGS	3.84%	0.73	12.68%	8.84%	10.28%	10.88%
Spire, Inc.	SR	3.84%	0.73	12.68%	8.84%	10.29%	10.89%
Mean						10.27%	10.87%
Median						10.29%	10.89%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 7, June 30, 2023, at 2
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
Atmos Energy Corporation	ATO	3.80%	0.74	12.68%	8.88%	10.37%	10.95%
NiSource Inc.	NI	3.80%	0.74	12.68%	8.88%	10.35%	10.93%
Northwest Natural Gas Company	NWN	3.80%	0.70	12.68%	8.88%	10.02%	10.68%
ONE Gas, Inc.	OGS	3.80%	0.73	12.68%	8.88%	10.27%	10.87%
Spire, Inc.	SR	3.80%	0.73	12.68%	8.88%	10.28%	10.88%
Mean						10.26%	10.86%
Median						10.28%	10.88%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14
[2] Source: LT Beta
[3] Source: Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.74
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.74
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.70
ONE Gas, Inc.	OGS	NA	NA	NA	0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.73
Spire, Inc.	SR	0.65	0.7	0.7	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.73
Mean		0.74	0.76	0.72	0.69	0.68	0.60	0.61	0.82	0.83	0.82	0.73

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Average ([1] - [10])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Agilent Technologies Inc	A	295.38	120.25	35,518.96	0.13%	0.75%	0.00%	14.00%	0.02%
American Airlines Group Inc	AAL	652.86	17.94	11,712.36				83.22%	
Advance Auto Parts Inc	AAP	59.44	70.30	4,178.91		1.42%		-7.41%	
Apple Inc	AAPL	15,728.70	193.97	3,050,896.33	11.00%	0.49%	0.05%	13.00%	1.43%
AbbVie Inc	ABBV	1,764.29	134.73	237,702.79	0.86%	4.39%	0.04%	1.59%	0.01%
AmerisourceBergen Corp	ABC	201.98	192.43	38,867.59	0.14%	1.01%	0.00%	8.86%	0.01%
Abbott Laboratories	ABT	1,738.95	109.02	189,580.00	0.68%	1.87%	0.01%	1.92%	0.01%
Arch Capital Group Ltd	ACGL	372.42	74.85	27,875.86	0.10%			13.50%	0.01%
Accenture PLC	ACN	664.31	308.58	204,993.40	0.74%	1.45%	0.01%	11.70%	0.09%
Adobe Inc	ADBE	455.80	488.99	222,881.64	0.80%			16.88%	0.14%
Analog Devices Inc	ADI	501.42	194.81	97,681.24	0.35%	1.77%	0.01%	7.50%	0.03%
Archer-Daniels-Midland Co	ADM	544.64	75.56	41,152.62		2.38%		-5.86%	
Automatic Data Processing Inc	ADP	413.12	219.79	90,800.30	0.33%	2.27%	0.01%	16.00%	0.05%
Autodesk Inc	ADSK	213.73	204.61	43,730.48	0.16%			16.39%	0.03%
Ameren Corp	AEE	262.48	81.67	21,436.33	0.08%	3.09%	0.00%	5.85%	0.00%
American Electric Power Co Inc	AEP	514.79	84.20	43,345.40	0.16%	3.94%	0.01%	5.22%	0.01%
AES Corp/The	AES	669.34	20.73	13,875.34	0.05%	3.20%	0.00%	9.12%	0.00%
Aflac Inc	AFL	604.23	69.80	42,175.04	0.15%	2.41%	0.00%	4.39%	0.01%
American International Group Inc	AIG	723.75	57.54	41,644.75	0.15%	2.50%	0.00%	9.50%	0.01%
Assurant Inc	AIZ	53.15	125.72	6,682.27	0.02%	2.23%	0.00%	11.55%	0.00%
Arthur J Gallagher & Co	AJG	214.25	219.57	47,041.99	0.17%	1.00%	0.00%	12.44%	0.02%
Akamai Technologies Inc	AKAM	156.30	89.87	14,047.04	0.05%			10.00%	0.01%
Albemarle Corp	ALB	117.34	223.09	26,176.49		0.72%		36.57%	
Align Technology Inc	ALGN	76.52	353.64	27,059.47	0.10%			17.22%	0.02%
Alaska Air Group Inc	ALK	127.91	53.18	6,802.31				23.78%	
Allstate Corp/The	ALL	262.85	109.04	28,661.38		3.26%		-3.00%	
Allegion plc	ALLE	87.95	120.02	10,555.40	0.04%	1.50%	0.00%	6.08%	0.00%
Applied Materials Inc	AMAT	839.75	144.54	121,377.03	0.44%	0.89%	0.00%	1.87%	0.01%
Amcor PLC	AMCR	1,471.44	9.98	14,685.01	0.05%	4.91%	0.00%	0.41%	0.00%
Advanced Micro Devices Inc	AMD	1,610.36	113.91	183,436.34	0.66%			6.10%	0.04%
AMETEK Inc	AME	230.48	161.88	37,309.29	0.13%	0.62%	0.00%	6.86%	0.01%
Amgen Inc	AMGN	534.33	222.02	118,631.28	0.43%	3.84%	0.02%	5.00%	0.02%
Ameriprise Financial Inc	AMP	104.18	332.16	34,604.10	0.12%	1.63%	0.00%	16.82%	0.02%
American Tower Corp	AMT	466.04	193.94	90,384.38		3.24%		21.16%	
Amazon.com Inc	AMZN	10,260.35	130.36	1,337,539.75				59.71%	
Arista Networks Inc	ANET	308.28	162.06	49,960.34	0.18%			18.07%	0.03%
ANSYS Inc	ANSS	86.66	330.27	28,621.53	0.10%			10.26%	0.01%
Aon PLC	AON	204.25	345.20	70,505.72	0.25%	0.71%	0.00%	10.06%	0.03%
A O Smith Corp	AOS	124.54	72.78	9,063.88		1.65%			
APA Corp	APA	308.60	34.17	10,544.83	0.04%	2.93%	0.00%	11.16%	0.00%
Air Products and Chemicals Inc	APD	222.12	299.53	66,532.50	0.24%	2.34%	0.01%	10.26%	0.02%
Amphenol Corp	APH	595.32	84.95	50,572.35	0.18%	0.99%	0.00%	5.06%	0.01%
Aptiv PLC	APTV	270.51	102.09	27,615.96	0.10%			11.94%	0.01%
Alexandria Real Estate Equities Inc	ARE	173.01	113.49	19,635.36	0.07%	4.37%	0.00%	9.71%	0.01%
Atmos Energy Corp	ATO	144.49	116.34	16,809.62		2.54%			
Activision Blizzard Inc	ATVI	786.16	84.30	66,273.20	0.24%			5.00%	0.01%
AvalonBay Communities Inc	AVB	142.00	189.27	26,876.15	0.10%	3.49%	0.00%	8.50%	0.01%
Broadcom Inc	AVGO	412.69	867.43	357,975.35	1.29%	2.12%	0.03%	12.79%	0.17%
Avery Dennison Corp	AVY	80.73	171.80	13,869.07	0.05%	1.89%	0.00%	7.00%	0.00%
American Water Works Co Inc	AWK	194.64	142.75	27,785.43	0.10%	1.98%	0.00%	7.73%	0.01%
Axon Enterprise Inc	AXON	73.89	195.12	14,416.44	0.05%			15.10%	0.01%
American Express Co	AXP	743.24	174.20	129,472.58	0.47%	1.38%	0.01%	12.00%	0.06%
AutoZone Inc	AZO	18.16	2,493.36	45,269.44	0.16%			13.48%	0.02%
Boeing Co/The	BA	601.59	211.16	127,032.59				122.26%	
Bank of America Corp	BAC	7,969.15	28.69	228,635.00		3.07%		-2.00%	
Ball Corp	BALL	314.55	58.21	18,309.84	0.07%	1.37%	0.00%	9.50%	0.01%
Baxter International Inc	BAX	505.52	45.56	23,031.63	0.08%	2.55%	0.00%	0.88%	0.00%
Bath & Body Works Inc	BBWI	228.91	37.50	8,584.20	0.03%	2.13%	0.00%	11.46%	0.00%
Best Buy Co Inc	BBY	218.21	81.95	17,882.39	0.06%	4.49%	0.00%	3.14%	0.00%
Becton Dickinson & Co	BDX	284.02	264.01	74,982.80	0.27%	1.38%	0.00%	9.60%	0.03%
Franklin Resources Inc	BEN	500.86	26.71	13,378.05		4.49%		-5.83%	
Brown-Forman Corp	BF/B	310.11	66.78	20,709.15	0.07%	1.23%	0.00%	8.55%	0.01%
Bunge Ltd	BG	150.62	94.35	14,210.81		2.81%		-5.81%	
Biogen Inc	BIIB	144.74	284.85	41,229.76	0.15%			5.19%	0.01%
Bio-Rad Laboratories Inc	BIO	24.54	379.12	9,302.09					
Bank of New York Mellon Corp/The	BK	789.13	44.52	35,132.25	0.13%	3.32%	0.00%	10.00%	0.01%
Booking Holdings Inc	BKNG	36.93	2,700.33	99,733.99	0.36%			20.00%	0.07%
Baker Hughes Co	BKR	1,012.36	31.61	32,000.76	0.12%	2.40%	0.00%	16.00%	0.02%
BlackRock Inc	BLK	149.76	691.14	103,507.20	0.37%	2.89%	0.01%	9.16%	0.03%
Bristol-Myers Squibb Co	BMY	2,100.85	63.95	134,349.17	0.48%	3.57%	0.02%	3.56%	0.02%
Broadridge Financial Solutions Inc	BR	117.98	165.63	19,541.19		1.75%			
Berkshire Hathaway Inc	BRK/B	1,295.97	341.00	441,926.11					
Brown & Brown Inc	BRO	283.64	68.84	19,526.05	0.07%	0.67%	0.00%	8.00%	0.01%
Boston Scientific Corp	BSX	1,437.70	54.09	77,765.08	0.28%			11.48%	0.03%
BorgWarner Inc	BWA	234.37	48.91	11,463.18	0.04%	1.39%	0.00%	12.56%	0.01%
Boston Properties Inc	BXP	156.84	57.59	9,032.13		6.81%		-11.97%	

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Citigroup Inc	C	1,946.75	46.04	89,628.46		4.43%		-4.06%	
Conagra Brands Inc	CAG	476.91	33.72	16,081.30	0.06%	3.91%	0.00%	6.71%	0.00%
Cardinal Health Inc	CAH	254.60	94.57	24,077.52	0.09%	2.12%	0.00%	13.20%	0.01%
Carrier Global Corp	CARR	834.84	49.71	41,499.80	0.15%	1.49%	0.00%	10.65%	0.02%
Caterpillar Inc	CAT	515.36	246.05	126,803.34	0.46%	2.11%	0.01%	15.00%	0.07%
Chubb Ltd	CB	414.17	192.56	79,753.35	0.29%	1.79%	0.01%	14.00%	0.04%
Cboe Global Markets Inc	CBOE	105.57	138.01	14,570.27		1.45%			
CBRE Group Inc	CBRE	310.83	80.71	25,087.25					
Crown Castle Inc	CCI	433.67	113.94	49,412.47		5.49%			
Carnival Corp	CCL	1,116.01	18.83	21,014.54					
Ceridian HCM Holding Inc	CDAY	155.03	66.97	10,382.43					
Cadence Design Systems Inc	CDNS	272.68	234.52	63,949.85	0.23%			19.50%	0.04%
CDW Corp/DE	CDW	134.79	183.50	24,733.41	0.09%	1.29%	0.00%	13.10%	0.01%
Celanese Corp	CE	108.79	115.80	12,597.65	0.05%	2.42%	0.00%	10.27%	0.00%
Constellation Energy Corp	CEG	326.66	91.55	29,906.09		1.23%		-152.23%	
CF Industries Holdings Inc	CF	194.92	69.42	13,531.35	0.05%	2.30%	0.00%	6.00%	0.00%
Citizens Financial Group Inc	CFG	483.99	26.08	12,622.41		6.44%		-2.40%	
Church & Dwight Co Inc	CHD	244.26	100.23	24,482.58	0.09%	1.09%	0.00%	5.35%	0.00%
CH Robinson Worldwide Inc	CHRW	116.44	94.35	10,986.02	0.04%	2.59%	0.00%	10.00%	0.00%
Charter Communications Inc	CHTR	150.58	367.37	55,316.74	0.20%			14.44%	0.03%
Cigna Group/The	CI	295.87	280.60	83,021.68	0.30%	1.75%	0.01%	10.80%	0.03%
Cincinnati Financial Corp	CINF	157.21	97.32	15,299.97	0.06%	3.08%	0.00%	16.50%	0.01%
Colgate-Palmolive Co	CL	829.57	77.04	63,909.92	0.23%	2.49%	0.01%	6.17%	0.01%
Clorox Co/The	CLX	123.62	159.04	19,661.16	0.07%	2.97%	0.00%	17.02%	0.01%
Comerica Inc	CMA	131.67	42.36	5,577.54	0.02%	6.70%	0.00%	15.09%	0.00%
Comcast Corp	CMCSA	4,159.38	41.26	171,616.14	0.62%	2.81%	0.02%	7.90%	0.05%
CME Group Inc	CME	359.72	185.29	66,651.59	0.24%	2.37%	0.01%	4.67%	0.01%
Chipotle Mexican Grill Inc	CMG	27.59	2,139.00	59,015.01				24.42%	
Cummins Inc	CMI	141.56	245.16	34,705.34		2.56%			
CMS Energy Corp	CMS	291.66	58.75	17,134.79	0.06%	3.32%	0.00%	7.75%	0.00%
Centene Corp	CNC	548.77	67.45	37,014.47	0.13%			8.18%	0.01%
CenterPoint Energy Inc	CNP	629.43	29.15	18,347.94	0.07%	2.61%	0.00%	7.42%	0.00%
Capital One Financial Corp	COF	381.81	109.37	41,758.12		2.19%		-3.33%	
Cooper Cos Inc/The	COO	49.51	383.43	18,982.85	0.07%	0.02%	0.00%	9.00%	0.01%
ConocoPhillips	COP	1,211.88	103.61	125,562.78		0.58%		-8.00%	
Costco Wholesale Corp	COST	443.15	538.38	238,582.02	0.86%	0.76%	0.01%	12.46%	0.11%
Campbell Soup Co	CPB	298.09	45.71	13,625.79	0.05%	3.24%	0.00%	3.39%	0.00%
Copart Inc	CPRT	477.44	91.21	43,547.30	0.16%			10.00%	0.02%
Camden Property Trust	CPT	106.76	108.87	11,623.18	0.04%	3.67%	0.00%	3.48%	0.00%
Charles River Laboratories International Inc	CRL	51.18	210.25	10,761.23	0.04%			14.00%	0.01%
Salesforce Inc	CRM	974.00	211.26	205,767.24				22.50%	
Cisco Systems Inc	CSCO	4,075.06	51.74	210,843.50	0.76%	3.02%	0.02%	7.50%	0.06%
CoStar Group Inc	CSGP	408.54	89.00	36,359.97	0.13%			20.00%	0.03%
CSX Corp	CSX	2,033.06	34.10	69,327.18	0.25%	1.29%	0.00%	4.31%	0.01%
Cintas Corp	CTAS	101.70	497.08	50,554.03	0.18%	0.93%	0.00%	10.96%	0.02%
Catalent Inc	CTLT	180.27	43.36	7,816.59	0.03%			12.00%	0.00%
Coterra Energy Inc	CTRA	757.45	25.30	19,163.56		3.16%		55.04%	
Cognizant Technology Solutions Corp	CTSH	507.48	65.28	33,128.10	0.12%	1.78%	0.00%	12.00%	0.01%
Corteva Inc	CTVA	710.68	57.30	40,721.85		1.05%		21.08%	
CVS Health Corp	CVS	1,282.03	69.13	88,626.39	0.32%	3.50%	0.01%	6.88%	0.02%
Chevron Corp	CVX	1,894.64	157.35	298,122.08	1.08%	3.84%	0.04%	8.27%	0.09%
Caesars Entertainment Inc	CZR	215.20	50.97	10,968.95					
Dominion Energy Inc	D	835.94	51.79	43,293.38		5.16%		-1.77%	
Delta Air Lines Inc	DAL	642.72	47.54	30,554.67		0.84%		37.34%	
DuPont de Nemours Inc	DD	459.02	71.44	32,792.17	0.12%	2.02%	0.00%	7.53%	0.01%
Deere & Co	DE	293.19	405.19	118,798.47	0.43%	1.23%	0.01%	17.28%	0.07%
Discover Financial Services	DFS	253.95	116.85	29,673.59		2.40%		57.51%	
Dollar General Corp	DG	219.34	169.78	37,239.71	0.13%	1.39%	0.00%	3.36%	0.00%
Quest Diagnostics Inc	DGX	112.01	140.56	15,743.99		2.02%		-20.51%	
DR Horton Inc	DHI	341.07	121.69	41,504.93		0.82%		-7.54%	
Danaher Corp	DHR	737.90	240.00	177,095.76		0.45%		20.37%	
Walt Disney Co/The	DIS	1,827.31	89.28	163,141.79				20.54%	
Digital Realty Trust Inc	DLR	291.35	113.87	33,175.68	0.12%	4.29%	0.01%	6.59%	0.01%
Dollar Tree Inc	DLTR	220.39	143.50	31,625.25	0.11%			9.23%	0.01%
Dover Corp	DOV	139.85	147.65	20,649.00	0.07%	1.37%	0.00%	13.00%	0.01%
Dow Inc	DOW	707.99	53.26	37,707.49	0.14%	5.26%	0.01%	4.64%	0.01%
Domino's Pizza Inc	DPZ	35.34	336.99	11,908.89	0.04%	1.44%	0.00%	11.83%	0.01%
Darden Restaurants Inc	DRI	120.93	167.08	20,204.82	0.07%	3.14%	0.00%	10.26%	0.01%
DTE Energy Co	DTE	206.11	110.02	22,676.11	0.08%	3.46%	0.00%	6.50%	0.01%
Duke Energy Corp	DUK	771.00	89.74	69,189.54	0.25%	4.48%	0.01%	6.12%	0.02%
DaVita Inc	DVA	90.70	100.47	9,112.63	0.03%			14.60%	0.00%
Devon Energy Corp	DVN	641.70	48.34	31,019.78		5.96%		21.68%	
DXC Technology Co	DXC	210.07	26.72	5,613.18	0.02%			11.42%	0.00%
Dexcom Inc	DXCM	387.64	128.51	49,815.10				27.20%	
Electronic Arts Inc	EA	272.12	129.70	35,293.57	0.13%	0.59%	0.00%	7.27%	0.01%
eBay Inc	EBAY	534.50	44.69	23,886.94	0.09%	2.24%	0.00%	2.23%	0.00%

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Ecolab Inc	ECL	284.72	186.69	53,154.56	0.19%	1.14%	0.00%	14.00%	0.03%
Consolidated Edison Inc	ED	346.54	90.40	31,327.22	0.11%	3.58%	0.00%	2.00%	0.00%
Equifax Inc	EFX	122.64	235.30	28,858.13	0.10%	0.66%	0.00%	11.60%	0.01%
Edison International	EIX	382.98	68.71	26,315.72	0.09%	4.29%	0.00%	5.42%	0.01%
Estee Lauder Cos Inc/The	EL	231.87	196.38	45,534.83	0.16%	1.34%	0.00%	18.89%	0.03%
Elevance Health Inc	ELV	237.06	444.29	105,321.61	0.38%	1.33%	0.01%	10.38%	0.04%
Eastman Chemical Co	EMN	119.14	83.72	9,974.23	0.04%	3.77%	0.00%	8.50%	0.00%
Emerson Electric Co	EMR	571.50	90.39	51,657.89	0.19%	2.30%	0.00%	10.31%	0.02%
Enphase Energy Inc	ENPH	137.04	167.48	22,952.13				24.70%	
EOG Resources Inc	EOG	584.86	114.44	66,931.26	0.24%	2.88%	0.01%	10.83%	0.03%
EPAM Systems Inc	EPAM	57.91	224.75	13,014.37	0.05%			4.39%	0.00%
Equinix Inc	EQIX	93.52	783.94	73,316.42	0.26%	1.74%	0.00%	14.99%	0.04%
Equity Residential	EQR	378.91	65.97	24,996.36	0.09%	4.02%	0.00%	4.99%	0.00%
EQT Corp	EQT	361.64	41.13	14,874.38		1.46%		29.41%	
Eversource Energy	ES	348.84	70.92	24,739.87	0.09%	3.81%	0.00%	5.96%	0.01%
Essex Property Trust Inc	ESS	64.18	234.30	15,037.84	0.05%	3.94%	0.00%	6.45%	0.00%
Eaton Corp PLC	ETN	398.60	201.10	80,158.46	0.29%	1.71%	0.00%	15.00%	0.04%
Entergy Corp	ETR	211.45	97.37	20,588.59	0.07%	4.40%	0.00%	6.35%	0.00%
Etsy Inc	ETSY	123.35	84.61	10,436.81	0.04%			15.56%	0.01%
Evergy Inc	EVRG	229.58	58.42	13,412.24	0.05%	4.19%	0.00%	4.74%	0.00%
Edwards Lifesciences Corp	EW	606.22	94.33	57,184.54	0.21%			10.41%	0.02%
Exelon Corp	EXC	994.30	40.74	40,507.74	0.15%	3.53%	0.01%	17.68%	0.03%
Expeditors International of Washington Inc	EXPD	152.79	121.13	18,507.69		1.14%			
Expedia Group Inc	EXPE	142.60	109.39	15,599.12	0.06%			17.50%	0.01%
Extra Space Storage Inc	EXR	135.05	148.85	20,102.19	0.07%	4.35%	0.00%	3.96%	0.00%
Ford Motor Co	F	3,929.92	15.13	59,459.66		3.97%		-6.27%	
Diamondback Energy Inc	FANG	181.09	131.36	23,788.38	0.09%	2.53%	0.00%	11.47%	0.01%
Fastenal Co	FAST	570.96	58.99	33,680.99		2.37%			
Freeport-McMoRan Inc	FCX	1,433.29	40.00	57,331.44		1.50%		-11.56%	
FactSet Research Systems Inc	FDS	38.32	400.65	15,352.51	0.06%	0.98%	0.00%	11.97%	0.01%
FedEx Corp	FDX	251.35	247.90	62,310.16	0.22%	2.03%	0.00%	12.75%	0.03%
FirstEnergy Corp	FE	572.84	38.88	22,271.90		4.01%		-0.83%	
F5 Inc	FFIV	60.47	146.26	8,844.05	0.03%			10.73%	0.00%
Fiserv Inc	FI	617.31	126.15	77,873.66	0.28%			13.21%	0.04%
Fair Isaac Corp	FICO	24.99	809.21	20,224.59					
Fidelity National Information Services Inc	FIS	592.44	54.70	32,406.30	0.12%	3.80%	0.00%	3.11%	0.00%
Fifth Third Bancorp	FITB	680.72	26.21	17,841.57		5.04%		25.00%	
FleetCor Technologies Inc	FLT	73.83	251.08	18,538.24	0.07%			12.18%	0.01%
FMC Corp	FMC	125.04	104.34	13,046.57	0.05%	2.22%	0.00%	8.00%	0.00%
Fox Corp	FOX	235.58	31.89	7,512.68	0.03%	1.57%	0.00%	10.84%	0.00%
Fox Corp	FOXA	269.06	34.00	9,147.94	0.03%	1.47%	0.00%	10.84%	0.00%
Federal Realty Investment Trust	FRT	81.52	96.77	7,888.21	0.03%	4.46%	0.00%	6.20%	0.00%
First Solar Inc	FSLR	106.83	190.09	20,306.55				45.17%	
Fortinet Inc	FTNT	785.20	75.59	59,352.97	0.21%			17.50%	0.04%
Fortive Corp	FTV	351.74	74.77	26,299.75	0.09%	0.37%	0.00%	7.84%	0.01%
General Dynamics Corp	GD	274.34	215.15	59,023.39	0.21%	2.45%	0.01%	10.90%	0.02%
General Electric Co	GE	1,088.96	109.85	119,622.26	0.43%	0.29%	0.00%	7.00%	0.03%
GE HealthCare Technologies Inc	GEHC	454.68	81.24	36,937.96		0.15%			
Gen Digital Inc	GEN	640.77	18.55	11,886.30		2.70%			
Gilead Sciences Inc	GILD	1,248.82	77.07	96,246.25	0.35%	3.89%	0.01%	0.29%	0.00%
General Mills Inc	GIS	585.18	76.70	44,883.54	0.16%	3.08%	0.00%	8.00%	0.01%
Globe Life Inc	GL	95.56	109.40	10,453.25		0.82%			
Corning Inc	GLW	850.13	35.04	29,788.56	0.11%	3.20%	0.00%	7.69%	0.01%
General Motors Co	GM	1,390.12	38.56	53,603.14		0.93%		-3.15%	
Generac Holdings Inc	GNRC	62.19	149.13	9,274.84	0.03%			8.00%	0.00%
Alphabet Inc	GOOG	5,874.00	120.97	710,577.78	2.56%			15.82%	0.41%
Alphabet Inc	GOOGL	5,941.00	119.70	711,137.70	2.56%			15.82%	0.41%
Genuine Parts Co	GPC	140.52	169.23	23,779.52	0.09%	2.25%	0.00%	8.92%	0.01%
Global Payments Inc	GPN	261.95	98.52	25,807.61	0.09%	1.02%	0.00%	13.69%	0.01%
Garmin Ltd	GRMN	191.29	104.29	19,949.63	0.07%	2.80%	0.00%	5.60%	0.00%
Goldman Sachs Group Inc/The	GS	332.45	322.54	107,227.78	0.39%	3.10%	0.01%	9.94%	0.04%
WW Grainger Inc	GWW	50.17	788.59	39,561.19		0.94%			
Halliburton Co	HAL	902.20	32.99	29,763.41		1.94%		26.61%	
Hasbro Inc	HAS	138.61	64.77	8,977.70	0.03%	4.32%	0.00%	2.48%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,443.62	10.78	15,562.17		5.75%		-2.49%	
HCA Healthcare Inc	HCA	275.19	303.48	83,514.66	0.30%	0.79%	0.00%	8.35%	0.03%
Home Depot Inc/The	HD	1,005.38	310.64	312,310.00	1.13%	2.69%	0.03%	0.56%	0.01%
Hess Corp	HES	307.05	135.95	41,743.72		1.29%		-23.46%	
Hartford Financial Services Group Inc/The	HIG	310.24	72.02	22,343.12	0.08%	2.36%	0.00%	7.00%	0.01%
Huntington Ingalls Industries Inc	HII	39.89	227.60	9,079.19		2.18%		40.00%	
Hilton Worldwide Holdings Inc	HLT	264.63	145.55	38,516.46		0.41%		38.66%	
Hologic Inc	HOLX	246.12	80.97	19,928.17				-26.07%	
Honeywell International Inc	HON	665.68	207.50	138,127.98	0.50%	1.99%	0.01%	9.50%	0.05%
Hewlett Packard Enterprise Co	HPE	1,291.52	16.80	21,697.50	0.08%	2.86%	0.00%	3.72%	0.00%
HP Inc	HPQ	985.96	30.71	30,278.71		3.42%		-4.44%	
Hormel Foods Corp	HRL	546.27	40.22	21,970.90	0.08%	2.73%	0.00%	2.50%	0.00%

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Henry Schein Inc	HSIC	131.00	81.10	10,624.34	0.04%			5.04%	0.00%
Host Hotels & Resorts Inc	HST	711.24	16.83	11,970.19		3.57%			
Hershey Co/The	HSY	147.29	249.70	36,777.06	0.13%	1.66%	0.00%	9.50%	0.01%
Humana Inc	HUM	124.95	447.13	55,866.66	0.20%	0.79%	0.00%	13.82%	0.03%
Howmet Aerospace Inc	HWM	413.29	49.56	20,482.70	0.07%	0.32%	0.00%	16.69%	0.01%
International Business Machines Corp	IBM	908.05	133.81	121,505.50	0.44%	4.96%	0.02%	3.15%	0.01%
Intercontinental Exchange Inc	ICE	559.87	113.08	63,309.76	0.23%	1.49%	0.00%	9.61%	0.02%
IDEXX Laboratories Inc	IDXX	83.01	502.23	41,687.60	0.15%			17.27%	0.03%
IDEX Corp	IEX	75.58	215.26	16,268.49	0.06%	1.19%	0.00%	13.00%	0.01%
International Flavors & Fragrances Inc	IFF	255.09	79.59	20,302.69		4.07%		21.71%	
Illumina Inc	ILMN	158.10	187.49	29,642.17				22.20%	
Incyte Corp	INCY	223.09	62.25	13,887.23				66.93%	
Intel Corp	INTC	4,171.00	33.44	139,478.24	0.50%	1.50%	0.01%	0.83%	0.00%
Intuit Inc	INTU	280.06	458.19	128,320.69	0.46%	0.68%	0.00%	15.94%	0.07%
Invitation Homes Inc	INVH	611.92	34.40	21,049.98	0.08%	3.02%	0.00%	7.16%	0.01%
International Paper Co	IP	347.06	31.81	11,039.88		5.82%		-2.00%	
Interpublic Group of Cos Inc/The	IPG	386.03	38.58	14,893.15	0.05%	3.21%	0.00%	8.07%	0.00%
IQVIA Holdings Inc	IQV	185.55	224.77	41,705.85	0.15%			10.73%	0.02%
Ingersoll Rand Inc	IR	404.52	65.36	26,439.43		0.12%			
Iron Mountain Inc	IRM	291.62	56.82	16,570.02	0.06%	4.35%	0.00%	4.00%	0.00%
Intuitive Surgical Inc	ISRG	350.40	341.94	119,815.09	0.43%			14.66%	0.06%
Gartner Inc	IT	79.04	350.31	27,689.20	0.10%			7.53%	0.01%
Illinois Tool Works Inc	ITW	303.90	250.16	76,024.37	0.27%	2.09%	0.01%	3.75%	0.01%
Invesco Ltd	IVZ	458.17	16.81	7,701.82	0.03%	4.76%	0.00%	8.70%	0.00%
Jacobs Solutions Inc	J	126.85	118.89	15,081.20	0.05%	0.87%	0.00%	9.26%	0.01%
JB Hunt Transport Services Inc	JBHT	103.65	181.03	18,763.40		0.93%		27.00%	
Johnson Controls International plc	JCI	686.10	68.14	46,750.79	0.17%	2.17%	0.00%	14.69%	0.02%
Jack Henry & Associates Inc	JKHY	72.88	167.33	12,194.17	0.04%	1.24%	0.00%	5.62%	0.00%
Johnson & Johnson	JNJ	2,598.73	165.52	430,142.45	1.55%	2.88%	0.04%	4.74%	0.07%
Juniper Networks Inc	JNPR	321.59	31.33	10,075.48	0.04%	2.81%	0.00%	7.82%	0.00%
JPMorgan Chase & Co	JPM	2,922.29	145.44	425,017.71		2.75%		-0.50%	
Kellogg Co	K	342.76	67.40	23,101.89	0.08%	3.50%	0.00%	2.40%	0.00%
Keurig Dr Pepper Inc	KDP	1,403.78	31.27	43,896.08	0.16%	2.56%	0.00%	6.85%	0.01%
KeyCorp	KEY	935.26	9.24	8,641.84	0.03%	8.87%	0.00%	8.88%	0.00%
Keysight Technologies Inc	KEYS	178.37	167.45	29,867.72	0.11%			6.74%	0.01%
Kraft Heinz Co/The	KHC	1,227.24	35.50	43,566.91	0.16%	4.51%	0.01%	3.92%	0.01%
Kimco Realty Corp	KIM	619.89	19.72	12,224.27	0.04%	4.67%	0.00%	4.29%	0.00%
KLA Corp	KLAC	137.20	485.02	66,544.26	0.24%	1.07%	0.00%	2.82%	0.01%
Kimberly-Clark Corp	KMB	337.38	138.06	46,578.82	0.17%	3.42%	0.01%	8.52%	0.01%
Kinder Morgan Inc	KMI	2,241.21	17.22	38,593.71	0.14%	6.56%	0.01%	3.00%	0.00%
CarMax Inc	KMX	158.21	83.70	13,242.18					
Coca-Cola Co/The	KO	4,324.58	60.22	260,426.09	0.94%	3.06%	0.03%	6.78%	0.06%
Kroger Co/The	KR	717.75	47.00	33,734.06	0.12%	2.47%	0.00%	5.60%	0.01%
Loews Corp	L	227.90	59.38	13,532.58		0.42%			
Leidos Holdings Inc	LDOS	137.17	88.48	12,136.54	0.04%	1.63%	0.00%	5.95%	0.00%
Lennar Corp	LEN	252.53	125.31	31,644.03		1.20%		-3.15%	
Laboratory Corp of America Holdings	LH	88.60	207.32	18,368.55		1.39%		-26.56%	
L3Harris Technologies Inc	LHX	189.45	195.77	37,089.21	0.13%	2.33%	0.00%	2.58%	0.00%
Linde PLC	LIN	490.77	381.08	187,021.49	0.67%	1.34%	0.01%	13.50%	0.09%
LKQ Corp	LKQ	267.29	58.27	15,574.99		1.89%			
Eli Lilly & Co	LLY	949.27	468.98	445,190.05		0.96%		21.86%	
Lockheed Martin Corp	LMT	253.25	460.38	116,592.62	0.42%	2.61%	0.01%	6.65%	0.03%
Lincoln National Corp	LNC	169.56	25.76	4,367.84		6.99%		109.79%	
Alliant Energy Corp	LNT	251.39	52.48	13,192.84	0.05%	3.45%	0.00%	6.48%	0.00%
Lowe's Cos Inc	LOW	585.98	225.70	132,255.91		1.95%		20.63%	
Lam Research Corp	LRCX	134.34	642.86	86,361.81		1.07%		-0.72%	
Southwest Airlines Co	LUV	595.07	36.21	21,547.59		1.99%		58.03%	
Las Vegas Sands Corp	LVS	764.27	58.00	44,327.72					
Lamb Weston Holdings Inc	LW	145.70	114.95	16,748.67		0.97%		42.74%	
LyondellBasell Industries NV	LYB	325.27	91.83	29,869.91	0.11%	5.44%	0.01%	13.50%	0.01%
Live Nation Entertainment Inc	LYV	229.89	91.11	20,945.37					
Mastercard Inc	MA	940.18	393.30	369,772.79	1.33%	0.58%	0.01%	17.98%	0.24%
Mid-America Apartment Communities Inc	MAA	116.66	151.86	17,715.99		3.69%			
Marriott International Inc/MD	MAR	303.35	183.69	55,723.10	0.20%	1.13%	0.00%	15.54%	0.03%
Masco Corp	MAS	225.09	57.38	12,915.61	0.05%	1.99%	0.00%	4.57%	0.00%
McDonald's Corp	MCD	730.09	298.41	217,867.35	0.79%	2.04%	0.02%	8.89%	0.07%
Microchip Technology Inc	MCHP	545.38	89.59	48,860.95	0.18%	1.71%	0.00%	13.76%	0.02%
McKesson Corp	MCK	135.51	427.31	57,906.06	0.21%	0.51%	0.00%	9.66%	0.02%
Moody's Corp	MCO	183.50	347.72	63,806.62	0.23%	0.89%	0.00%	13.34%	0.03%
Mondelez International Inc	MDLZ	1,361.85	72.94	99,333.56	0.36%	2.11%	0.01%	8.60%	0.03%
Medtronic PLC	MDT	1,330.41	88.10	117,208.68	0.42%	3.13%	0.01%	3.23%	0.01%
MetLife Inc	MET	765.82	56.53	43,291.86	0.16%	3.68%	0.01%	8.61%	0.01%
Meta Platforms Inc	META	2,212.15	286.98	634,843.67	2.29%			19.90%	0.46%
MGM Resorts International	MGM	363.80	43.92	15,978.05					
Mohawk Industries Inc	MHK	63.68	103.16	6,569.23				-3.54%	
McCormick & Co Inc/MD	MKC	251.10	87.23	21,903.45	0.08%	1.79%	0.00%	7.01%	0.01%

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
MarketAxess Holdings Inc	MKTX	37.67	261.42	9,847.43		1.10%			
Martin Marietta Materials Inc	MLM	62.00	461.69	28,623.39	0.10%	0.57%	0.00%	15.70%	0.02%
Marsh & McLennan Cos Inc	MMC	495.06	188.08	93,111.07	0.34%	1.25%	0.00%	10.39%	0.03%
3M Co	MMM	551.67	100.09	55,216.85	0.20%	5.99%	0.01%	10.00%	0.02%
Monster Beverage Corp	MNST	1,046.71	57.44	60,123.14				22.92%	
Altria Group Inc	MO	1,785.04	45.30	80,862.31	0.29%	8.30%	0.02%	6.00%	0.02%
Molina Healthcare Inc	MOH	58.30	301.24	17,562.29	0.06%			13.19%	0.01%
Mosaic Co/The	MOS	332.11	35.00	11,623.82	0.04%	2.29%	0.00%	7.00%	0.00%
Marathon Petroleum Corp	MPC	424.28	116.60	49,471.40		2.57%		29.12%	
Monolithic Power Systems Inc	MPWR	47.42	540.23	25,619.33		0.74%			
Merck & Co Inc	MRK	2,537.44	115.39	292,794.74	1.06%	2.53%	0.03%	14.27%	0.15%
Moderna Inc	MRNA	381.21	121.50	46,316.89				-65.68%	
Marathon Oil Corp	MRO	617.60	23.02	14,217.24		1.74%		-0.17%	
Morgan Stanley	MS	1,670.11	85.40	142,627.74	0.51%	3.63%	0.02%	4.70%	0.02%
MSCI Inc	MSCI	80.06	469.29	37,572.77	0.14%	1.18%	0.00%	14.75%	0.02%
Microsoft Corp	MSFT	7,435.49	340.54	2,532,081.08	9.13%	0.80%	0.07%	15.44%	1.41%
Motorola Solutions Inc	MSI	167.72	293.28	49,188.04		1.20%			
M&T Bank Corp	MTB	165.87	123.76	20,528.07	0.07%	4.20%	0.00%	14.21%	0.01%
Match Group Inc	MTCH	278.46	41.85	11,653.59					
Mettler-Toledo International Inc	MTD	22.02	1,311.64	28,882.31	0.10%			12.64%	0.01%
Micron Technology Inc	MU	1,095.30	63.11	69,124.51		0.73%		-15.93%	
Norwegian Cruise Line Holdings Ltd	NCLH	424.17	21.77	9,234.07					
Nasdaq Inc	NDAQ	490.77	49.85	24,464.73	0.09%	1.77%	0.00%	0.50%	0.00%
Nordson Corp	NDSN	56.99	248.18	14,144.03		1.05%		48.00%	
NextEra Energy Inc	NEE	2,023.42	74.20	150,137.91	0.54%	2.52%	0.01%	8.75%	0.05%
Newmont Corp	NEM	794.73	42.66	33,903.22	0.12%	3.75%	0.00%	10.15%	0.01%
Netflix Inc	NFLX	444.54	440.49	195,815.87				30.78%	
NiSource Inc	NI	413.06	27.35	11,297.27	0.04%	3.66%	0.00%	7.50%	0.00%
NIKE Inc	NKE	1,232.09	110.37	135,985.99	0.49%	1.23%	0.01%	15.34%	0.08%
Northrop Grumman Corp	NOC	151.86	455.80	69,217.33	0.25%	1.64%	0.00%	3.90%	0.01%
ServiceNow Inc	NOW	203.74	561.97	114,495.77				31.25%	
NRG Energy Inc	NRG	230.23	37.39	8,608.37	0.03%	4.04%	0.00%	5.38%	0.00%
Norfolk Southern Corp	NSC	227.64	226.76	51,619.65	0.19%	2.38%	0.00%	3.57%	0.01%
NetApp Inc	NTAP	212.43	76.40	16,229.73	0.06%	2.62%	0.00%	7.40%	0.00%
Northern Trust Corp	NTRS	208.34	74.14	15,446.48	0.06%	4.05%	0.00%	13.00%	0.01%
Nucor Corp	NUE	251.22	163.98	41,195.55		1.24%		-11.34%	
NVIDIA Corp	NVDA	2,470.00	423.02	1,044,859.40		0.04%		44.04%	
NVR Inc	NVR	3.25	6,350.62	20,620.46				-3.03%	
Newell Brands Inc	NWL	414.10	8.70	3,602.67		3.22%		-4.00%	
News Corp	NWS	192.52	19.72	3,796.40	0.01%	1.01%	0.00%	1.60%	0.00%
News Corp	NWSA	380.95	19.50	7,428.49	0.03%	1.03%	0.00%	1.60%	0.00%
NXP Semiconductors NV	NXPI	259.74	204.68	53,164.20		1.98%		34.00%	
Realty Income Corp	O	673.22	59.79	40,251.94	0.15%	5.13%	0.01%	0.25%	0.00%
Old Dominion Freight Line Inc	ODFL	109.65	369.75	40,543.83	0.15%	0.43%	0.00%	3.13%	0.00%
Organon & Co	OGN	255.06	20.81	5,307.84	0.02%	5.38%	0.00%	5.48%	0.00%
ONEOK Inc	OKE	447.44	61.72	27,616.18	0.10%	6.19%	0.01%	8.77%	0.01%
Omnicom Group Inc	OMC	199.52	95.15	18,983.85	0.07%	2.94%	0.00%	4.56%	0.00%
ON Semiconductor Corp	ON	431.87	94.58	40,846.55	0.15%			4.98%	0.01%
Oracle Corp	ORCL	2,714.26	119.09	323,241.10	1.17%	1.34%	0.02%	15.00%	0.17%
O'Reilly Automotive Inc	ORLY	60.88	955.30	58,157.71	0.21%			11.27%	0.02%
Otis Worldwide Corp	OTIS	413.29	89.01	36,787.03	0.13%	1.53%	0.00%	9.00%	0.01%
Occidental Petroleum Corp	OXY	891.75	58.80	52,434.61		1.22%		-14.00%	
Palo Alto Networks Inc	PANW	305.86	255.51	78,149.01				30.00%	
Paramount Global	PARA	610.85	15.91	9,718.67	0.04%	1.26%	0.00%	5.71%	0.00%
Paycom Software Inc	PAYC	60.29	321.24	19,368.52		0.47%			
Paychex Inc	PAYX	360.50	111.87	40,329.14	0.15%	3.18%	0.00%	7.00%	0.01%
PACCAR Inc	PCAR	522.58	83.65	43,713.73	0.16%	1.20%	0.00%	12.00%	0.02%
PG&E Corp	PCG	1,995.78	17.28	34,487.04	0.12%			2.51%	0.00%
Healthpeak Properties Inc	PEAK	547.00	20.10	10,994.62	0.04%	5.97%	0.00%	4.83%	0.00%
Public Service Enterprise Group Inc	PEG	498.97	62.61	31,240.20	0.11%	3.64%	0.00%	6.17%	0.01%
PepsiCo Inc	PEP	1,377.69	185.22	255,176.30	0.92%	2.73%	0.03%	7.69%	0.07%
Pfizer Inc	PFE	5,645.31	36.68	207,069.86		4.47%		-5.32%	
Principal Financial Group Inc	PFG	242.78	75.84	18,412.06	0.07%	3.38%	0.00%	8.76%	0.01%
Procter & Gamble Co/The	PG	2,356.97	151.74	357,646.48	1.29%	2.48%	0.03%	5.14%	0.07%
Progressive Corp/The	PGR	585.40	132.37	77,489.40		0.30%		39.08%	
Parker-Hannifin Corp	PH	128.30	390.04	50,040.57	0.18%	1.52%	0.00%	14.56%	0.03%
PulteGroup Inc	PHM	223.22	77.68	17,340.04		0.82%		-9.54%	
Packaging Corp of America	PKG	89.93	132.16	11,885.41	0.04%	3.78%	0.00%	5.00%	0.00%
Prologis Inc	PLD	923.45	122.63	113,242.67	0.41%	2.84%	0.01%	6.68%	0.03%
Philip Morris International Inc	PM	1,552.20	97.62	151,525.47	0.55%	5.20%	0.03%	7.75%	0.04%
PNC Financial Services Group Inc/The	PNC	399.11	125.95	50,267.65	0.18%	4.76%	0.01%	13.77%	0.02%
Pentair PLC	PNR	164.95	64.60	10,655.77	0.04%	1.36%	0.00%	5.49%	0.00%
Pinnacle West Capital Corp	PNW	113.26	81.46	9,225.83	0.03%	4.25%	0.00%	0.66%	0.00%
Insulet Corp	PODD	69.70	288.34	20,096.14				35.05%	
Pool Corp	POOL	39.04	374.64	14,625.20		1.17%		-1.11%	
PPG Industries Inc	PPG	235.36	148.30	34,903.59	0.13%	1.67%	0.00%	12.12%	0.02%

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

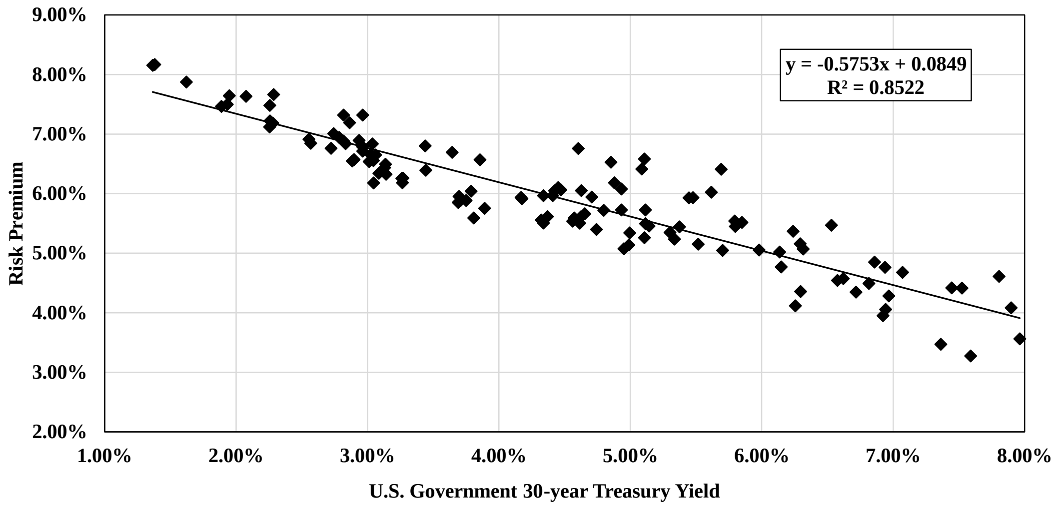
		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
PPL Corp	PPL	737.07	26.46	19,502.82	0.07%	3.63%	0.00%	7.21%	0.01%
Prudential Financial Inc	PRU	365.00	88.22	32,200.30	0.12%	5.67%	0.01%	9.81%	0.01%
Public Storage	PSA	175.81	291.88	51,316.01	0.19%	4.11%	0.01%	3.11%	0.01%
Phillips 66	PSX	460.91	95.38	43,961.88	0.16%	4.40%	0.01%	9.50%	0.02%
PTC Inc	PTC	118.35	142.30	16,841.63	0.06%			14.97%	0.01%
Quanta Services Inc	PWR	145.18	196.45	28,519.83		0.16%			
Pioneer Natural Resources Co	PXD	233.74	207.18	48,425.42		6.45%		-0.73%	
PayPal Holdings Inc	PYPL	1,115.71	66.73	74,451.60	0.27%			15.11%	0.04%
QUALCOMM Inc	QCOM	1,114.00	119.04	132,610.56		2.69%		-0.48%	
Qorvo Inc	QRVO	98.74	102.03	10,074.03				-12.00%	
Royal Caribbean Cruises Ltd	RCL	255.74	103.74	26,530.16				156.50%	
Everest Re Group Ltd	RE	43.42	341.86	14,841.85		1.93%		31.99%	
Regency Centers Corp	REG	171.00	61.77	10,562.55	0.04%	4.21%	0.00%	3.57%	0.00%
Regeneron Pharmaceuticals Inc	REGN	107.89	718.54	77,524.72	0.28%			7.00%	0.02%
Regions Financial Corp	RF	938.31	17.82	16,720.70	0.06%	4.49%	0.00%	2.21%	0.00%
Robert Half International Inc	RHI	107.76	75.22	8,105.93	0.03%	2.55%	0.00%	6.39%	0.00%
Raymond James Financial Inc	RJF	211.91	103.77	21,990.00		1.62%			
Ralph Lauren Corp	RL	40.39	123.30	4,979.59	0.02%	2.43%	0.00%	10.38%	0.00%
ResMed Inc	RMD	146.93	218.50	32,104.42		0.81%			
Rockwell Automation Inc	ROK	114.88	329.45	37,845.57	0.14%	1.43%	0.00%	18.98%	0.03%
Rollins Inc	ROL	492.79	42.83	21,106.07		1.21%			
Roper Technologies Inc	ROP	106.59	480.80	51,249.43		0.57%		-4.00%	
Ross Stores Inc	ROST	340.66	112.13	38,197.76	0.14%	1.20%	0.00%	10.00%	0.01%
Republic Services Inc	RSG	316.28	153.17	48,444.91	0.17%	1.29%	0.00%	9.09%	0.02%
Raytheon Technologies Corp	RTX	1,461.14	97.96	143,133.47	0.52%	2.41%	0.01%	7.75%	0.04%
Revvity Inc	RVTY	125.44	118.79	14,901.14		0.24%		-6.17%	
SBA Communications Corp	SBAC	108.34	231.76	25,108.65		1.47%			
Starbucks Corp	SBUX	1,146.40	99.06	113,562.38	0.41%	2.14%	0.01%	17.81%	0.07%
Charles Schwab Corp/The	SCHW	1,769.14	56.68	100,274.97	0.36%	1.76%	0.01%	4.46%	0.02%
SolarEdge Technologies Inc	SEDG	56.35	269.05	15,159.62				36.57%	
Sealed Air Corp	SEE	144.39	40.00	5,775.44	0.02%	2.00%	0.00%	4.69%	0.00%
Sherwin-Williams Co/The	SHW	257.89	265.52	68,474.95	0.25%	0.91%	0.00%	9.96%	0.02%
J M Smucker Co/The	SJM	102.05	147.67	15,069.28	0.05%	2.76%	0.00%	5.08%	0.00%
Schlumberger NV	SLB	1,425.33	49.12	70,012.26		2.04%		35.06%	
Snap-on Inc	SNA	52.93	288.19	15,254.47	0.06%	2.25%	0.00%	4.64%	0.00%
Synopsys Inc	SNPS	152.16	435.41	66,251.99	0.24%			16.62%	0.04%
Southern Co/The	SO	1,091.52	70.25	76,678.93	0.28%	3.99%	0.01%	4.50%	0.01%
Simon Property Group Inc	SPG	326.99	115.48	37,760.57	0.14%	6.41%	0.01%	3.45%	0.00%
S&P Global Inc	SPGI	320.80	400.89	128,605.51	0.46%	0.90%	0.00%	13.95%	0.06%
Sempra Energy	SRE	314.65	144.40	45,435.46	0.16%	3.30%	0.01%	3.30%	0.01%
STERIS PLC	STE	98.65	224.98	22,194.50		0.84%			
Steel Dynamics Inc	STLD	169.03	108.93	18,412.87		1.56%		-16.11%	
State Street Corp	STT	334.26	73.18	24,461.07	0.09%	3.44%	0.00%	8.33%	0.01%
Seagate Technology Holdings PLC	STX	207.08	61.87	12,812.16		4.53%		-4.90%	
Constellation Brands Inc	STZ	183.30	246.13	45,115.88	0.16%	1.45%	0.00%	9.59%	0.02%
Stanley Black & Decker Inc	SWK	153.14	93.71	14,351.03		3.41%			
Skyworks Solutions Inc	SWKS	159.16	110.69	17,616.87	0.06%	2.24%	0.00%	9.40%	0.01%
Synchrony Financial	SYF	428.57	33.92	14,537.13		2.71%		64.00%	
Stryker Corp	SYK	379.61	305.09	115,814.60	0.42%	0.98%	0.00%	8.82%	0.04%
Sysco Corp	SYY	506.68	74.20	37,595.80		2.70%		46.00%	
AT&T Inc	T	7,149.00	15.95	114,026.55	0.41%	6.96%	0.03%	3.36%	0.01%
Molson Coors Beverage Co	TAP	200.38	65.84	13,193.28	0.05%	2.49%	0.00%	6.30%	0.00%
TransDigm Group Inc	TDG	54.93	894.17	49,114.97				24.54%	
Teledyne Technologies Inc	TDY	47.05	411.11	19,341.08	0.07%			6.47%	0.00%
Bio-Techne Corp	TECH	157.44	81.63	12,851.58		0.39%			
TE Connectivity Ltd	TEL	315.12	140.16	44,166.52	0.16%	1.68%	0.00%	2.84%	0.00%
Teradyne Inc	TER	155.04	111.33	17,260.49	0.06%	0.40%	0.00%	7.28%	0.00%
Truist Financial Corp	TFC	1,331.92	30.35	40,423.71	0.15%	6.85%	0.01%	6.39%	0.01%
Teleflex Inc	TFX	46.97	242.03	11,368.63	0.04%	0.56%	0.00%	6.15%	0.00%
Target Corp	TGT	461.56	131.90	60,879.76	0.22%	3.34%	0.01%	8.91%	0.02%
TJX Cos Inc/The	TJX	1,149.24	84.79	97,443.89	0.35%	1.57%	0.01%	10.00%	0.04%
Thermo Fisher Scientific Inc	TMO	385.72	521.75	201,249.93		0.27%			
T-Mobile US Inc	TMUS	1,199.89	138.90	166,665.00					
Tapestry Inc	TPR	231.80	42.80	9,920.95	0.04%	2.80%	0.00%	14.00%	0.01%
Targa Resources Corp	TRGP	226.02	76.10	17,200.05		2.63%			
Trimble Inc	TRMB	247.75	52.94	13,115.73					
T Rowe Price Group Inc	TROW	224.57	112.02	25,156.56		4.36%		-8.38%	
Travelers Cos Inc/The	TRV	230.98	173.66	40,111.47	0.14%	2.30%	0.00%	15.79%	0.02%
Tractor Supply Co	TSCO	109.57	221.10	24,225.48	0.09%	1.86%	0.00%	10.28%	0.01%
Tesla Inc	TSLA	3,169.50	261.77	829,681.06					
Tyson Foods Inc	TSN	285.60	51.04	14,577.02		3.76%		-17.96%	
Trane Technologies PLC	TT	228.05	191.26	43,617.23	0.16%	1.57%	0.00%	10.10%	0.02%
Take-Two Interactive Software Inc	TTWO	169.33	147.16	24,919.19	0.09%			6.51%	0.01%
Texas Instruments Inc	TXN	907.65	180.02	163,395.87	0.59%	2.76%	0.02%	10.00%	0.06%
Textron Inc	TXT	201.68	67.63	13,639.62	0.05%	0.12%	0.00%	11.18%	0.01%
Tyler Technologies Inc	TYL	41.93	416.47	17,460.50	0.06%			12.00%	0.01%

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.64%
[2] Estimate of the S&P 500 Growth Rate	10.95%
[3] S&P 500 Estimated Required Market Return	12.68%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
United Airlines Holdings Inc	UAL	326.73	54.87	17,927.62				67.35%	
UDR Inc	UDR	329.17	42.96	14,141.27	0.05%	3.91%	0.00%	7.75%	0.00%
Universal Health Services Inc	UHS	62.93	157.77	9,928.31	0.04%	0.51%	0.00%	9.01%	0.00%
Ulta Beauty Inc	ULTA	49.80	470.60	23,436.57	0.08%			6.09%	0.01%
UnitedHealth Group Inc	UNH	931.03	480.64	447,491.22	1.61%	1.56%	0.03%	13.02%	0.21%
Union Pacific Corp	UNP	609.70	204.62	124,755.79	0.45%	2.54%	0.01%	7.00%	0.03%
United Parcel Service Inc	UPS	724.78	179.25	129,916.82	0.47%	3.62%	0.02%	0.89%	0.00%
United Rentals Inc	URI	68.73	445.37	30,610.73		1.33%		21.23%	
US Bancorp	USB	1,532.92	33.04	50,647.71	0.18%	5.81%	0.01%	9.00%	0.02%
Visa Inc	V	1,618.22	237.48	384,295.60	1.39%	0.76%	0.01%	17.96%	0.25%
VF Corp	VFC	388.68	19.09	7,419.84		6.29%		-1.94%	
VICI Properties Inc	VICI	1,004.24	31.43	31,563.20	0.11%	4.96%	0.01%	6.48%	0.01%
Valero Energy Corp	VLO	361.52	117.30	42,405.94		3.48%		-7.69%	
Vulcan Materials Co	VMC	133.06	225.44	29,996.82		0.76%		20.76%	
Verisk Analytics Inc	VRSK	144.79	226.03	32,727.11	0.12%	0.60%	0.00%	11.71%	0.01%
VeriSign Inc	VRSN	104.10	225.97	23,522.57					
Vertex Pharmaceuticals Inc	VRTX	257.55	351.91	90,635.12	0.33%			13.23%	0.04%
Ventas Inc	VTR	400.05	47.27	18,910.46	0.07%	3.81%	0.00%	9.48%	0.01%
Viatris Inc	VTRS	1,199.03	9.98	11,966.32		4.81%		-1.16%	
Verizon Communications Inc	VZ	4,203.99	37.19	156,346.43		7.02%			
Westinghouse Air Brake Technologies Corp	WAB	179.87	109.67	19,726.34	0.07%	0.62%	0.00%	12.04%	0.01%
Waters Corp	WAT	59.03	266.54	15,734.92	0.06%			7.04%	0.00%
Walgreens Boots Alliance Inc	WBA	863.26	28.49	24,594.31		6.74%		-6.57%	
Warner Bros Discovery Inc	WBD	2,436.11	12.54	30,548.78					
Western Digital Corp	WDC	319.94	37.93	12,135.21				-11.96%	
WEC Energy Group Inc	WEC	315.44	88.24	27,833.98	0.10%	3.54%	0.00%	6.26%	0.01%
Welltower Inc	WELL	497.03	80.89	40,204.84	0.14%	3.02%	0.00%	10.64%	0.02%
Wells Fargo & Co	WFC	3,752.22	42.68	160,144.92	0.58%	2.81%	0.02%	13.41%	0.08%
Whirlpool Corp	WHR	54.76	148.79	8,147.44	0.03%	4.70%	0.00%	7.83%	0.00%
Waste Management Inc	WM	406.77	173.42	70,541.53	0.25%	1.61%	0.00%	10.20%	0.03%
Williams Cos Inc/The	WMB	1,218.19	32.63	39,749.44	0.14%	5.49%	0.01%	3.50%	0.01%
Walmart Inc	WMT	2,692.84	157.18	423,259.81	1.53%	1.45%	0.02%	8.00%	0.12%
W R Berkley Corp	WRB	260.78	59.56	15,531.76	0.06%	0.74%	0.00%	9.00%	0.01%
Westrock Co	WRK	256.13	29.07	7,445.70		3.78%		-20.63%	
West Pharmaceutical Services Inc	WST	74.24	382.47	28,395.72	0.10%	0.20%	0.00%	16.70%	0.02%
Willis Towers Watson PLC	WTW	106.41	235.50	25,060.26	0.09%	1.43%	0.00%	13.01%	0.01%
Weyerhaeuser Co	WY	732.30	33.51	24,539.24		2.27%			
Wynn Resorts Ltd	WYNN	113.80	105.61	12,018.21		0.95%		154.58%	
Xcel Energy Inc	XEL	550.36	62.17	34,215.63	0.12%	3.35%	0.00%	6.30%	0.01%
Exxon Mobil Corp	XOM	4,042.99	107.25	433,610.14		3.39%		32.66%	
DENTSPLY SIRONA Inc	XRAY	212.48	40.02	8,503.37	0.03%	1.40%	0.00%	9.14%	0.00%
Xylem Inc/NY	XYL	239.35	112.62	26,956.05		1.17%			
Yum! Brands Inc	YUM	280.09	138.55	38,806.05	0.14%	1.75%	0.00%	11.71%	0.02%
Zimmer Biomet Holdings Inc	ZBH	208.57	145.60	30,367.65	0.11%	0.66%	0.00%	9.20%	0.01%
Zebra Technologies Corp	ZBRA	51.43	295.83	15,214.54					
Zions Bancorp NA	ZION	148.10	26.86	3,977.99		6.11%		-6.97%	
Zoetis Inc	ZTS	462.11	172.21	79,580.31	0.29%	0.87%	0.00%	10.91%	0.03%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of June 30, 2023
[5] Source: Bloomberg Professional as of June 30, 2023
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional as of June 30, 2023
[9] Equals [7] x [8]
[10] Source: Bloomberg, as of June 30, 2023
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.923140
R Square	0.852188
Adjusted R Square	0.850956
Standard Error	0.003939
Observations	122

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010737	0.010737	691.840633	0.000000
Residual	120	0.001862	0.000016		
Total	121	0.012599			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0849	0.0010	81.33	0.00000	0.08285	0.08698	0.08285	0.08698
U.S. Govt. 30-year Treasury	(0.5753)	0.0219	(26.30)	0.00000	(0.61856)	(0.53195)	(0.61856)	(0.53195)

	U.S. Govt. 30-year Treasury	Risk Premium	Cost of Equity
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.89%	6.25%	10.14%
Blue Chip Near-Term Projected Forecast (Q4 2023 - Q4 2024) [5]	3.84%	6.28%	10.12%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	3.80%	6.31%	10.11%
AVERAGE			10.12%

Notes:
[1] Source: Regulatory Research Associates, rate cases through June 30, 2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of June 30, 2023
[5] Source: Blue Chip Financial Forecasts, Vol. 42, No. 7, June 30, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 42, No. 6, June 1, 2023, at 14.
[7] See notes [4], [5] & [6]
[8] Equals 0.084917 + (-0.575254 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
AVERAGE	10.40%	4.49%	5.91%
MEDIAN	10.29%	4.52%	5.94%

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
Atmos Energy Corporation	ATO	16.76	1.64
NiSource Inc.	NI	11.21	1.83
Northwest Natural Gas Company	NWN	1.55	1.24
ONE Gas Inc.	OGS	4.41	1.66
Spire, Inc.	SR	3.42	1.25
Median		4.41	1.64

Montana-Dakota		
Test Year Rate Base ($millions)	[3]	$ 77.11
Company Proposed Common Equity Ratio	[4]	50.39%
Implied Common Equity ($millions)	[5]	$ 38.86
Implied Market Capitalization ($millions)	[6]	$ 63.81
Market Capitalization of Proxy Group (median) ($millions)	[7]	$ 4,410.83
In % of Proxy Group Market Capitalization (median)	[8]	1.45%

Kroll Cost of Capital Navigator -- Size Premium

		[9]	[10]
Breakdown of Deciles 1-10		Market Capitalization of Largest Company ($ millions)	Size Premium
1-Largest		$ 2,203,381.29	-0.26%
2		$ 31,316.51	0.45%
3		$ 12,323.85	0.57%
4		$ 5,916.02	0.58%
5		$ 3,769.88	0.93%
6		$ 2,365.08	1.16%
7		$ 1,389.12	1.37%
8		$ 782.38	1.18%
9		$ 373.88	2.15%
10-Smallest		$ 218.23	4.83%
Montana-Dakota Implied Market Capitalization	[6]	$ 63.81	4.83%
Proxy Group Market Capitalization (median)	[7]	$ 4,410.83	0.58%
Size Premium	[11]		4.25%

Notes:
[1]-[2] S&P Capital IQ Pro, equals 30-day average as of June 30, 2023
[3] Data provided by the Company
[4] Data provided by the Company
[5] Equals [3] x [4]
[6] Equals [5] x median market-to-book ratio of proxy group
[7] Equals median market capitalization of proxy group x 1000
[8] Equals [6] / [7]
[9]-[10] Kroll Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2022
[11] Size Premium of Montana-Dakota less Size Premium of Proxy Group

FLOTATION COST ADJUSTMENT

Company	Ticker	[1] Date [i]	[2] Shares Issued (000)	[3] Offering Price	[4] Under-writing Discount [ii]	[5] Offering Expense ($000)	[6] Net Proceeds Per Share	[7] Total Flotation Costs ($000)	[8] Gross Equity Issue Before Costs ($000)	[9] Net Proceeds ($000)	[10] Flotation Cost Percentage
MDU Resources Group	MDU	2/4/2004	2,300	23.32	0.793	350	22.37	2,174	53,636	51,462	4.05%
MDU Resources Group	MDU	11/19/2002	2,400	24.00	0.720	193	23.20	1,921	57,600	55,680	3.33%
Total								$ 4,094.40	$ 111,236.00	$ 107,141.60	
								WEIGHTED AVERAGE FLOTATION COSTS			3.681%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount is calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[11] Annualized Dividend	[12] Stock Price	[13] Dividend Yield	[14] Expected Dividend Yield	[15] Expected Dividend Yield Adjusted for Flotation Costs	[16] Value Line Earnings Growth	[17] Yahoo! Finance Earnings Growth	[18] Zacks Earnings Growth	[19] Average Earnings Growth	[20] Cost of Equity: Mean Growth Rate	[21] Cost of Equity Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$2.96	$115.97	2.55%	2.65%	2.75%	7.00%	7.80%	7.50%	7.43%	10.08%	10.18%
NiSource Inc.	NI	$1.00	$27.13	3.69%	3.83%	3.97%	9.50%	6.70%	7.00%	7.73%	11.56%	11.71%
Northwest Natural Gas Company	NWN	$1.94	$43.23	4.49%	4.58%	4.76%	6.50%	2.80%	3.70%	4.33%	8.92%	9.09%
ONE Gas, Inc.	OGS	$2.60	$79.63	3.27%	3.35%	3.48%	6.50%	5.00%	5.00%	5.50%	8.85%	8.98%
Spire, Inc.	SR	$2.88	$64.67	4.45%	4.59%	4.76%	8.00%	n/a	4.20%	6.10%	10.69%	10.86%
Mean											10.02%	10.17%
Median											10.08%	10.18%
Flotation Cost Adjustment (Mean) [22]												0.15%
Flotation Cost Adjustment (Median) [23]												0.10%

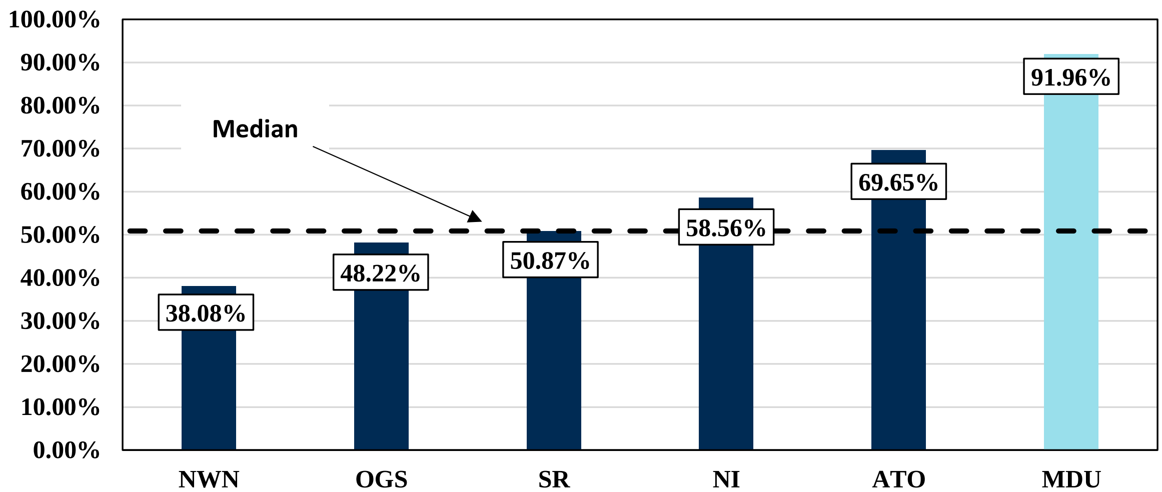
Notes:
[1] - [5] Source: MDU Resources Group - Prospectus dated February 4, 2004 and Prospectus dated November 19, 2002.
[6] Equals [9]/[2]
[7] Equals [5] + ([4] x [2])
[8] Equals [2] x [3]
[9] Equals [8] - [7]
[10] Equals [7] / [8]
[11] Bloomberg Professional
[12] Bloomberg Professional, equals 30-day average as of June 30, 2023
[13] Equals [11] / [12]
[14] Equals [13] x (1 + 0.5 x [19])
[15] Equals [14] / (1 − Flotation Cost)
[16] Value Line
[17] Yahoo! Finance
[18] Zacks Investment Research
[19] Equals Average of [16], [17], [18]
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals [21] (Mean) − [20] (Mean)
[23] Equals [21] (Median) − [20] (Median)

2024-2027 CAPITAL EXPENDITURES AS A PERCENTAGE OF 2022 NET PLANT
($ Millions)

		[1]	[3]	[4]	[5]	[6]	[7]
		2022	2024	2025	2026	2027	2024-2027 Cap. Ex. / 2022 Net Plant
Atmos Energy Corporation	ATO						
Capital Spending per Share			$ 18.55	$ 18.43	$ 18.30	$ 18.30	
Common Shares Outstanding			152.0	161.0	170.0	170.0	
Capital Expenditures			$ 2,819.60	$ 2,966.43	$ 3,111.00	$ 3,111.00	69.65%
Net Plant		$ 17,240					
NiSource Inc.	NI						
Capital Spending per Share			$ 6.45	$ 6.60	$ 6.75	$ 6.75	
Common Shares Outstanding			425.0	435.0	445.0	445.0	
Capital Expenditures			$ 2,741.25	$ 2,871.00	$ 3,003.75	$ 3,003.75	58.56%
Net Plant		$ 19,843					
Northwest Natural Gas Company	NWN						
Capital Spending per Share			$ 7.75	$ 7.63	$ 7.50	$ 7.50	
Common Shares Outstanding			37.5	38.8	40.0	40.0	
Capital Expenditures			$ 290.63	$ 295.47	$ 300.00	$ 300.00	38.08%
Net Plant		$ 3,114					
ONE Gas, Inc.	OGS						
Capital Spending per Share			$ 11.55	$ 11.93	$ 12.30	$ 12.30	
Common Shares Outstanding			55.5	56.3	57.0	57.0	
Capital Expenditures			$ 641.03	$ 670.78	$ 701.10	$ 701.10	48.22%
Net Plant		$ 5,629					
Spire, Inc.	SR						
Capital Spending per Share			$ 13.60	$ 12.80	$ 12.00	$ 12.00	
Common Shares Outstanding			53.0	54.0	55.0	55.0	
Capital Expenditures			$ 720.80	$ 691.20	$ 660.00	$ 660.00	50.87%
Net Plant		$ 5,370					
Montana-Dakota	MDU						
Capital Expenditures [8]			$ 16.73	$ 16.30	$ 16.50	$ 13.18	91.96%
Net Plant [9]		$ 68.19					

Notes:
[1] - [6] Value Line, dated May 26, 2023
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Provided by the Company
[9] Provided by the Company

2024-2027 CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT



Projected CAPEX/2022 Net Plant

	Company	Ticker	Projected CAPEX / 2022 Net Plant
1	Northwest Natural Gas Company	NWN	38.08%
2	ONE Gas, Inc.	OGS	48.22%
3	Spire, Inc.	SR	50.87%
4	NiSource Inc.	NI	58.56%
5	Atmos Energy Corporation	ATO	69.65%
6	**Montana-Dakota**	**MDU**	**91.96%**
	Proxy Group Median		50.87%
	MDU as % of Median		1.81

Notes:
Exhibit No. ___(CMW-2), Schedule 11, p. 1 col. [7]

REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
Atmos Energy Corporation									
	Atmos Energy Corporation	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Louisiana	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Mississippi	Gas	Historical	Partial	Yes	No	Yes	Yes
	Atmos Energy Corporation	Tennessee	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
NiSource Inc.									
	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Partial	No	No	Yes	Yes
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	No	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Historical	Partial	No	No	Yes	Yes
Northwest Natural Gas Company									
	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No
ONE Gas, Inc.									
	Kansas Gas Service Co.	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Partial	Yes	No	Yes	No
	Texas Gas Service Co. Inc.	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
Spire, Inc.									
	Spire Alabama Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Gulf Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Missouri Inc.	Missouri	Gas	Partially Forecast	Partial	No	No	Yes	Yes
Proxy Group Totals			Fully Forecast	8					
			Partially Forecast	3				Yes 19	Yes 15
			Historical	10				No 2	No 6
			% Forecast	52.4%				% Yes 90.5%	% Yes 71.4%
Montana-Dakota [7]		South Dakota	Gas	Partially Forecast	Yes	No	No	Yes	No

Notes:
[1] Regulatory Research Associates, Rate Case History, effective as of June 30, 2023, Company Tariffs, Company Form 10-K.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[3] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[7] Data provided by Montana-Dakota

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
NiSource Inc.	NI	54.17%	54.85%	54.43%	54.48%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
One Gas Inc.	OGS	58.23%	61.09%	60.04%	59.79%
Spire Inc.	SR	47.30%	49.08%	52.75%	49.71%
Proxy Group					
MEAN		53.49%	53.80%	53.49%	53.59%
LOW		47.30%	44.08%	41.92%	44.57%
HIGH		60.01%	61.09%	60.04%	59.79%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	60.01%	59.88%	58.31%	59.40%
Northern Indiana Public Service Company LLC	NI	56.92%	58.59%	58.01%	57.84%
Columbia Gas of Kentucky, Inc.	NI	54.91%	53.87%	54.68%	54.49%
Columbia Gas of Maryland, Inc.	NI	51.96%	55.26%	54.95%	54.06%
Columbia Gas of Ohio, Inc.	NI	50.67%	50.79%	50.45%	50.64%
Columbia Gas of Pennsylvania, Inc.	NI	56.64%	56.05%	55.68%	56.12%
Columbia Gas of Virginia, Inc.	NI	44.25%	44.52%	43.69%	44.15%
Northwest Natural Gas Company	NWN	47.72%	44.08%	41.92%	44.57%
Kansas Gas Service Company, Inc.	OGS	58.37%	61.37%	60.33%	60.02%
Oklahoma Natural Gas Company	OGS		60.99%	59.85%	60.42%
Texas Gas Service Company, Inc.	OGS	58.13%	60.98%	59.99%	59.70%
Spire Alabama Inc.	SR	52.01%	56.67%	58.82%	55.84%
Spire Gulf Inc.	SR	41.35%	41.14%	39.49%	40.66%
Spire Mississippi Inc.	SR		39.18%	38.74%	38.96%
Spire Missouri Inc.	SR	45.49%	46.20%	50.65%	47.45%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.
[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
NiSource Inc.	NI	45.83%	45.15%	45.57%	45.52%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
One Gas Inc.	OGS	41.77%	38.91%	39.96%	40.21%
Spire Inc.	SR	39.78%	39.42%	37.24%	38.82%
Proxy Group					
MEAN		42.56%	41.69%	42.18%	42.15%
LOW		39.78%	38.91%	37.24%	38.82%
HIGH		45.83%	45.15%	46.45%	45.59%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	39.99%	40.12%	41.69%	40.60%
Northern Indiana Public Service Company LLC	NI	43.08%	41.41%	41.99%	42.16%
Columbia Gas of Kentucky, Inc.	NI	45.09%	46.13%	45.32%	45.51%
Columbia Gas of Maryland, Inc.	NI	48.04%	44.74%	45.05%	45.94%
Columbia Gas of Ohio, Inc.	NI	49.33%	49.21%	49.55%	49.36%
Columbia Gas of Pennsylvania, Inc.	NI	43.36%	43.95%	44.32%	43.88%
Columbia Gas of Virginia, Inc.	NI	55.75%	55.48%	56.31%	55.85%
Northwest Natural Gas Company	NWN	45.46%	44.85%	46.45%	45.59%
Kansas Gas Service Company, Inc.	OGS	41.63%	38.63%	39.67%	39.98%
Oklahoma Natural Gas Company	OGS		39.01%	40.15%	39.58%
Texas Gas Service Company, Inc.	OGS	41.87%	39.02%	40.01%	40.30%
Spire Alabama Inc.	SR	33.01%	40.18%	32.80%	35.33%
Spire Gulf Inc.	SR	38.77%	42.00%	57.90%	46.22%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	42.91%	39.42%	38.72%	40.35%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	0.00%	0.00%	0.00%	0.00%
Proxy Group					
MEAN		0.00%	0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%	0.00%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR		0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%	0.00%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

CAPITAL STRUCTURE ANALYSIS

SHORT-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
NiSource Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
One Gas Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Inc.	SR	12.92%	11.49%	10.01%	11.47%
Proxy Group					
MEAN		3.95%	4.51%	4.33%	4.26%
LOW		0.00%	0.00%	0.00%	0.00%
HIGH		12.92%	11.49%	11.63%	11.47%

SHORT-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2022	2021	2020	3-yr Avg.
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%	0.00%
Northern Indiana Public Service Company LLC	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Kentucky, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Maryland, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Ohio, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Pennsylvania, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Columbia Gas of Virginia, Inc.	NI	0.00%	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	6.82%	11.07%	11.63%	9.84%
Kansas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%	0.00%
Texas Gas Service Company, Inc.	OGS	0.00%	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR	14.98%	3.15%	8.38%	8.83%
Spire Gulf Inc.	SR	19.88%	16.86%	2.61%	13.12%
Spire Mississippi Inc.	SR		60.82%	61.26%	61.04%
Spire Missouri Inc.	SR	11.60%	14.38%	10.63%	12.20%

Notes:

[1] Ratios are weighted by actual common capital, preferred equity, long-term debt and short-term debt of Operating Subsidiaries.

[2] Natural Gas, Electric and Water operating subsidiaries where data was unable to be obtained for 2022, 2021 and 2020 were removed from the analysis.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG-23-___

Direct Testimony

Of

Russel Nishikawa

Q. Please state your name and business address.

A. My name is Russel Nishikawa, and my business address is 555 South Cole Road, Boise, Idaho 83709.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Engineering Services for Montana-Dakota Utilities Co. ("Montana-Dakota" or "Company"), Great Plains Natural Gas Co. ("Great Plains"), Cascade Natural Gas Corporation ("Cascade") and Intermountain Gas Company ("Intermountain").

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I have managerial responsibility and oversight for the review, planning, development and design of the Company's pipeline systems and technical facilities.

Q. Please outline your educational and professional background.

A. I am a graduate of University of Idaho with a Bachelor of Science Degree in Mechanical Engineering. I am a licensed professional engineer in the state of Idaho.

I began my career in 2005 as a gas engineer with Intermountain Gas in Boise, ID. I advanced through the Engineering Department until I was promoted to my current managerial position in 2018.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's project selection and budgeting process; and (2) describe and provide an update on construction activities, schedule, and costs estimates for the Town Border Station (TBS) projects located in North Spearfish and Rapid City.

OVERVIEW OF PROJECT SELECTION AND BUDGETING PROCESS

Q. What type of major capital projects does the Company typically perform?

A. The bulk of Montana-Dakota's major capital projects are pipeline replacement projects that have been identified for safety reasons and to reduce risk on Montana-Dakota's system, and system reinforcements or system expansions that have been identified as needed to ensure system reliability and to accommodate growth on the Company's system. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution system enhancements. Distribution system enhancements do not reduce demand, nor do they create additional supply; instead, enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing supply points.

Q. Please provide an overview of Montana-Dakota's identification and selection process for distribution enhancement projects.

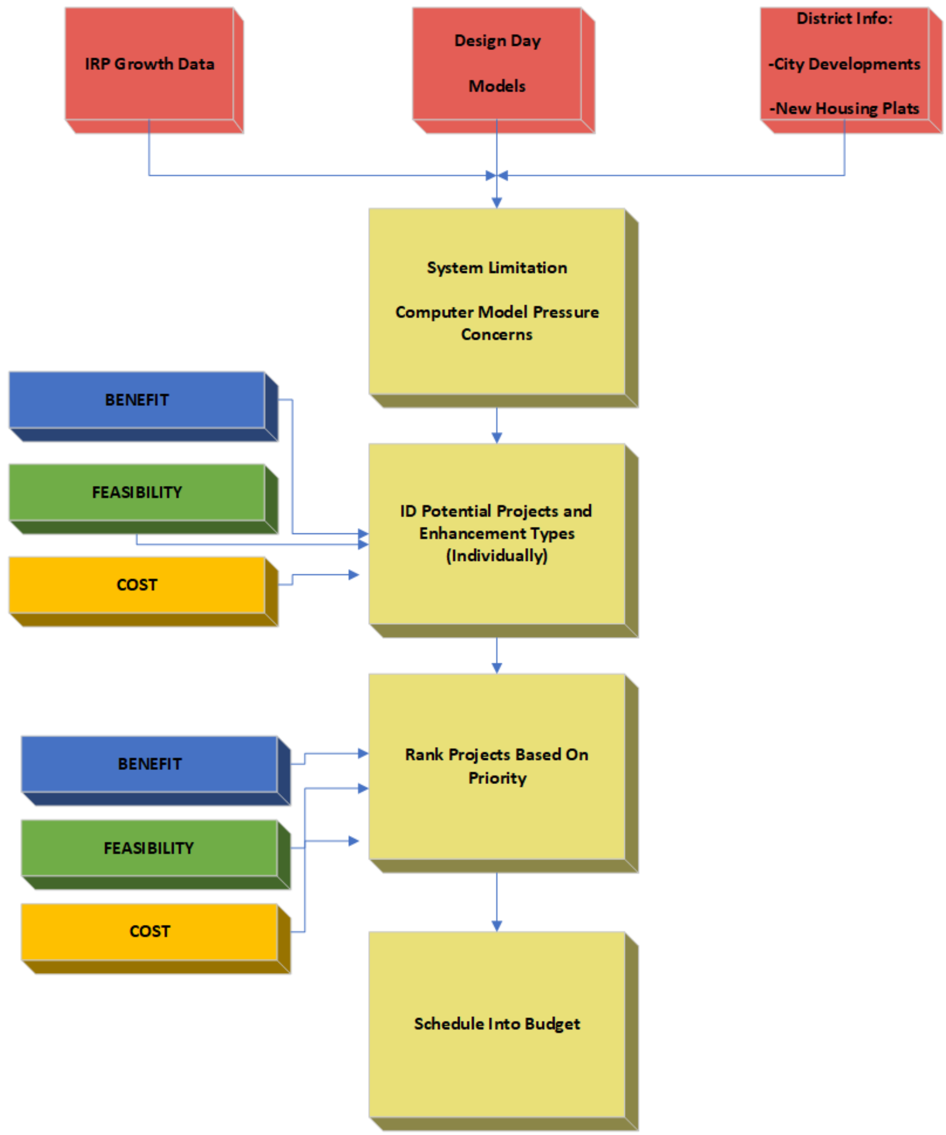
A. The Engineering Department works closely with Energy Services Representatives and district management to ensure the system is safe and reliable. As towns develop and add new homes and businesses, the need for pipeline expansions and/or reinforcements increase. The system expansion projects are historically driven by new city developments or new housing plats. Before expansion projects can be constructed to serve these new customers, an engineering analysis is performed. Using system modeling software to represent cold weather scenarios, predictions can be made about the capacity of the system. As new groups of customers seek natural gas service, the models provide feedback on how best to serve them while maintaining reliable supply to our existing customers.

Another aspect of system planning involves city gate capacity analysis and forecasting. Over time, each gate station will take on more demand and it is Montana-Dakota's objective to stay ahead of potential reliability issues by predicting and identifying constraints on its system. Cold weather design day modeling allows Montana-Dakota to forecast necessary gate upgrades. SCADA communication technology utilized by Montana-Dakota allows verification of models with real time and historic gate flow and pressure data.

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification, and corresponding optimized combinations of pipe modification and pressure modification solutions to maintain adequate pressures throughout the network. After developing a working demand study, the Company analyzes every system at peak cold weather conditions to identify areas where potential outages may occur. These constraint areas are then risk-ranked against each other to ensure the highest risk areas are corrected first and others are properly addressed in time. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient area of the distribution system;
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights-of-way, traffic issues, and minimal to no water, railroad or major highway crossings, etc.;
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods;
- The segment of pipe that provides opportunity to add additional customers; and
- Total construction costs including restoration.

Once a project/reinforcement is identified, the Design Engineer or Energy Services Representative begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of review for the project/reinforcement selection criteria. Figure 1, below, provides a schematic representation of the distribution project process flow.



Q. Please provide an overview of Montana-Dakota's capital budgeting process.

A. Capital additions and changes are planned through the annual budgeting process using PowerPlan ("PP"), an accounting software application. The budget process begins with an individual (originator) creating specific funding projects in PP for all new projects to be included in the five-year capital budget. Originators are generally managers at the district level or engineering staff at the Company level. Sources of information for capital projects include the DIMP, TIMP, state and local government agencies, and internal Montana-Dakota personnel. Funding projects are used to hold the capital budget estimates and will be linked to the capital work orders to be created when actual costs commence. A Fixed Asset Financial Analyst reviews the funding projects for proper setup. If the project is not considered a capital expenditure as it was submitted, it is rejected and sent back to the originator for revision, cancelled, or it is moved to Operations and Maintenance ("O&M") expense. After the review has been completed, the Fixed Asset Financial Analyst will add appropriate overheads. Blanket funding projects are used year after year to budget for high volume mass property work orders typically under $150,000 each.

Once all the funding projects have been updated with expenditures, various Company operating managers generate reports to show estimated expenditures and justification for each project. The managers perform the review of funding projects and see that any necessary changes are made to the estimate and that the project is supported. Reports are then generated by the budgeting personnel for review and approval by the Directors and Vice Presidents of the Utility Group. Any final budget changes are made, and the budgets are then presented to the Utility Group's President for review and approval. The final Utility Group budget is then presented to the MDU Resources CEO for review and approval. If the budget is approved by the MDU Resources CEO, the final review and approval occurs with the Board of Directors. At each stage of the review and approval process a project (or projects) can be challenged for appropriateness and removed from the capital budget or moved to another year within the five-year budget. The addition or removal of projects can also be impacted by other factors such as available capital and/or borrowing capacity, upon appropriate review to verify continued reliable and safe service.

After final approval, an approved budget version is created in PP, locked for entry and the funding projects and estimated amounts in the approved budget version are copied back to the working budget version. Project managers are notified that the budget has been approved and the funding projects are open for work order creation. Projects are monitored and updated throughout the year as part of the review process and to insure, as best as possible, that projects are completed on time and within the approved budget.

Q. Have there been any changes to these processes since the Company's last rate case?

A. Yes. Beginning in January 2019, the Company's parent, MDU Resources has moved toward a "one utility" model. As a result, the engineering department was reorganized, and more consistent tasks and processes were defined. Within this effort there is a new internal requirement to develop a more robust analysis for any project with a cost estimate over $1 million dollars. As part of that analysis the Company develops documentation supporting the project, including a substantial executive summary, Synergi model snapshots, alternatives considered, and timing and justification. The Engineering Managers and Directors collaboratively review all projects and determine which are the most important from a risk standpoint and what the timing of the projects should be to best mitigate risks.

Q. For work that will be performed in 2023, how does the Company develop budgeted amounts?

A. The Company's capital budgets were developed in June 2022, and the Company expects that its actual investment should not differ materially from the budgeted amounts for the projects that are not yet complete. Currently, Montana-Dakota is not aware of any immediate impacts to the construction schedules for its capital projects. The Company will provide updates regarding changes to budgeted amounts or actual investments, and any relevant changes in schedule, through discovery (as requested).

MAJOR CAPITAL PROJECTS

Q. Would you please describe the North Spearfish and Rapid City TBS Projects?

A. Yes. The following pages contain a description of each project, including the need for each project.

Q. How will the Company's customers benefit from the projects?

A. The benefits of the projects are increased distribution system capacity and reliability, allowing the Company to provide consistent service to our current and future customers.

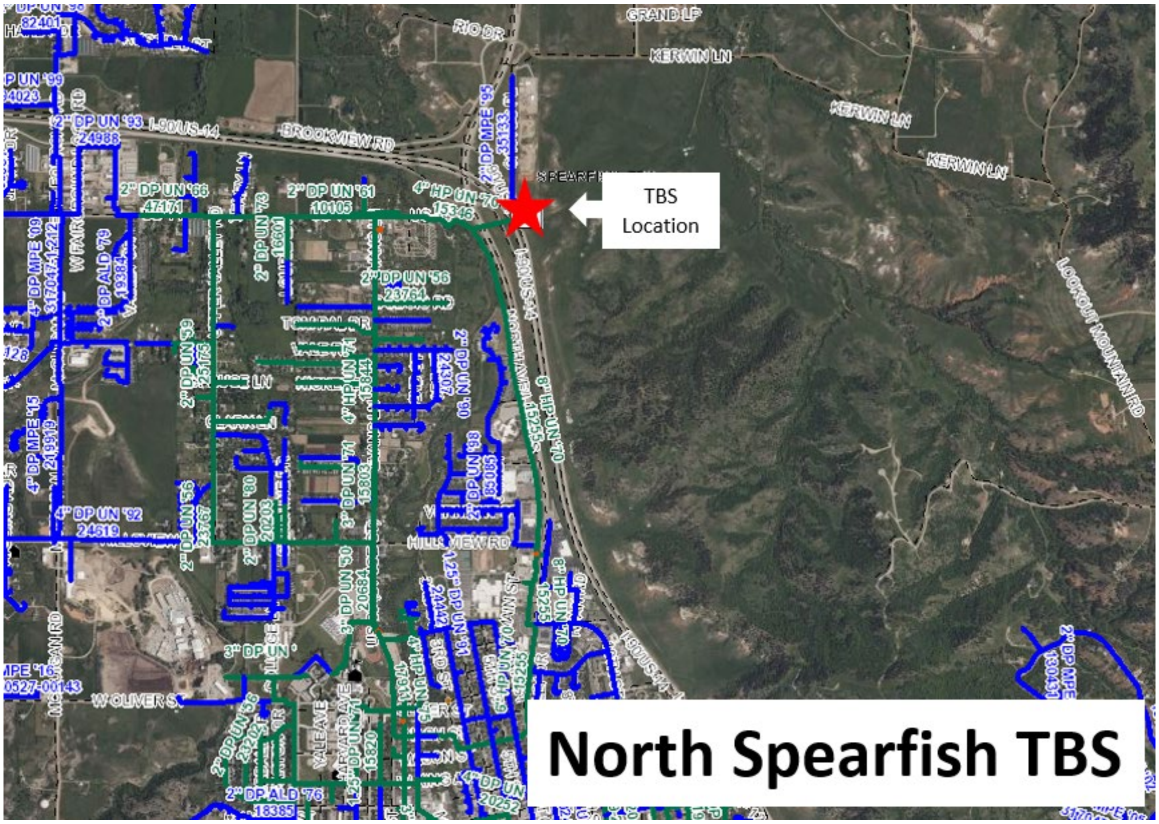
Q. Did the Company consider alternative ways or timeframes to meet the need for these projects?

A. No alternatives were identified. The North Spearfish and Rapid City TBS are a key supply into their respective distribution systems and are necessary to provide reliable service.

North Spearfish TBS Project

Q. Please describe the North Spearfish TBS Project.

A. The North Spearfish TBS project increased available flow capacity through WBI infrastructure and involved the Company installation of new pressure regulation facilities and communication systems.



Q. Why did the Company undertake the North Spearfish TBS Project?

A. The North Spearfish TBS project was constructed to increase deliverability capacity from WBI, the interstate pipeline supplier. WBI's current Spearfish delivery capacity was undersized for expected demand.

Q. What work has been performed in prior phases of the project?

A. The North Spearfish TBS Project is a one-year project started and completed in 2023, there were no prior phases.

Q. What is the timing of the North Spearfish TBS Project?

A. The project was started in spring of 2023 and is scheduled for completion by the end of 2023.

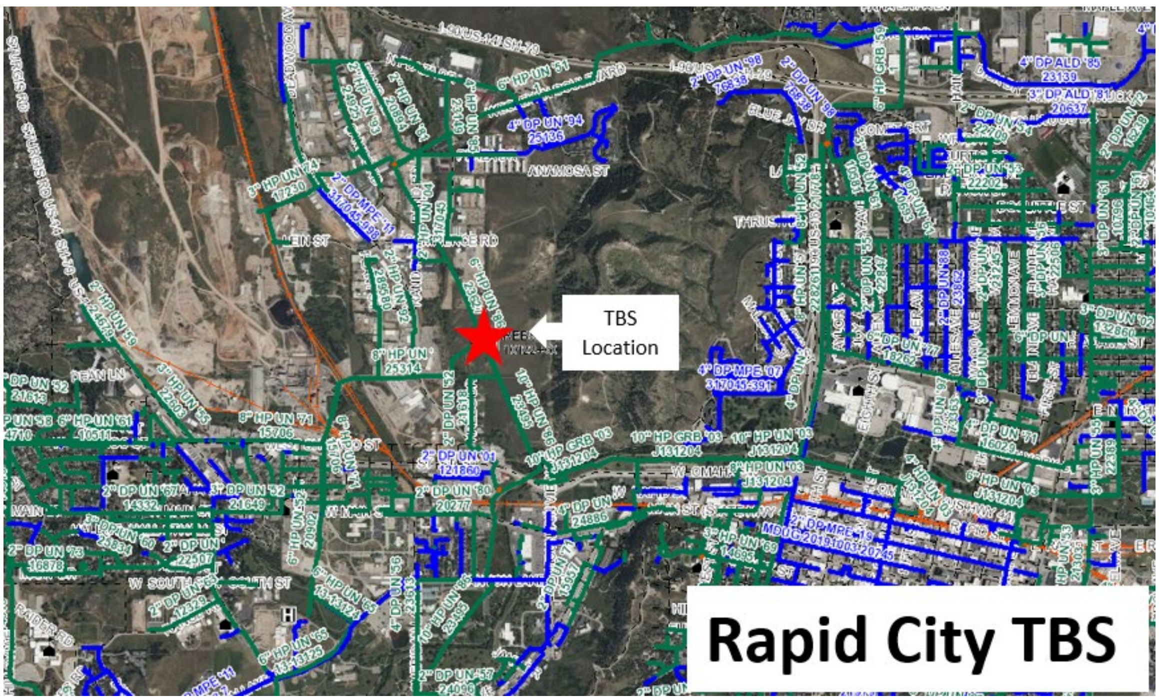
Q. What were the capital cost estimates of the project?

A. The current capital cost is $1,072,109 as shown on Rule 20:10:13:56, Statement D, Schedule D-2 page 3 as FP-319939.

Rapid City TBS Upgrade

Q. Please describe the Rapid City TBS Upgrade project.

A. The Rapid City TBS Upgrade project increases available flow capacity through WBI infrastructure and involved the Company installation of new pressure regulation facilities and communication systems.



Q. Why did the Company undertake the Rapid City TBS Upgrade?

A. The Rapid City TBS Upgrade project was constructed to increase deliverability capacity from WBI. WBI's current Rapid City delivery capacity was undersized for forecasted demand, and timing aligned with WBI's Line 15 Expansion Project.

Q. What work has been performed in prior phases of the project?

A. The Rapid City TBS Upgrade project was a one-year project started and completed in 2023, there were no prior phases.

Q. What is the timing of the Rapid City TBS Upgrade?

A. The project was started in spring of 2023 and is scheduled for completion by the end of 2023.

Q. What were the capital cost estimates of the project?

A. The current capital cost is $1,432,790 and is shown on Rule 20:10:13:56, Statement D, Schedule D-2 page 3 as FP-323145.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-___

Direct Testimony

Of

Jesse Volk

Q. Please state your name and business address.

A. My name is Jesse Volk, and my business address is 705 West Fir Avenue, Fergus Falls, Minnesota 56537.

Q. By whom are you employed and in what capacity?

A. I am the System Integrity Manager for Montana-Dakota Utilities Co. (“Montana-Dakota” or “Company”), Great Plains Natural Gas Co. (“Great Plains”), Cascade Natural Gas Corporation (“Cascade”), and Intermountain Gas Company (“Intermountain”).

Q. Please describe your duties and responsibilities with Montana-Dakota.

A. I am responsible for the management of the Transmission and Distribution Integrity Management programs and Integrity Replacement projects, which include the System Safety and Integrity Program (SSIP).

Q. Please outline your educational and professional background.

A. I am a graduate of South Dakota School of Mines and Technology with a Bachelor of Science Degree in Civil Engineering. I am also a registered professional engineer with the State of North Dakota.

I began my career in 2007 as a gas engineer with Montana-Dakota in Dickinson, North Dakota. Since that time, I have held various positions of increasing responsibilities throughout the gas operations and engineering departments across the eight states of Idaho, Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington, and Wyoming.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes, I have testified before the Minnesota Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's System Safety and Integrity Program (SSIP); and (2) provide an overview of the Company's SSIP projects that were completed since the last rate case and those currently in progress.

<u>OVERVIEW OF SYSTEM SAFETY AND INTEGRITY PROGRAM</u>

Q. What is Montana-Dakota's System Safety and Integrity Program (SSIP)?

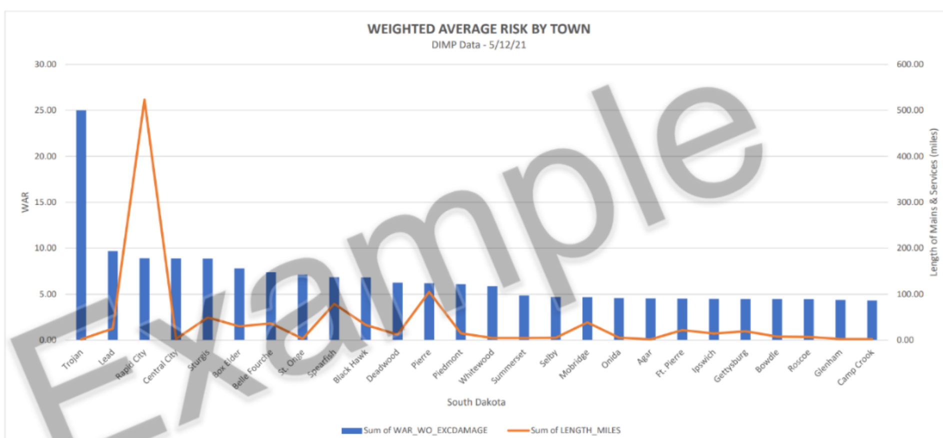
A. Montana-Dakota's SSIP is a pipeline replacement program that accounts for a substantial portion of the Company's natural gas distribution projects. The replacements are a direct result of the Integrity Management Program (IMP) mandated by the Pipeline and Hazardous Materials Safety Administration (PHMSA). IMP requires pipeline operators to implement a comprehensive and cost-effective process that analyzes pipelines through all stages, including engineering, design, construction, operation, inspection, repairs, and replacement.

Q. How does the Company prioritize and select safety-related projects?

A. Montana-Dakota's Distribution Integrity Management Program (DIMP) assigns weightings and consequence factors to each pipeline segment based on attributes and key IMP threats. The data is analyzed through the System Safety Integrity Program (SSIP) which identifies and prioritizes Montana-Dakota's highest risk systems by state, based on the Weighted Average Risk (WAR) scores of Early Vintage Steel Pipe (EVSP) and Early Vintage Plastic Pipe (EVPP) as shown below.

SOUTH DAKOTA – 2021 SSIP PLAN

Town Name	WAR[1]	Length (miles)
Trojan	24.99	1.95
Lead	9.69	25.45
Rapid City	8.90	523.07
Central City	8.88	2.97
Sturgis	8.87	49.52
Box Elder	7.81	29.97
Belle Fourche	7.39	36.72
St. Onge	7.16	3.20
Spearfish	6.85	79.14
Black Hawk	6.83	33.15
Deadwood	6.27	12.22
Pierre	6.19	105.33
Piedmont	6.09	15.00
Whitewood	5.89	4.80
Summerset	4.86	4.74
Selby	4.69	5.33
Mobridge	4.67	38.61
Onida	4.60	5.49
Agar	4.55	1.87
Ft. Pierre	4.52	21.98
Ipswich	4.49	14.57
Gettysburg	4.48	19.54
Bowdle	4.48	7.72
Roscoe	4.47	7.19
Glenham	4.39	2.51
Camp Crook	4.31	2.54
SD Totals	**7.74**	**1054.58**



Notes: 1. Weighted Average Risk scores are for Early Vintage Steel Pipe (EVSP) & Early Vintage Plastic Pipe (EVPP). Excludes risk due to Excavation Damage.

Five Year Replacement Plan (2021-2025)		
Year	Town	Comment
2021-2024	Lead/Trojan	In year 2 of 5-year plan
2025	Rapid City	Year 1 of multi-year project

Q. What types of projects are typically performed to address safety-related concerns?

A. Pipeline replacement is typically the most viable option to remediate risks associated with corrosion, material, weld/joint, equipment failure, incorrect operation, natural forces, outside forces, and missing data threats. If Montana-Dakota determines that replacement is an appropriate action to reduce the risk, the Company establishes a replacement project.

Q. Does the Company consider alternative ways or timeframes to meet the need for this project?

A. When feasible, Montana-Dakota works jointly with State, City, County, or general contractors performing highway, road, and underground infrastructure replacement projects within the same vicinity. This collaboration ultimately eliminates duplication of work, provides cost savings, and limits long-term interruptions to the public and Montana-Dakota's customers.

Q. How will the Company's customers benefit from the project?

A. Montana-Dakota's SSIP replaces and eliminates early vintage steel and plastic pipelines prone to bare or poor coating, industry documented Aldyl-a plastic defects, unknown attributes, missing data, mechanical fittings, inside gas meters, and non-reported third-party damages. The Company's replacement of these high-risk systems ultimately increases overall public safety, lowers operating and maintenance (O&M) costs, and improves system reliability for Montana-Dakota's customers.

Q. Would you please describe the major capital projects that have been completed since the last rate case and the projects that are currently underway?

A. Yes. The following pages contain a description of each project, including the need for each project.

<u>MAJOR CAPITAL PROJECTS</u>

<u>2018 - Belle Fourche SSIP Project</u>

Q. Would you please describe the Belle Fourche SSIP project?

A. The Belle Fourche SSIP project replaced Low Pressure Early Vintage Steel Pipe (EVSP) natural gas mains and services with medium and high-density polyethylene (MDPE & HDPE) lines. Project replacement quantities and type are as follows:

<u>Mains</u>

2" MDPE – 11,250 feet

4" MDPE – 1,245 feet

6" HDPE – 7,500 feet

<u>Services</u>

Service line quantity replaced or re-tested – 290

<u>District Regulator Stations (DRS)</u>

DRS Retired - 1

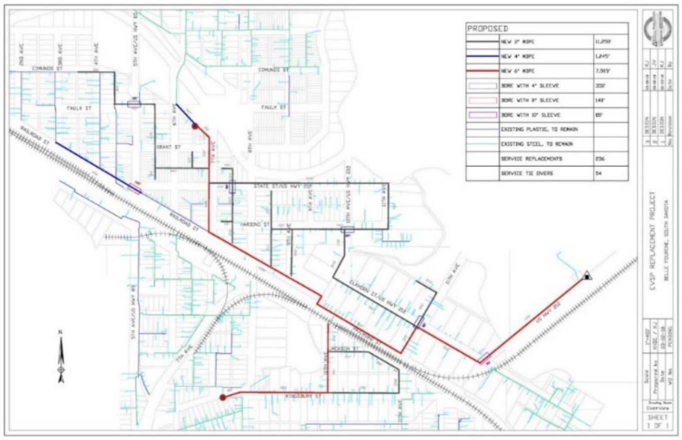


Figure 1 – Belle Fourche

Q. **Why did the Company undertake the Belle Fourche Replacement?**

A. Belle Fourche was identified in 2018 as Montana-Dakota's highest risk EVSP and EVPP natural gas system in the state of South Dakota by the Company's SSIP.

Figure 3 – Belle Fourche DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Belle Fourche SSIP project was started and completed in 2018.

Q. What are the costs of the project?

A. Project costs are as follows:

Main Replacements - $979,010

Service Replacements - $758,578

<u>2019 – Rapid City SSIP</u>

Q. Would you please describe the Rapid City SSIP project?

A. The Rapid City SSIP project replaced Low Pressure Early Vintage Steel Pipe (EVSP) and Early Vintage Plastic Pipe (EVPP) natural gas mains and services with medium density polyethylene (MDPE) line. Project replacement quantities and type are as follows:

<u>Mains</u>

2” MDPE – 10,450 feet

4” MDPE – 1,923 feet

<u>Services</u>

Service line quantity replaced or re-tested - 168

<u>District Regulator Stations (DRS)</u>

DRS Retired - 4

PROPOSED - PROJECT TOTALS									
DESCRIPTION	UNIT	PH 1	PH 2	PH 3	PH4	PH 5	PH 6	PH 7	TOTAL
2" PE MAIN	LF	411	1015	1758	1979	2143	0	3144	10450
4" PE MAIN	LF	834	0	0	0	334	755	0	1923
SERVICE REPLACEMENT (APPROX.)	EA	25	17	20	50	16	1	36	165
SERVICE TIE-OVER (APPROX.)	EA	0	0	0	1	2	0	0	3
ALT#1: METER TIE-OVER	EA	34	20	25	93	23	2	62	259
ALT#2: REMOVE GREASEABLE PLUG VALVES*	EA	2	0	7	9	4	0	7	29

*THE VALVE ON THE IP MAIN AT KANSAS CITY & 8TH ST MUST ALSO BE REMOVED AFTER THE IP LATERAL IS RETIRED

Figure 4 – Rapid City

Q. Why did the Company undertake the Rapid City Replacement?

A. Rapid City was identified in 2019 as Montana-Dakota's highest risk EVSP and EVPP natural gas distribution system in the state of South Dakota by the SSIP. Rapid City was also the only remaining Low Pressure (LP) distribution system in the Company's South Dakota service territory.

Figure 6 – Rapid City DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Rapid City SSIP project was started and completed in 2019.

Q6. What are the costs of the project?

A. Project costs are as follows:

Main Replacements - $1,864,278

Service Replacements - $1,181,540

2020 & 2021 – Trojan/Lead SSIP

Q. Would you please describe the Trojan & Lead SSIP project?

A. The Trojan/Lead SSIP project replaced High Pressure EVSP and EVPP natural gas mains and services with HDPE line. The multi-year replacement consisted of the following:

Main (2020)

2" HDPE – 5,600 feet

Services (2020)

Service line quantity replaced or re-tested - 9

District Regulator Stations (DRS) (2020)

DRS Retired - 1

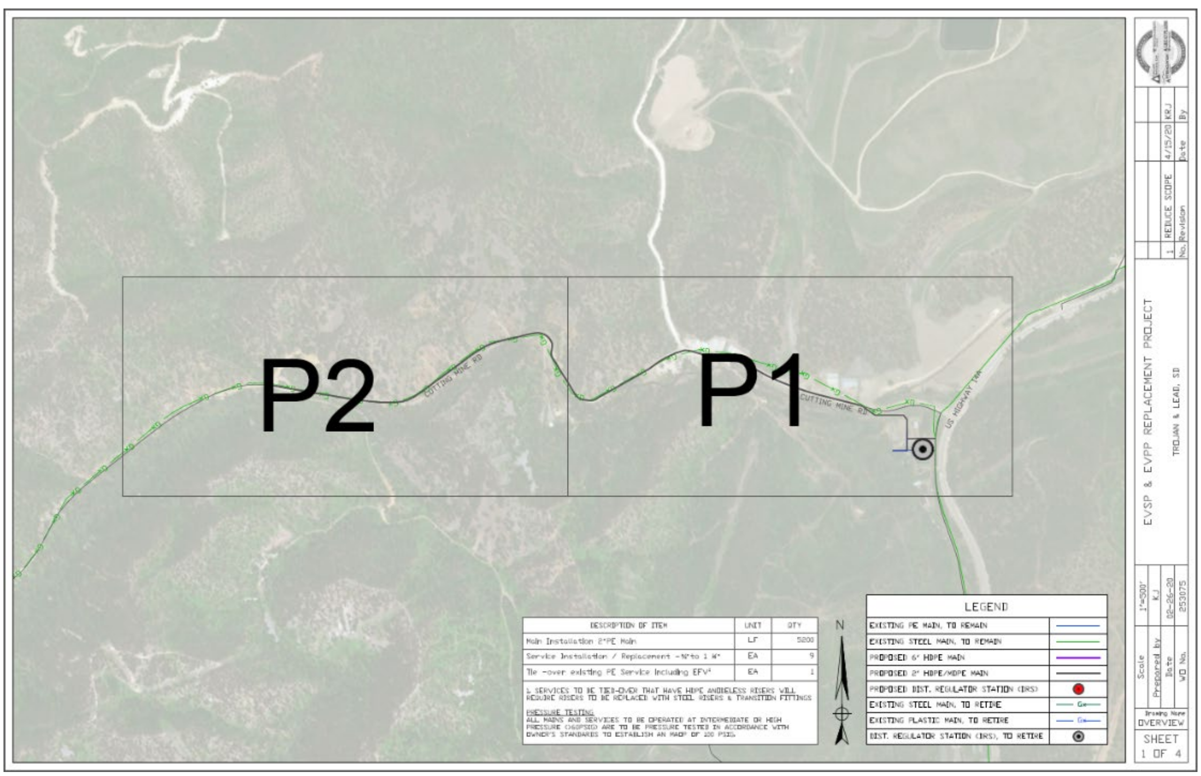


Figure 7 – Trojan/Lead (2021)

Main (2021)

2” HDPE – 220 feet

4” HDPE – 40 feet

6” HDPE – 35,000 feet

Services (2021)

Service line quantity replaced or re-tested - 18

District Regulator Stations (DRS) (2021)

DRS Replaced - 1

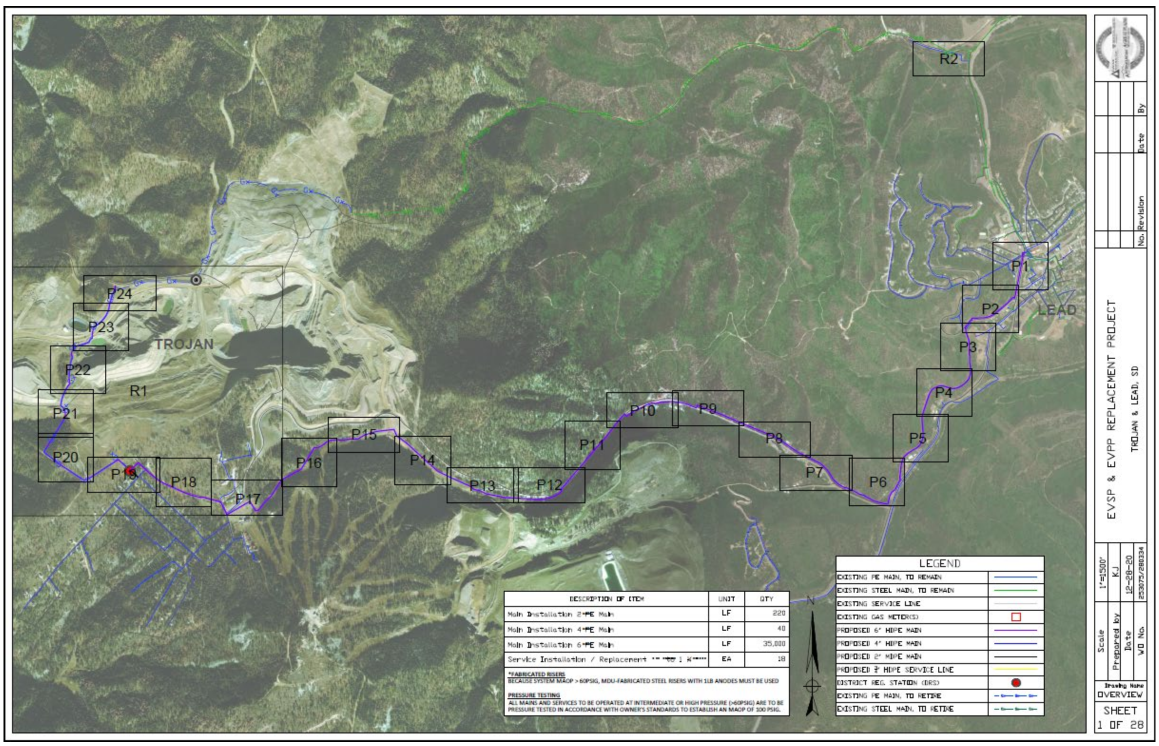


Figure 8 – Trojan/Lead (2021)

Q. Why did the Company undertake the Trojan & Lead Replacement?

A. Trojan & Lead was identified in 2020 & 2021 as Montana-Dakota’s highest risk EVSP and EVPP natural gas distribution system in the state of

South Dakota by the Company's SSIP. The Trojan/Lead project were the first two years of a three-year project scope within the Northern Hills.

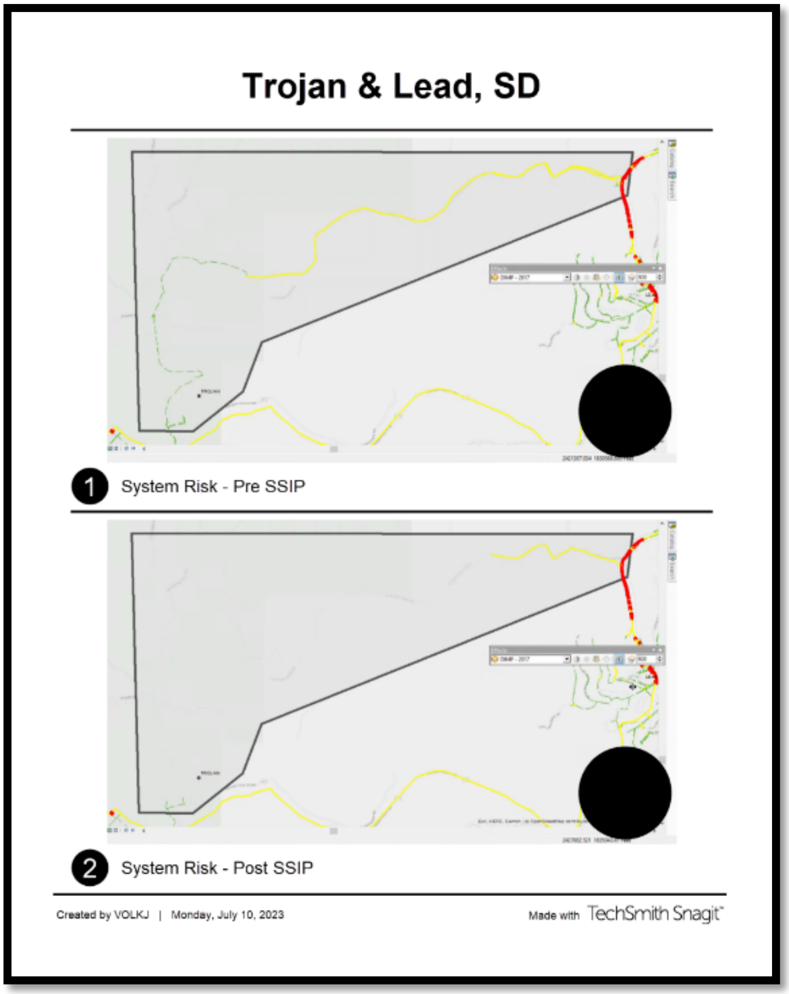


Figure 10 – Trojan/Lead DIMP Risk Comparison '20 (Pre vs Post SSIP)

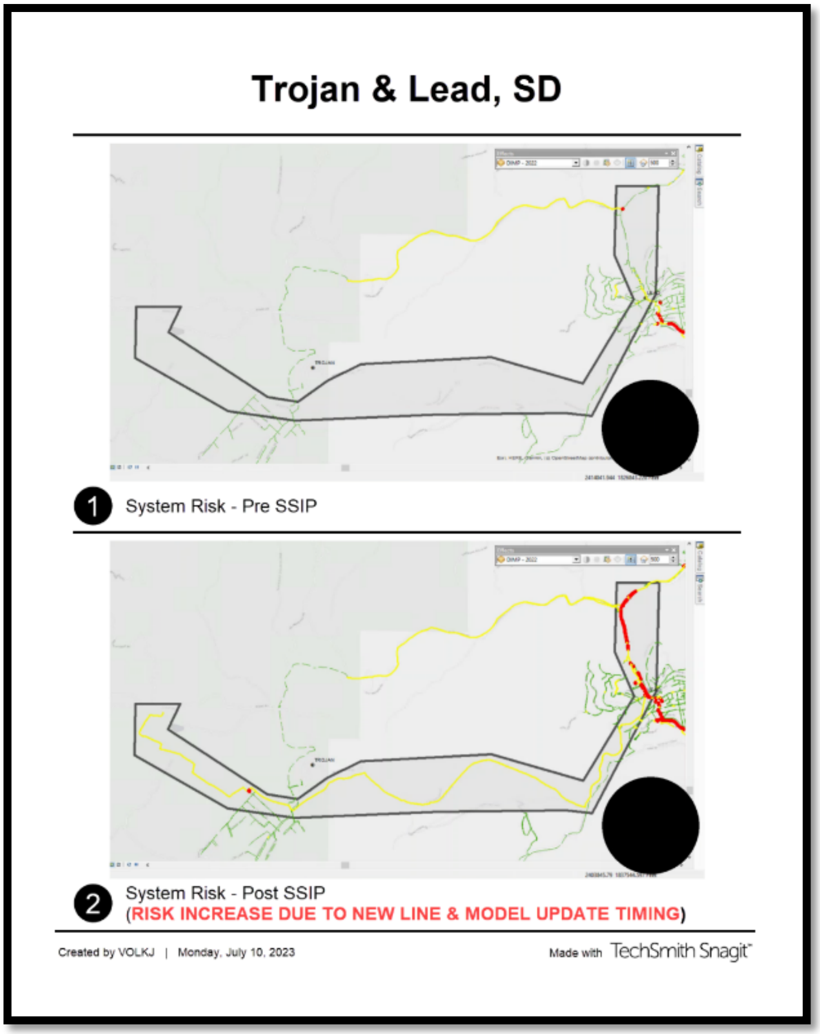


Figure 11 – Trojan/Lead DIMP Risk Comparison '21 (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Trojan/Lead SSIP project was a multi-year project starting in 2020 and completed in 2021.

Q. What are the costs of the project?

A. Project costs are as follows:

Main Replacements - $4,328,540

Service Replacements - $251,514

<u>2022 – Lead/Central City SSIP</u>

Q. Would you please describe the Lead/Central SSIP project?

A. The Lead/Central City SSIP Project replaced EVSP and EVPP natural gas mains and services with MDPE & HDPE lines. Project replacement quantities and type are as follows:

<u>Mains</u>

2" MDPE – 4,285 feet

4" MDPE – 1,480 feet

6" HDPE – 6,075 feet

<u>Services</u>

Service line quantity replaced or re-tested - 54

<u>District Regulator Stations (DRS)</u>

DRS Retired - 4

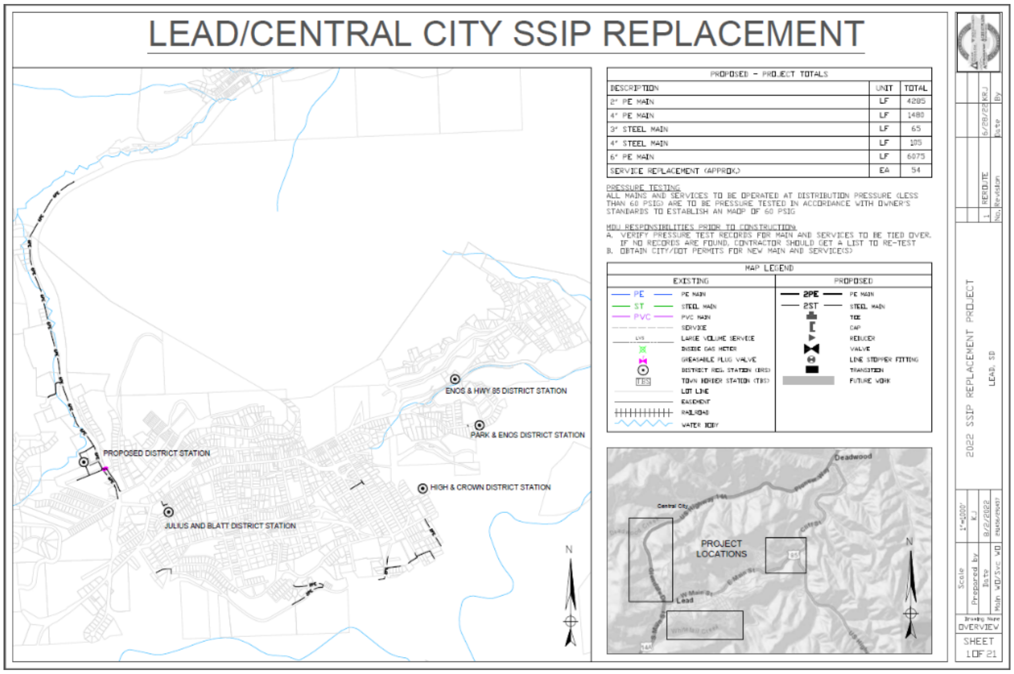


Figure 12 –Lead/Central City (2022)

Q. Why did the Company undertake the Lead/Central City Replacement?

A. Lead/Central City remained in 2022 as Montana-Dakota's highest risk EVSP High Pressure natural gas distribution system in the state of South Dakota by the Company's SSIP. The Lead/Central City project was the third year of a three-year project scope within the Northern Hills.

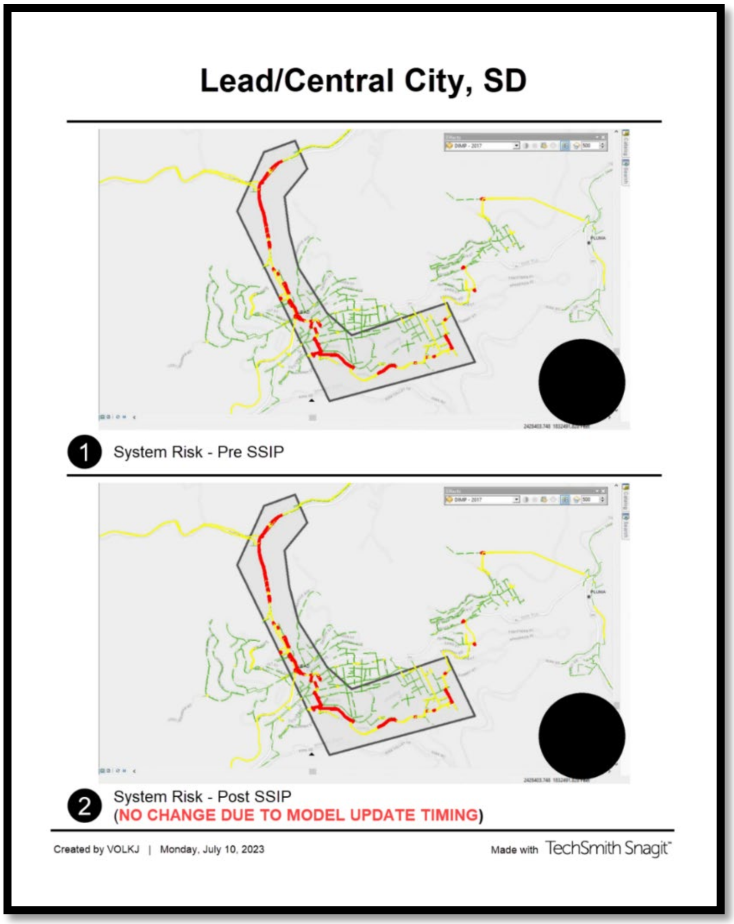


Figure 14 –Lead/Central City DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The Lead/Central City SSIP project was a multi-year project starting in 2020 and completed in 2022.

Q. What are the costs of the project?

A. The costs of the project are as follows:

Main Replacements - $1,275,197

Service Replacements - $423,272

<u>2023 – Rapid City SSIP</u>

Q. Would you please describe the Rapid City SSIP project?

A. The Rapid City SSIP Project replaced EVSP natural gas mains and services with MDPE and HDPE lines. Project replacement quantities and type are as follows:

<u>Mains</u>

2” MDPE – 8,660 feet

4” MDPE – 2,100 feet

6” HDPE – 200 feet

<u>Services</u>

Service line quantity replaced or re-tested - 193

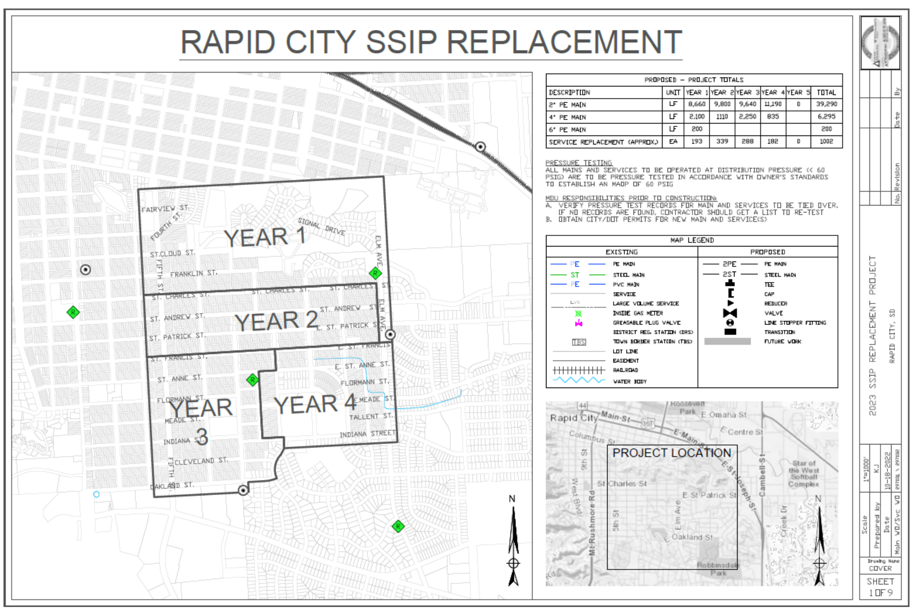


Figure 15 –Rapid City (2023)

Q. Why did the Company undertake the Rapid City Replacement?

A. Rapid City was identified in 2023 as Montana-Dakota's highest risk EVSP and EVPP natural gas distribution system in the state of South Dakota by the Company's SSIP. The Rapid City project is expected to be a four-year project scope.

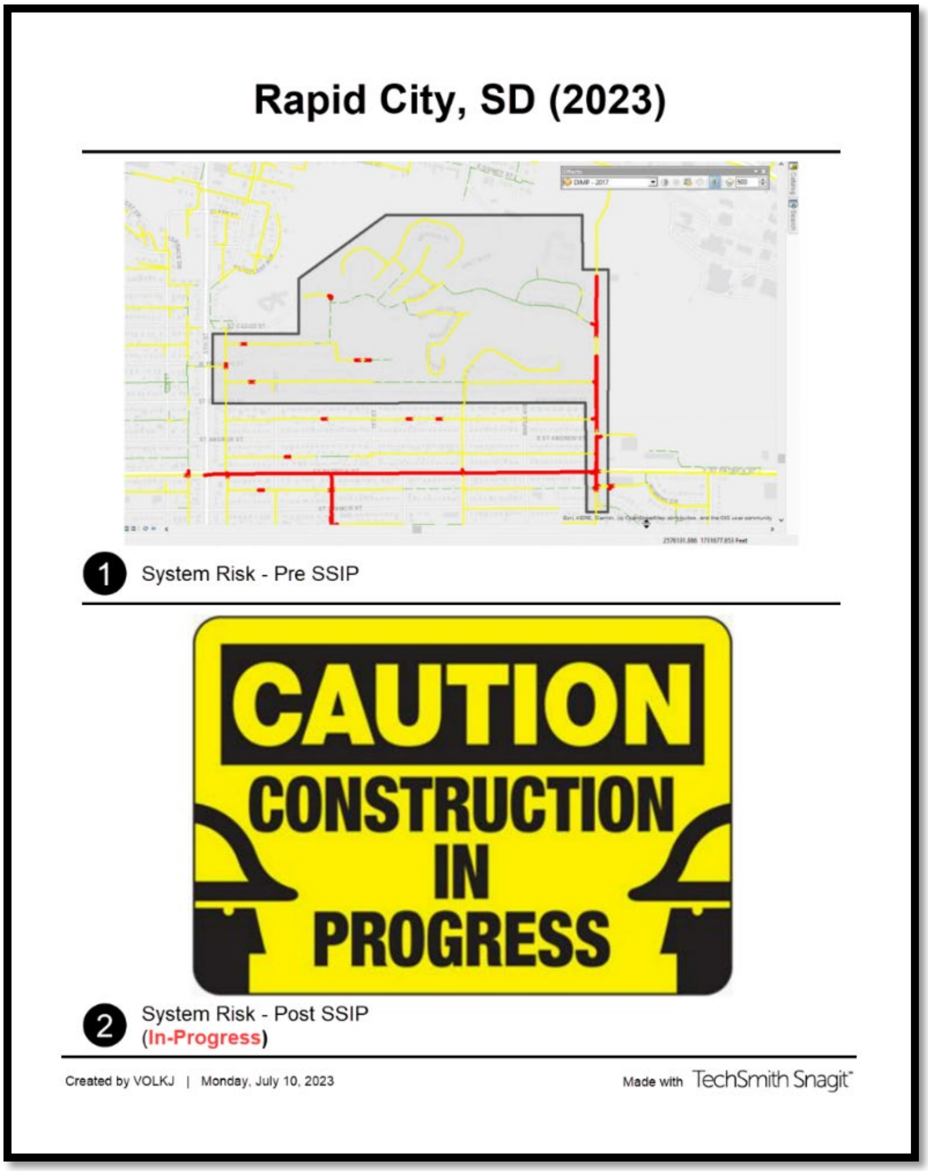


Figure 17 –Rapid City DIMP Risk Comparison (Pre vs Post SSIP)

Q. What is the project timeline?

A. The identified Rapid City SSIP project scope is expected to be a multi-year project starting in 2023 and completing in 2026.

Q. What are the capital cost estimates of the project?

A. The 2023 capital cost is $2,843,575 which includes FP-316059, FP-316064 and FP-323243, as shown on Rule 20:10:13:56, Statement D, Schedule D-2 page 3. The 2024 through 2026 projected capital costs are approximately $2.9 million per year and have not been included in this proceeding.

Q. Does the Company expect SSIP efforts to continue?

A. Pipeline operators have a requirement to implement IMPs that evolve and mature to fit an operator's unique operating environment. The evolution of an operator's IMP program takes time and resources to collect and analyze data to accurately identify the most current high-risk pipelines within any given system. Once a system is prioritized and selected it typically requires multiple years to develop and execute an action plan for full remediation or replacement.

Based on this information, Montana-Dakota expects the SSIP program to continue for the foreseeable future.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No. (LEK-1)

MONTANA-DAKOTA UTILITIES CO.

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. NG23-___

PREPARED DIRECT TESTIMONY OF

LARRY E. KENNEDY

Q1. Please state your name and business address.

A1. My name is Larry E. Kennedy. My business address is 200 Rivercrest Drive SE, Suite 277, Calgary, Alberta, T2C 2X5.

Q2. By whom are you employed?

A2. I am employed by Concentric Advisors, ULC

Q3. What is your position with Concentric Advisors, ULC. ("Concentric")?

A3. I am employed by Concentric as a Senior Vice President.

Q4. On whose behalf are you submitting this Direct Testimony?

A4. I am submitting this Direct Testimony before the South Dakota Public Utilities Commission ("Commission") on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q5. Please describe your education and experience.

A5. I am a Certified Depreciation Professional, with over 40 years of regulatory plant accounting and depreciation experience, and 22 years of depreciation and plant accounting consulting to the regulated utility industry. I have advised numerous energy and utility clients on a wide range of accounting, property tax and utility depreciation matters. Many of these assignments have included the determination of the cost of appropriate annual depreciation accrual rates. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No. (LEK-2), Schedule 1.

Q6. Please describe Concentric's activities in energy and utility engagements.

A6. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q7. Have you testified before any regulatory authorities?

A7. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No. (LEK-2).

I. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q8. What is the purpose of your Direct Testimony?

A8. The purpose of my Direct Testimony is to set forth the results of my full and comprehensive depreciation study of the plant in service of the Montana-Dakota Utilities Co. – Gas Division ("MDU" or the "Company"), as of December 31, 2021. My detailed report, including my analyses and recommendations, is provided in Exhibit No. (LEK-3), titled "Calculated Annual Depreciation Rates Applicable to Gas Plant in Service as of December 31, 2021". My detailed common report, including my analyses and recommendations, is provided in Exhibit No. (LEK-4), titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021". The detailed depreciation study reports were prepared by me or under my direction**.**

Q9. Please provide a brief overview of the analyses that led to your depreciation recommendations.

A9. In preparing the depreciation study report, I analyzed the historic plant account data of MDU to prepare an analysis of the Company's past retirement experience. As a result of COVID protocols, I met (virtually) with the Company's management and operations representatives to determine the extent to which the historic indications would be reflective of the future retirement patterns. Lastly, I also reviewed the average service life and net salvage indications of many North American based gas utilities to test the results of my analysis against the electric industry peers.

Q10. How is the remainder of your Direct Testimony organized?

A10. Section II provides the scope of my study and a summary of my analyses and conclusions. This section also includes a discussion of the major causes of changes in the depreciation accrual rate and amounts as compared to the last study. Section III provides a background on utility depreciation, depreciation methods and procedures. Section IV provides concluding comments.

II. SCOPE OF THE DEPRECIATION STUDY

Q11. Please outline the Scope of the Depreciation Study.

A11. My depreciation study reports set forth the results of the depreciation study for the gas distribution, and general plant assets of the MDU Gas Division, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment, as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the Average Life Group Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU gas assets in service, as of December 31, 2021.

Q12. Please outline the information included in your depreciation study report.

A12. The depreciation study report is presented in nine (9) sections outlined as follows:

Section 1 Study Highlights, presents a summary of the depreciation study and results.

Section 2 Introduction, contains statements with respect to the plan and the basis of the study.

Section 3 Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.

Section 4 Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation.

Section 5 Result of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 2, 3, 4, 5, and 6.

Section 6 Retirement Rate Analysis

Section 7 Net Salvage Calculations

Section 8 Detailed Depreciation Calculations

Section 9 Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis.

Q13. Was the depreciation study prepared using generally accepted standard methods and practices?

A13. Yes. Previous depreciation studies completed for MDU utilized a widely accepted method for the study of the Company's historic data, known as the Retirement Rate Analysis Method. The Retirement Rate Analysis Method is generally accepted as the correct method to use when aged data is available for review. The aged data used in the last study, through December 31, 2015, was available to be incorporated into our database. Additional reliable aged data, for the period January 1, 2016 through to December 31, 2021, was provided by the Company and incorporated in our database. Given the availability of reliable aged data, I prepared the historic study of mortality history using the retirement rate method. A detailed discussion of the retirement rate analysis is presented in Section 9 of my depreciation study report.

Additionally, the service life study included:

- **a review of MDU company practice and outlook, as they relate to plant operation and retirement;**
- **consideration of current practice in the gas system industry, including knowledge of service life estimates used for other gas system companies; and**
- **informed professional judgment which incorporated analyses of all of the above factors.**

My study of the net salvage percentages was based on detailed study prepared under the standard approach, which has commonly become known as the "Traditional method". Within this method, the net salvage transactions (gross salvage proceeds, re-use salvage and costs of removal or retirement) are compared to the original cost of the item being retired. The analysis is prepared on an actual transaction year basis, for as many years as reliable data is available. The analysis then includes a series of 3-year rolling average bands, 5-year rolling average bands, and life to date bands covering all years of transactional data.

As described in later sections of this evidence, the depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation.

The methods described above are generally accepted for use in the development of depreciation rates for regulated utilities.

Q14. Please provide a summary of the results of the depreciation study.

A14. The study results in an annual depreciation expense accrual related to the recovery of original cost (i.e. excluding net salvage requirement) of $22.6 million, when applied to depreciable plant balances, as of December 31, 2021.

The study results are summarized at an aggregate functional group level as follows:

Summary of Original Cost, Accrual Percentages and Amounts

Plant Group	Original Cost	Annual Accrual	
Distribution Plant	$548,934,689	3.21%	$17,637,857
General Plant	$49,954,953	9.87%	$4,931,463
Total Plant in Service	$598,889,642	3.77%	$22,569,320

Q15. How do the above depreciation rates compare to the currently approved depreciation rates?

A15. The following chart summarizes the proposed composite depreciation rates as compared to the currently applied for composite depreciation rates.

Plant Group	Proposed Depreciation Rate	Currently Applied Depreciation Rate
Distribution Plant	3.21%	4.15%
General Plant	9.87%	5.08%
Total Plant in Service	3.77%	4.23%

Q16. Please outline the reasons for the decreased composite depreciation rate for the gas distribution assets.

A16. In the circumstances of the distribution assets, the need for more negative net salvage percentages has had a depreciation rate increase impact that was lesser than the decline caused by the influence of the decreases due to the life extensions in many accounts. The following is a summary of the proposed average service life estimates compared to the currently used estimates, demonstrating the lengthening of the average service lives in three accounts.

Account	Description	Proposed Iowa Curves	Current Iowa Curves
374.2	Rights of Way	65-R3	65-R3
375.0	Distr. Meas & Reg Station Structures	55-R3	60-R3
376.0	Mains	55-R3	40-R3 to 62-R3
378.0	Meas & Reg Station Equip-General	50-R2	50-R2
379.0	Meas & Reg Station Equip-General	45-R2.5	45-R2.5
380.0	Services	50-R2.5	38-R0.5 to 47-R4
381.0	Meter & Meter Installations	31-R3	31-R3
383.0	House Regulators	58-R2.5	60-R3
385.0	Industrial Meas. & Reg. Station Equip	40-R2	40-R4
386.1	Misc. Property on Customer Premises	15-R3	15-R3
387.2	Other Equipment	30-R3	25-R3

The specific reasons for the average service life extensions for each of the large distribution accounts are discussed in Section 3.6 of my report. Additionally, the results of the statistical mortality study are presented for each account, in Section 6 of my report.

Q17. Are the average service life extensions, as noted above, typical for gas distribution assets?

A17. Yes. In a number of recent depreciation studies that I have completed, I have noted that the average service life of gas distribution assets is lengthening throughout North America. While there are a number of factors causing this lengthening of life estimates, the most prevalent reason is the increased focus of utilities in maintaining and life extending the distribution infrastructure. For example, in recent years gas distribution utilities have been pro-active in services structure management and adding enhanced pipeline quality in the type of product used for services.

Likewise, I have noted that the life of distribution assets has also benefited from enhanced technology and the pro-active maintenance programs undertaken by gas distribution utilities. As such, the average service life extensions as observed in this study are consistent with my observations in a number of other gas utilities.

Q23. Please provide a summary of the current and proposed net salvage percentages for distribution plant.

The following is a summary of the proposed net salvage percentages used in the depreciation rate calculations. I note that the current rates differ in many accounts from those proposed in the 2015 depreciation study. It is my understanding that the currently approved depreciation rates related to cost of removal were ultimately negotiated. Therefore, the net salvage percentage comparisons as noted below are based on the percentages as recommended in the 2015 depreciation study.

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
374.2	Rights of Way	0%	-0.02%	0%	0.00% 0.02%
375.0	Distr. Meas & Reg Station Structures	0%	-0.56%	(50)%	1.09% 0.28%
376.0	Mains	(55)%	1.19%	(50)%	1.17% 0.82%

Account	Description	Proposed		Last Depn Study (*)	
		Net Salvage %	Depn Rate	Net Salvage %	Depn Rate
378.0	Meas & Reg Station Equip-General	(30)%	0.60%	(30)%	0.66% 0.74%
379.0	Meas & Reg Station Equip-General	(5)%	0.07%	(15)%	0.37% 0.37%
380.0	Services	(100)%	1.18%	(200)%	4.83% 4.97%
381.0	Meter & Meter Installations	(20)%	1.74%	(20)%	0.96% 2.14%
383.0	House Regulators	(5)%	0.13%	0%	0.00% 0%
385.0	Industrial Meas. & Reg. Station Equip	(10)%	0.21%	(15)%	0.66% 0.94%
386.1	Misc. Property on Customer Premises	0%	0%	0%	0.00%
387.2	Other Equipment	0%	0%	0%	0.01% 0.00%

(*)Rates identified in yellow represent the depreciation rate after negotiated settlement.

As noted above, the depreciation rates related to cost of removal and salvage currently used were changed significantly from the depreciation rates as proposed in the 2015 depreciation study. The current study has noted the continued trend to increased levels of recovery for cost of removal.

The detailed analysis of the net salvage estimates is provided in Section 7 of my MDU report.

Q18. Is the trend for more negative net salvage percentage, as noted above, typical for gas distribution assets?

A18. Yes. The increased amount of cost of removal expenditures is a common trend throughout North American utilities. In fact, this trend has been the most significant change noted in depreciation studies over the past five years. Accordingly, it has become the most debated topic of depreciation studies filed throughout North America, as well as being a significant topic of discussion at depreciation conferences. At the 2018 Society of Depreciation Professionals conference held in September, there were four presentations regarding the large increase in cost of removal expenditures. This trend has been witnessed over virtually all electric, gas and pipeline utilities. As such, the trend witnessed in my MDU study is consistent with depreciation studies conducted across North America.

Q19. What is causing this trend to increased cost of removal of utility assets?

A19. It is generally accepted that there exist three main causes of increases.

Firstly, as the average age of utility assets continue to be extended, the impact of inflation becomes more pronounced. As the average service life has increased, the length of time between the original installation of the assets in some accounts and the estimated average time of retirement of the assets is getting longer. The net salvage percentage is calculated by dividing the costs to remove the asset in dollars of the time when the asset is removed by the original cost dollar of the time of installation. Given that the major component of cost of removal is labor, this increase in the life expectation, also results in an increased length of time that the labor associated with the removal is longer. To the extent that the average service lives for distribution assets have extended, the impact as described applies to a number of the MDU gas distribution accounts.

Secondly, the costs associated with the removal (or retirement) of utility assets must deal with increased environmental and regulatory requirements. For example, the costs related to the safe removal of existing infrastructure have greatly increased since the assets were originally installed. Additionally, the utilities are required to deal with the increased level of regulations within areas that are much more densely populated at the time of removal of the assets as compared to when the assets were originally placed into service. As distribution assets are often removed in municipal areas, the need to effectively deal with urban growth and density within the areas adds a significant cost to the removal of the assets that did not exist at the time of the original installation of the assets. When the assets were originally installed, the distribution assets were largely within greenfield developments, whereas now, when the assets are removed, the utility must deal with (for example) applications for road closures and re-routing, noise bylaws, and performing work within and around developed and landscaped yards.

Lastly, as utilities have implemented new and enhanced accounting systems, the ability to better track capital projects has improved the processes to track capital project costs more accurately. This provides the ability for direct charging labor associated to costs of removal specifically to cost of removal. Likewise, in circumstances where the utility uses an allocation of the total project costs to recognize that a portion of the capital project relates to the removal of assets, the advancements in the work order and plant accounting systems provide better information to allow the utility to better develop proper allocation factors.

Q20. Was a Common depreciation study also completed?

A20. Yes, a depreciation study was also conducted on the MDU Common assets. My detailed report, including my analyses and recommendations, is provided in Exhibit No. (LEK-4), titled "Calculated Annual Depreciation Rates Applicable to Common Plant in Service as of December 31, 2021".

Q21. Please provide a summary of the results of the Common depreciation study.

A21. The study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $4.3 million, when applied to depreciable plant balances, as of December 31, 2021. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
General Plant	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970
TOTAL	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970

III. DEPRECIATION METHODS AND PROCEDURES

Q22. How is depreciation defined for a rate regulated utility?

A22. Depreciation defined – "Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities".[1] When considering the action of the elements, my average service life recommendations have considered large catastrophic events that have occurred and impacted the life estimates of utility assets across North America through our use of peer analysis. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, actions of third parties and other natural forces of nature, and these forces of retirement should be included in the determination of the average service life.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric system utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line Method of depreciation, which was adopted for use in my study.

Q23. Please outline the depreciation methods and procedures used in your depreciation study.

1 Federal Energy Regulatory Commission, Part 201Defination 12.B (2020)

A23. The calculation of annual and accrued depreciation, based on the Straight-Line Method, requires the estimation of survivor curves and the selection of group depreciation procedures, as discussed below.

Depreciation Grouping Procedures - When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. In the determination of the depreciation rates in this study, the use of the Average Service Life Procedure has been continued.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and Average Life Group Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations. Amortization accounting has been continued in this study in a manner largely consistent with the prior study. The following is a summary of the proposed amortization periods compared to the currently used estimates, demonstrating the lengthening of the average service lives in two accounts.

Account	**Description**	**Proposed Amortization Period in Years**	**Current Amortization Period in Years***
391.1	Office Furniture & Equipment	15	15
391.3	Computer Equipment - PC	5	5
393.0	Stores Equipment	30	30
394.1	Tools, Shop, & Garage Equipment	20	18
394.3	Vehicle Maintenance Equipment	20	20
395.0	Laboratory Equipment	20	20

Account	Description	Proposed Amortization Period in Years	Current Amortization Period in Years*
397.1	Communication Equipment – Fixed Radios	15	15
397.2	Communication Equipment – Mobile Radios	15	15
397.3	General Telephone Communication Equipment	10	10
397.8	Network Equipment	5	5
398.0	Miscellaneous Equipment	25	20

***Year equivalent calculated based on rate after negotiated settlement.**

A detailed account by account analysis of the factors considered in the selection of my recommended average service life estimates is provided in Section 3.6 of my depreciation study report.

Q24. Please outline any changes that you made in the depreciation method, grouping procedures or remaining life calculations as compared to previous depreciation studies.

A24. The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the Straight-Line Method, the Average Life Group Procedure was applied on a remaining life basis. However, I note that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintage approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a Calculated Accumulated Depreciation ("CAD") weighted calculation in the textbook Depreciation Systems, by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994, under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies was based on a broad averaging of the composite remaining life. This method is also discussed as the Amortization Method in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

In the manner in which I developed the remaining life calculations, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. Specifically, my calculations are made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole as compared to applying one overall composite life to all vintages as done in prior studies. My calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account. Consistent with the plant accounting systems of most utilities, MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. As such, the accumulated depreciation by account is allocated within the account to each

vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates and the achieved age of each vintage.

2. The estimated remaining life of each vintage within each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving, as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on a CAD approach to the remaining life calculations is widely considered to be the most accurate. I agree and view this methodology as the correct and most appropriate calculation.

IV. CONCLUDING REMARKS

Q25. What is your conclusion with respect to Montana-Dakota's proposed Depreciation expense?

A25. My conclusion is that Montana-Dakota's requested depreciation rates, resulting in a composite depreciation rate of 3.77% for the Gas Division and 5.31% for the Common Plant, reasonably reflects the annual consumption of the undepreciated service value of the utility plant in service. Therefore, the use of the depreciation rates as presented in my report, by account, will provide for an appropriate amount of depreciation expense in the Company's revenue requirement. Therefore, I recommend that the proposed depreciation rates set forth in the depreciation studies, that I prepared for this proceeding, be adopted by the Commission for regulatory purposes as well as by the Company for financial reporting purposes.

Q26. Does this conclude your Direct Testimony?

A26. Yes, it does.

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals (“SDP”) and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and

Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).
- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)
- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently

have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.
- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.
- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.
- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for

submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.

- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public

Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.
- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.
- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.
- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional

full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	United Illuminating Company	United Illuminating Company	Connecticut Public Utilities Regulatory Authority	22-08-08
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	Case No. PU-22-194
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	RP22-1033-0000
2023	Indiana American Water Company	Indiana American Water Company	Indiana Utility Regulatory Commission	Cause No. 45870
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	Public Service Commission of the State of Montana	2022.11.099

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	Enbridge Gas Inc.	Enbridge Gas Inc.	Ontario Energy Board	EB-2022-0200
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243
2022	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	Manitoba Hydro 2023/24 & 2024/25 General Rate Application
2023	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	Application No. PNG NE2023 to 2024 RRA

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO GAS PLANT IN SERVICE
as of December 31, 2021

Prepared for Montana-Dakota Utilities Co.
April 2023

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
587.997.6489

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to Montana-Dakota Utilities Co.'s ("MDU" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the natural gas distribution and general plant accounts, as of December 31, 2021. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of utility plant, as of December 31, 2021.

The depreciation rates are based on the broad group Straight-Line method using the Average Life Group ("ALG") procedure and were applied on a Remaining Life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2021, are amortized over the composite remaining life of assets.

MDU's accounting policy has not changed since the last depreciation study.

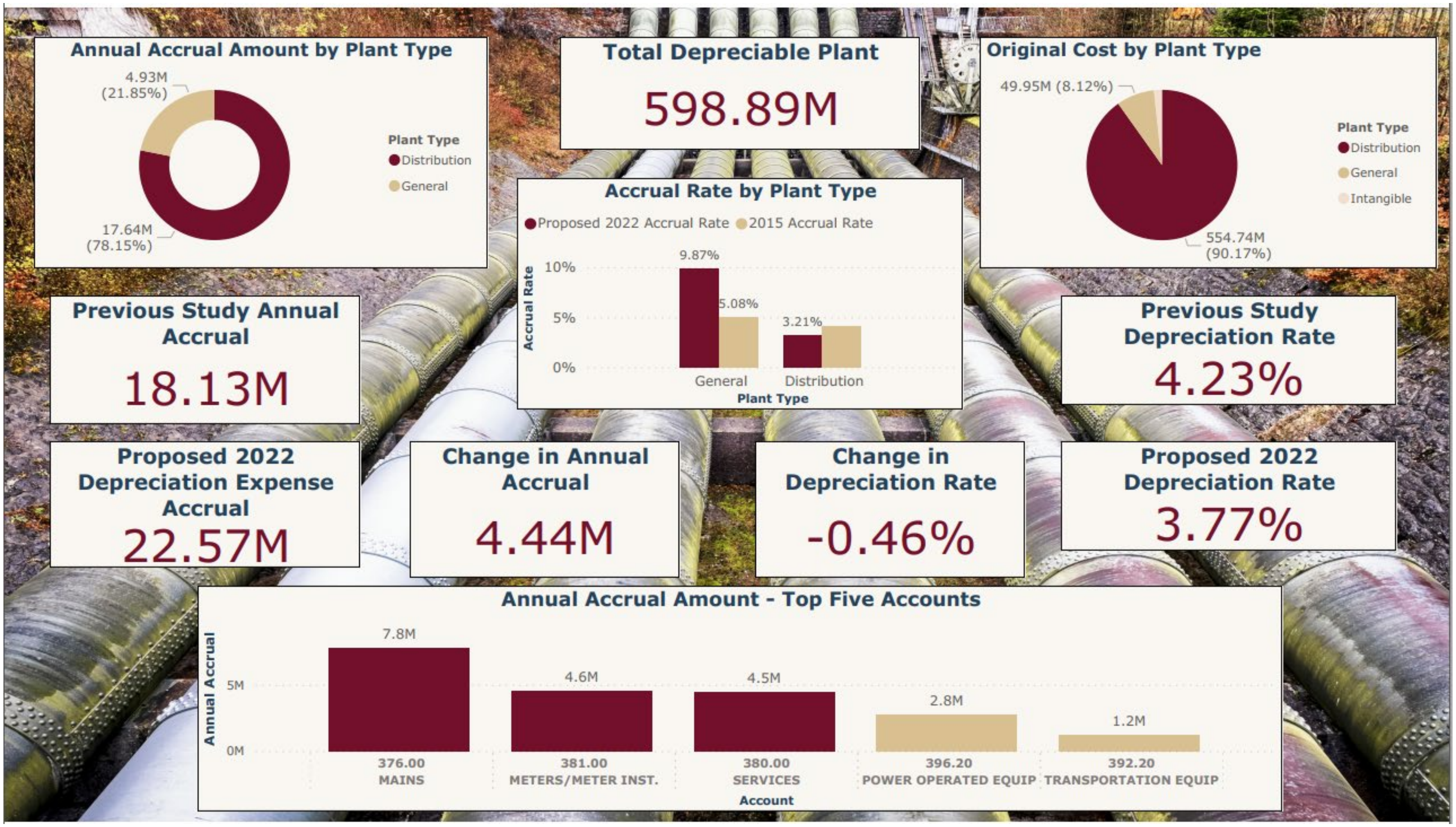
Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service, as of December 31, 2021. The annual depreciation accrual rates are summarized by tables related to:

- the total required annual accrual amounts;
- the annual accrual requirements related to the recovery of the original cost of the investment; and
- the annual accrual amount related to the recovery of the expected net salvage requirements at the time of retirement.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $22.6 million, when applied to depreciable plant study balances, as of December 31, 2021, of $598 million. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
Distribution Plant	$548,934,689	4.15%	$16,423,189	3.21%	$17,637,857
General Plant	$49,954,953	5.08%	$1,709,320	9.87%	$4,931,463
TOTAL	**$598,889,642**	**4.23%**	**$18,132,509**	**3.77%**	**$22,569,320**


Annual Accrual Amount by Plant Type
4.93M (21.85%)
17.64M (78.15%)
Plant Type
Distribution
General
Total Depreciable Plant
598.89M
Original Cost by Plant Type
49.95M (8.12%)
554.74M (90.17%)
Plant Type
Distribution
General
Intangible
Accrual Rate by Plant Type
Proposed 2022 Accrual Rate
2015 Accrual Rate
Accrual Rate
10%
5%
0%
9.87%
5.08%
3.21%
General
Distribution
Plant Type
Previous Study Annual Accrual
18.13M
Previous Study Depreciation Rate
4.23%
Proposed 2022 Depreciation Expense Accrual
22.57M
Change in Annual Accrual
4.44M
Change in Depreciation Rate
-0.46%
Proposed 2022 Depreciation Rate
3.77%
Annual Accrual Amount - Top Five Accounts
Annual Accrual
5M
0M
7.8M
4.6M
4.5M
2.8M
1.2M
376.00 MAINS
381.00 METERS/METER INST.
380.00 SERVICES
396.20 POWER OPERATED EQUIP
392.20 TRANSPORTATION EQUIP
Account

SECTION 2

2 BASIS OF THE STUDY

2.1 Scope

This study sets forth the results of the depreciation study for the natural gas distribution and general plant assets of MDU, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the ALG Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU assets in service, as of December 31, 2021.

The service life estimates resulting from the study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data recorded through December 31, 2021;
- a review of MDU company practice and outlook, as they relate to plant operation and retirement; and
- consideration of current practice in the gas system industry, including knowledge of service life estimates used for other gas system companies.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The estimated survivor curves used in this study are based on studies incorporating actual data through 2021 for most accounts.

2.2 Plan of Study

This study is presented in the following order:

Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the basis of the study
Section 3:	Development of the Required Depreciation Rates, presents descriptions of the methods used and factors considered in the service life study
Section 4:	Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation
Section 5:	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, and 1B.
Section 6:	Presents the results of the Retirement Rate Analysis
Section 7:	Presents the results of the Net Salvage Study
Section 8:	Presents the results of the Detailed Depreciation Calculations
Section 9:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10:	Estimation of Net Salvage discusses the methodology used in calculating net salvages

2.3 Depreciation

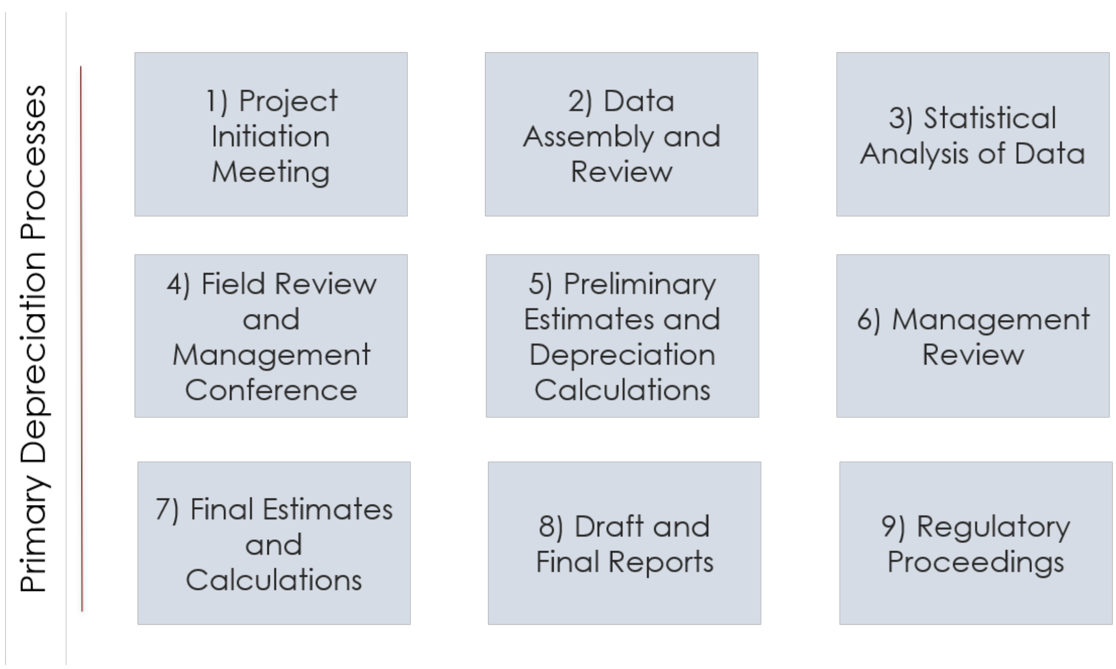
A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. selection of an appropriate grouping procedure;
4. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
5. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

Consistent with the current MDU practice, amortization accounting continues to be recommended for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.



2.4 Information Provided by MDU

MDU has provided Concentric with the required information, as of December 31, 2021 for all accounts being studied in this study. This information includes the following:

- Current balances by vintage year for each account (aged balances) through December 31, 2021. The balances provide the amount of investment sorted by installation year. This file is only inclusive of plant in service and does not include any retirement information;
- retirement transactions for all accounts through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired; and
- cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.5 Data Reconciliation

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;
- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that any adjusting transactions are properly accounted for within the databases.

SECTION 3

3 DEVELOPMENT OF THE REQUIRED DEPRECIATION RATES

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e. Iowa curve) and net salvage recommendations (i.e. the depreciation parameters). Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for MDU have been calculated in accordance with the Straight-Line method, the ALG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature.

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Gas Utilities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service - that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.1.1 Study Depreciation Methods and Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group (ALG) and Equal Life Group (ELG) procedures.

In the ALG Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

While the Equal Life Group Procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Straight-Line Method, Average Life Group Procedure is a commonly used depreciation calculation that has been widely accepted in jurisdictions throughout North America including MDU in prior studies. Concentric recommends its continued use.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and ALG Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to correct the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.1.2 Changes Since Last MDU Full Depreciation Study

The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the straight-line method, the ALG Procedure applied on a remaining life basis. However, Concentric notes that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintaged remaining life approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a CAD weighted calculation in the textbook Depreciation Systems by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994 under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies was based on a broad averaging of the composite remaining life. The method is also discussed as the Amortization Method (AM) in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

When depreciation rates are calculated utilizing a remaining life technique, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. This calculation is made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole. This calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account.

   MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. Concentric notes that this is the practice employed by virtually all regulated utilities. As such, the accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates and the achieved age of each vintage.

2. The estimated remaining life of each vintage with each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on CAD approach to the remaining life calculations is widely considered to be the most accurate. Concentric agrees and views this methodology as the correct and most appropriate calculation.

3.1.3 Energy Transition

Long life assets such as those comprising MDU's system can be restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also, and to a much greater extent, by economic forces of retirement. Specifically, the changing North American marketplace for natural gas demand and the rapidly emerging trend of decarbonization legislation may have a significant impact on the estimated service lives of the MDU system.

There are several factors affecting the economic viability of the MDU system. Long life assets, such as natural gas distribution systems, are subject to a number of different forces of economic retirement, including changes in legislation constricting the use of carbon-based fuels.

While there is strong evidence that the future of natural gas may be impacted by climate change legislation, it is still unknown to what extent this change will impact MDU's system. The introduction of hydrogen, for example, may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel. The same may be true of renewable natural gas or other low carbon fuels. However, it may also be true that the move from carbon-based fuels necessitates a greater electrification of the grid, in which case there may be a life shortening impact on the MDU system.

The future growth and retirement programs of the MDU gas system may be significantly different than the retirement patterns witnessed in the past. While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. Consistent with the reduction in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050.

Common depreciation practice is to deal with the anticipated large-scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations. However, at this time the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide the indications of the changes in the utilization levels. Concentric views that additional study of the changes is required before the introduction of a Life Span date, for the MDU gas system, into the depreciation rate calculations. This will cause a significant increase in the depreciation rate. However, Concentric notes that future depreciation studies of the MDU gas system may require the introduction of an economic planning horizon into the depreciation rate calculations.

3.1.4 Survivor Curves

The use of an average service life or a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

---

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

3.1.5 Survivor Curve and Net Salvage Judgments

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from Concentric's studies of other gas utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based mostly in part on historical data related to actual retirement activity for the years 1995 through 2021, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Concentric notes the data from the previous depreciation consultant was used and considered in the historic net salvage analysis, but more relevancy was placed on the more recent data from 2009 through 2021 provided directly to Concentric by MDU. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 376 – DISTRIBUTION – MAINS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$278,503,430	46.50%	47-R4	55-R3	-50%	-55%

The investment in Distribution Mains is approximately $278 million, representing 47 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1916 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $11,076,857.16 were recorded for this period. The currently approved life parameter is an Iowa 47-R4 that produced a fit with a related residual measure of 4.918. An Iowa 55-R3 produced a better fit with a residual measure of 4.0696, as depicted on page 6-10. Discussions with MDU operational and management staff indicated that the Iowa 55-R3 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 55-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 55-R3 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of negative 50 percent. This account has shown a wide range in historical net salvage activity since 1995. The range has been from negative eight percent to negative 69 percent. A three-year band produces results that range from negative eight percent to over negative 100 percent. The five-year band ranges from negative eight percent to over negative 100 percent. The full depth band averages negative 69 percent. At this time, Concentric recommends that a slight increase to a negative 55 percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 379 – MEAS. & REG STATION EQUIP – CITY GATE

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$11,726,166	1.96%	45-R2.5	45-R2.5	-15%	-5%

The investment in this account relates to Measuring and Regulating Station Equipment – City Gate. The investment in this account is approximately $11.7 million, representing 2 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1951 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $193,535.46 were recorded for this period. The currently approved and recommended life parameter is an Iowa 45-R2.5 that produced a fit with a related residual measure of 3.22, as depicted on page 6-20. Discussions with MDU operational and management staff indicated that the Iowa 45-R2.5 will continue to be a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 45-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends the Iowa 45-R2.5 to continue to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of negative 15 percent. This account has shown a wide range in historical net salvage activity since 1995. The range has been from negative three percent to positive 15 percent. A three-year band produces results that range from negative 56 percent to positive 20 percent. The five-year band ranges from negative eight to positive 14 percent. The full depth band averages negative two percent. At this time, Concentric recommends that a slight step down to a negative five percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 380 – DISTRIBUTION – SERVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$148,582,913	24.81%	47-R4	50-R2.5	-200%	-100%

The investment in Distribution Services is approximately $149 million, representing 25 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1901 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $6,905,599.88 were recorded for this period. The currently approved life parameter is an Iowa 47-R4 that produced a fit with a related residual measure of 4.1875. An Iowa 50-R2.5 produced a better fit with a residual measure of 3.6545, as depicted on page 6-24. Discussions with MDU operational and management staff indicated that the Iowa 50-R2.5 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 50-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 50-R2.5 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of negative 200 percent. This account has shown a wide range in historical net salvage activity since 1995. The range has been from negative 117 percent to negative 194 percent. A three-year band produces results that range from negative 117 percent to over negative 200 percent. The five-year band ranges from negative 117 percent to over negative 200 percent. The full depth band averages negative 167 percent. At this time, Concentric recommends that a step down to a negative 100 percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 381 – METERS & METER INSTALLATIONS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$84,646,197	14.13%	31-R3	31-R3	-20%	-20%

The investment in this account is approximately $85 million, representing 14 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1921 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $15,071,767.65 were recorded for this period. The currently approved and recommended life parameter is an Iowa 31-R3 that produced a fit with a related residual measure of 0.4746, as depicted on page 6-29. Discussions with MDU operational and management staff indicated that the Iowa 31-R3 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 31-R3 continues to be a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 31-R3 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of negative 20 percent. This account has shown a wide range in historical net salvage activity since 1995. The range has been from negative 20 percent to positive three percent. A three-year band produces results that range from negative 27 percent to positive 39 percent. The five-year band ranges from negative 25 percent to positive four percent. The full depth band averages positive 17 percent. At this time, Concentric recommends the continued use of a negative 20 percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 383 – DISTRIBUTION – HOUSE REGULATORS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$12,799,915	2.14%	60-R3	58-R2.5	0%	-5%

The investment in this account relates to Distribution – House Regulators. The investment in this account is approximately $13 million, representing 2 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1952 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $906,585 were recorded for this period. The currently approved life parameter is an Iowa 60-R3 that produced a fit with a related residual measure of 2.3347. An Iowa 58-R2.5 produced a fit with a residual measure of 2.3719, as depicted on page 6-33. Discussions with MDU operational and management staff indicated that the Iowa 58-R2.5 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 58-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 58-R2.5 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of zero percent. This account has shown a small range in historical net salvage activity since 1995. The range has been from negative two percent to positive 46 percent. A three-year band produces results that range from negative 29 percent to over positive 200 percent. The five-year band ranges from negative 25 percent to over positive 200 percent. The full depth band averages negative two percent. At this time, Concentric recommends that a change to a negative five percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 390 – STRUCTURES AND IMPROVEMENTS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$15,766,936	2.63%	40-R2	45-R2	-10%	0%

The investment in this account is approximately $16 million, representing 2.6 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1928 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $1,720,951.70 were recorded for this period. The currently approved life parameter is an Iowa 40-R2 which produced a fit with a related residual measure of 2.6961. An Iowa 45-R2 produced a fit with a related residual measure of 2.296, as depicted on page 6-47. Discussions with MDU operational and management staff indicated that the Iowa 45-R2 is a good representation of the historical life and future expectations. Based on the above and considerations, and on Concentric's experience, an Iowa 45-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 45-R2 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of negative 10 percent. This account has shown a small range in historical net salvage activity since 1995. The range has been from positive 68 percent to positive 140 percent. A three-year band produces results that range from negative 17 percent to over positive 300 percent. The five-year band ranges from negative 16 percent to over positive 200 percent. The full depth band averages positive 68 percent. At this time, Concentric recommends that a change to a zero percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 392.2 – TRANSPORTATION EQUIPMENT – VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$12,856,198	2.15%	9-R3	10-L2	20%	20%

The investment in Transportation Equipment - Vehicles is approximately $13 million, representing 2.15 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1953 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $4,086,583.85 were recorded for this period. The currently approved life parameter for the MDU account is an Iowa 9-R3 that produced a fit with a related residual measure of 0.566. Data analysis and discussion with MDU personnel indicated that a slight adjustment to a 10-L2, with a residual measure of 0.2731, produced a better visual and mathematical fit, and is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L2 going forward to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 20 percent. This account has shown a close range in historical net salvage activity since 1995. The range has been from positive 11 percent to positive 23 percent. A three-year band produces results that range from positive 17 percent to positive 32 percent. The five-year band ranges from positive 17 percent to positive 31 percent. The full depth band averages positive 23 percent. At this time, Concentric recommends that a positive 20 percent net salvage estimate continue to be used in the depreciation calculations within this study.

ACCOUNT 396.2 – POWER OPERATED EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$9,040,554	1.51%	3-L1	3-L1	85%	85%

The investment in this account relates to Power Operated Equipment.

The investment in Power Operated Equipment is approximately $9 million, representing 1.51 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1953 through 2021, were analyzed by the retirement rate method. Retirements, for the period 1995 through 2021, of $55,635,279.87 were recorded for this period. The currently approved and recommended life parameter for the MDU account is an Iowa 3-L1 that produced a fit with a related residual measure of 0.6294. This is still a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 3-L1 going forward to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 85 percent. This account has shown a close range in historical net salvage activity since 2009. The range has been from positive 81 percent to positive 102 percent. A three-year band produces results that range from positive 70 percent to positive 111 percent. The five-year band ranges from positive 75 percent to positive 104 percent. The full depth band averages positive 87 percent. At this time, Concentric recommends the continued use of a positive 85 percent net salvage estimate be used in the depreciation calculations within this study.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account	Title	Investment	Recommended Amortization Period in Years
391.1	Office Furniture & Equipment	$307,608	15
391.3	Computer Equipment – PC	$18,699	5
393.0	Stores Equipment	$103,298	30
394.1	Tools, Shop, & Garage Equipment	$7,859,822	20
394.3	Vehicle Maintenance Equipment	$36,373	20
395	Laboratory Equipment	$316,786	20
397.1	Communication Equipment – Fixed Radios	$1,190,544	15
397.2	Communication Equipment – Mobile Radios	$461,355	15
397.3	General Telephone Communication Equipment	$128,459	10
397.8	Network Equipment	$40,306	5
398.0	Miscellaneous Equipment	$71,705	25

For the purpose of calculating annual amortization amounts, as of December 31, 2021, the book depreciation reserve for each plant account (or sub-account) is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

4.2 Monitoring of Book Accumulated Depreciation

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual vintage remaining lives.

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study and are shown in Tables 1, 1A, and 1B, related to investment as of December 31, 2021. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the ALG procedure, based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The following tables provide summaries by account of the original cost of investment, calculated and booked accumulated depreciation amounts, the required amount of annual depreciation expense, the required depreciation rate to be applied against the original cost of the account and the estimated composite remaining life of the surviving plant in service.

The detailed calculations of annual depreciation applicable to depreciable assets, as of December 31, 2021, are presented in account sequence starting in Section 5 – Page 5-2. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth (for each installation year) the original cost, calculated accrued depreciation and the calculated annual accrual.

MONTANA-DAKOTA UTILITIES CO. - GAS PLANT

TABLE 1. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT AS OF DECEMBER 31, 2021

- TOTAL -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ANNUAL AMOUNT	RATE	REMAINING LIFE
DISTRIBUTION PLANT									
374.2	RIGHTS OF WAY	65-R3	0	1,286,382	162,420	208,959	18,723	1.46%	56.8
375.0	DISTR. MEAS & REG STATION STRUCTURES	55-R3	0	1,707,340	472,570	673,425	21,947	1.29%	39.8
376.0	MAINS	55-R3	-55	278,503,430	106,782,375	107,127,614	7,797,758	2.80%	41.4
378.0	MEAS & REG STATION EQUIP-GENERAL	50-R2	-30	5,144,890	1,577,772	1,784,120	120,684	2.35%	38.2
379.0	MEAS & REG STATION EQUIP-CITY GATE	45-R2.5	-5	11,726,166	2,022,513	2,545,424	250,406	2.14%	37.6
380.0	SERVICES	50-R2.5	-100	148,582,913	64,977,739	102,882,033	4,501,152	3.03%	39.1
381.0	METERS & METER INSTALLATIONS	31-R3	-20	84,646,197	39,354,497	30,642,661	4,596,439	5.43%	19.0
383.0	HOUSE REGULATORS	58-R2.5	-5	12,799,915	3,259,696	3,576,574	218,114	1.70%	43.9
385.0	INDUSTRIAL MEAS. & REG. STATION EQUIPMENT	40-R2	-10	2,750,416	689,019	784,042	68,220	2.48%	30.9
386.1	MISC. PROPERTY ON CUSTOMER'S PREMISES	15-R3	0	1,680	1,680	1,680	-	0.00%	-
387.2	OTHER EQUIPMENT	30-R3	0	1,785,360	493,740	562,854	44,414	2.49%	21.7
TOTAL DISTRIBUTION PLANT				**548,934,689**	**219,794,021**	**250,789,386**	**17,637,857**	**3.21%**	
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	45-R2	0	15,766,936	4,479,705	6,201,672	277,543	1.76%	32.2
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	307,608	184,956	127,853	60,397	19.63%	6.0
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	18,699	2,488	2,828	3,620	19.36%	4.3
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	20-R1	10	450,168	189,548	371,635	2,224	0.49%	10.6
392.2	TRANSPORTATION EQUIPMENT	10-L2	20	12,856,198	3,940,863	2,982,809	1,245,756	9.69%	6.2
393.0	STORES EQUIPMENT	30-SQ	0	103,298	39,829	32,134	4,184	4.05%	18.4
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	7,859,822	2,022,141	2,229,659	363,050	4.62%	14.9
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	36,373	26,667	26,707	1,811	4.98%	5.3
395.0	LABORATORY EQUIPMENT	20-SQ	0	316,786	116,700	59,620	43,180	13.63%	12.6
396.1	POWER OPERATED EQUIPMENT - TRAILERS	25-L2	30	1,306,142	242,246	555,146	16,911	1.29%	18.4
396.2	POWER OPERATED EQUIPMENT	3-L1	85	9,040,554	687,840	(2,072,744)	2,755,719	30.48%	1.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	1,190,544	661,093	620,243	89,145	7.49%	6.7
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	461,355	331,382	318,207	36,061	7.82%	4.2
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	128,459	60,170	43,271	16,317	12.70%	5.3
397.8	NETWORK EQUIPMENT	5-SQ	0	40,306	13,469	10,267	9,534	23.65%	3.3
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	71,705	26,324	(26,865)	6,011	8.38%	15.8
TOTAL GENERAL PLANT				**49,954,953**	**13,025,422**	**11,482,441**	**4,931,463**	**9.87%**	
TOTAL GAS PLANT STUDIED				**598,889,642**	**232,819,442**	**262,271,827**	**22,569,320**	**3.77%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			10,496,877					
374.1	LAND			1,202,798					
386.2	CNG REFUELING STATION			-					
387.1	CATHODIC PROTECTION EQUIPMENT			-					
389.0	LAND & LAND RIGHTS GENERAL			2,603,081					
TOTAL PLANT				613,192,398					

MONTANA-DAKOTA UTILITIES CO. - GAS PLANT

TABLE 1A. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT AS OF DECEMBER 31, 2021
- LIFE -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ANNUAL ACCRUAL AMOUNT	RATE	REMAINING LIFE
DISTRIBUTION PLANT									
374.2	RIGHTS OF WAY	65-R3	0	1,286,382	162,420	195,205	19,037	1.48%	56.8
375.0	DISTR. MEAS & REG STATION STRUCTURES	55-R3	0	1,707,340	472,570	466,229	31,494	1.84%	39.8
376.0	MAINS	55-R3	0	278,503,430	68,891,855	80,337,693	4,487,628	1.61%	41.4
378.0	MEAS & REG STATION EQUIP-GENERAL	50-R2	0	5,144,890	1,213,671	1,440,095	89,583	1.74%	38.2
379.0	MEAS & REG STATION EQUIP-CITY GATE	45-R2.5	0	11,726,166	1,926,203	2,329,465	241,658	2.06%	37.6
380.0	SERVICES	50-R2.5	0	148,582,913	32,488,870	37,379,806	2,742,792	1.85%	39.1
381.0	METERS & METER INSTALLATIONS	31-R3	0	84,646,197	32,795,414	30,156,432	3,127,783	3.70%	19.0
383.0	HOUSE REGULATORS	58-R2.5	0	12,799,915	3,104,473	3,562,907	201,008	1.57%	43.9
385.0	INDUSTRIAL MEAS. & REG. STATION EQUIPMENT	40-R2	0	2,750,416	626,381	705,890	62,416	2.27%	30.9
386.1	MISC. PROPERTY ON CUSTOMER'S PREMISES	15-R3	0	1,680	1,680	1,680	-	0.00%	-
387.2	OTHER EQUIPMENT	30-R3	0	1,785,360	493,740	562,854	44,414	2.49%	21.7
TOTAL DISTRIBUTION PLANT				**548,934,689**	**142,177,275**	**157,138,254**	**11,047,813**	**2.01%**	
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	45-R2	0	15,766,936	4,479,705	5,478,822	302,626	1.92%	32.2
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	307,608	184,956	127,853	60,397	19.63%	6.0
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	18,699	2,488	2,828	3,620	19.36%	4.3
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	20-R1	10	450,168	189,548	371,635	2,224	0.49%	10.6
392.2	TRANSPORTATION EQUIPMENT	10-L2	20	12,856,198	3,940,863	2,982,809	1,245,756	9.69%	6.2
393.0	STORES EQUIPMENT	30-SQ	0	103,298	39,829	32,134	4,184	4.05%	18.4
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	7,859,822	2,022,141	2,229,659	363,050	4.62%	14.9
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	36,373	26,667	26,707	1,811	4.98%	5.3
395.0	LABORATORY EQUIPMENT	20-SQ	0	316,786	116,700	59,620	43,180	13.63%	12.6
396.1	POWER OPERATED EQUIPMENT - TRAILERS	25-L2	30	1,306,142	242,246	555,146	16,911	1.29%	18.4
396.2	POWER OPERATED EQUIPMENT	3-L1	85	9,040,554	687,840	(2,072,744)	2,755,719	30.48%	1.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	1,190,544	661,093	620,243	89,145	7.49%	6.7
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	461,355	331,382	318,207	36,061	7.82%	4.2
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	128,459	60,170	43,271	16,317	12.70%	5.3
397.8	NETWORK EQUIPMENT	5-SQ	0	40,306	13,469	10,267	9,534	23.65%	3.3
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	71,705	26,324	(26,865)	6,011	8.38%	15.8
TOTAL GENERAL PLANT				**49,954,953**	**13,025,422**	**10,759,592**	**4,956,546**	**9.92%**	
TOTAL GAS PLANT STUDIED				**598,889,642**	**155,202,697**	**167,897,846**	**16,004,359**	**2.67%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			10,496,877					
374.1	LAND			1,202,798					
386.2	CNG REFUELING STATION			-					
387.1	CATHODIC PROTECTION EQUIPMENT			-					
389.0	LAND & LAND RIGHTS GENERAL			2,603,081					
TOTAL PLANT				613,192,398					

MONTANA-DAKOTA UTILITIES CO. - GAS PLANT

TABLE 1B. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN GAS PLANT AS OF DECEMBER 31, 2021

- COST OF REMOVAL -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE
DISTRIBUTION PLANT								
374.2	RIGHTS OF WAY	65-R3	0	1,286,382	-	13,754	(314)	-0.02%
375.0	DISTR. MEAS & REG STATION STRUCTURES	55-R3	0	1,707,340	-	207,196	(9,547)	-0.56%
376.0	MAINS	55-R3	-55	278,503,430	37,890,520	26,789,922	3,310,130	1.19%
378.0	MEAS & REG STATION EQUIP-GENERAL	50-R2	-30	5,144,890	364,101	344,025	31,101	0.60%
379.0	MEAS & REG STATION EQUIP-CITY GATE	45-R2.5	-5	11,726,166	96,310	215,959	8,748	0.07%
380.0	SERVICES	50-R2.5	-100	148,582,913	32,488,870	65,502,227	1,758,360	1.18%
381.0	METERS & METER INSTALLATIONS	31-R3	-20	84,646,197	6,559,083	486,229	1,468,656	1.74%
383.0	HOUSE REGULATORS	58-R2.5	-5	12,799,915	155,224	13,667	17,106	0.13%
385.0	INDUSTRIAL MEAS. & REG. STATION EQUIPMENT	40-R2	-10	2,750,416	62,638	78,152	5,804	0.21%
386.1	MISC. PROPERTY ON CUSTOMER'S PREMISES	15-R3	0	1,680	-	-	-	0.00%
387.2	OTHER EQUIPMENT	30-R3	0	1,785,360	-	-	-	0.00%
TOTAL DISTRIBUTION PLANT				**548,934,689**	**77,616,746**	**93,651,132**	**6,590,044**	**1.20%**
GENERAL PLANT								
390.0	STRUCTURES & IMPROVEMENTS	45-R2	0	15,766,936	-	722,850	(25,083)	-0.16%
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	307,608	-	-	-	0.00%
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	18,699	-	-	-	0.00%
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	20-R1	0	450,168	-	-	-	0.00%
392.2	TRANSPORTATION EQUIPMENT	10-L2	0	12,856,198	-	-	-	0.00%
393.0	STORES EQUIPMENT	30-SQ	0	103,298	-	-	-	0.00%
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	7,859,822	-	-	-	0.00%
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	36,373	-	-	-	0.00%
395.0	LABORATORY EQUIPMENT	20-SQ	0	316,786	-	-	-	0.00%
396.1	POWER OPERATED EQUIPMENT - TRAILERS	25-L2	0	1,306,142	-	-	-	0.00%
396.2	POWER OPERATED EQUIPMENT	3-L1	0	9,040,554	-	-	-	0.00%
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	1,190,544	-	-	-	0.00%
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	461,355	-	-	-	0.00%
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	128,459	-	-	-	0.00%
397.8	NETWORK EQUIPMENT	5-SQ	0	40,306	-	-	-	0.00%
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	71,705	-	-	-	0.00%
TOTAL GENERAL PLANT				**49,954,953**	**0**	**722,850**	**(25,083)**	**-0.05%**
TOTAL GAS PLANT STUDIED				**598,889,642**	**77,616,746**	**94,373,981**	**6,564,961**	**1.10%**
PLANT NOT STUDIED								
303.0	MISCELLANEOUS INTANGIBLE PLANT			10,496,877				
374.1	LAND			1,202,798				
386.2	CNG REFUELING STATION			-				
387.1	CATHODIC PROTECTION EQUIPMENT			-				
389.0	LAND & LAND RIGHTS GENERAL			2,603,081				
TOTAL PLANT				613,192,398				

SECTION 6

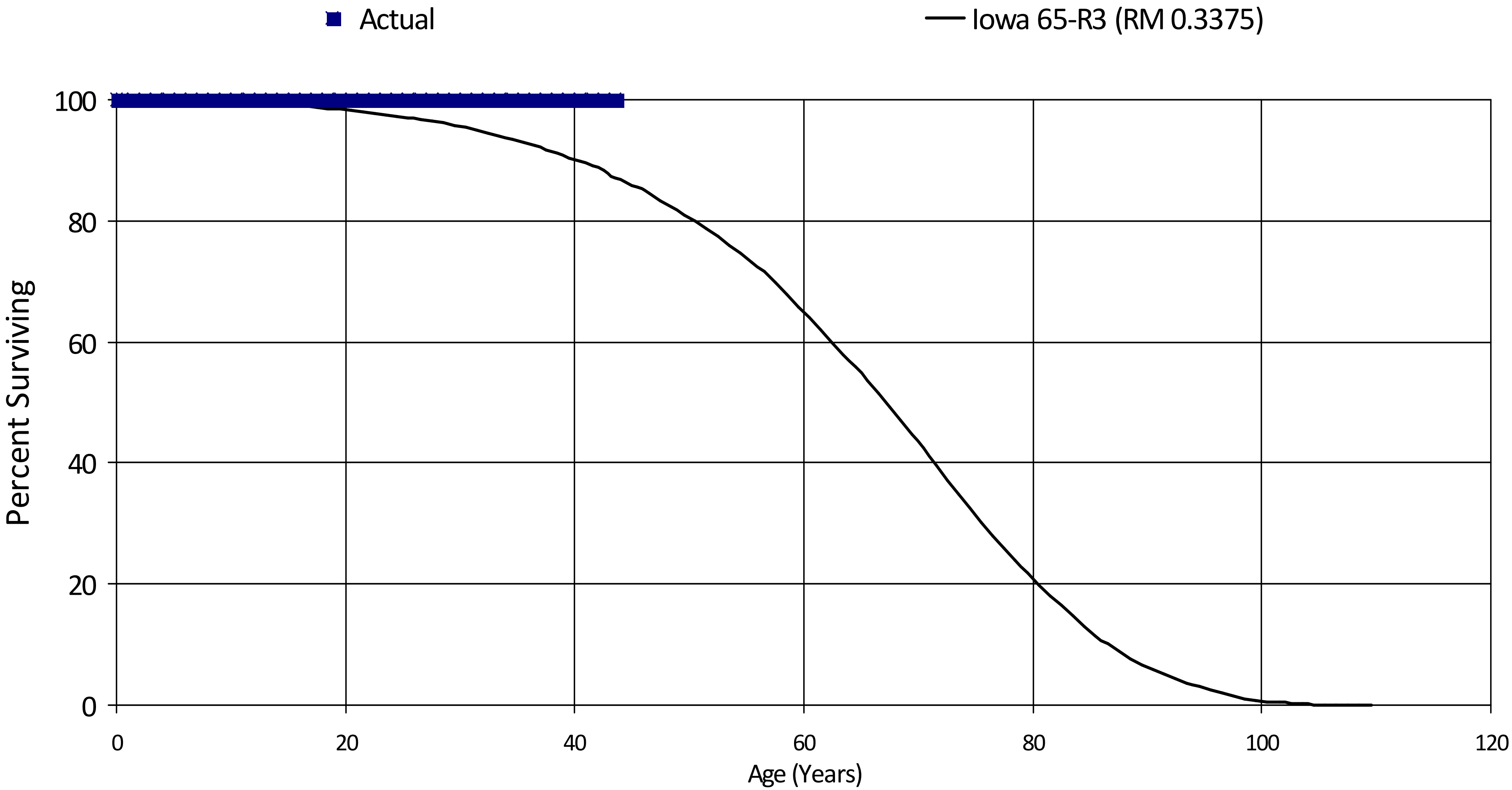
6 RETIREMENT RATE ANALYSIS

MDU Gas

Account 374.20 - Distribution Plant - Land Rights

Placement Band - 1977 - 2021 Experience Band - 2003 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 374.20 - Distribution Plant - Land Rights

Placement Band - 1977 - 2021   Experience Band - 2003 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,286,447	0	0.00000	1.00000	100.00
0.5	1,286,447	0	0.00000	1.00000	100.00
1.5	1,286,447	0	0.00000	1.00000	100.00
2.5	1,286,447	0	0.00000	1.00000	100.00
3.5	502,241	65	0.00013	0.99987	100.00
4.5	502,175	0	0.00000	1.00000	99.99
5.5	501,306	0	0.00000	1.00000	99.99
6.5	431,148	0	0.00000	1.00000	99.99
7.5	427,193	0	0.00000	1.00000	99.99
8.5	427,193	0	0.00000	1.00000	99.99
9.5	377,467	0	0.00000	1.00000	99.99
10.5	299,784	0	0.00000	1.00000	99.99
11.5	294,868	0	0.00000	1.00000	99.99
12.5	286,272	0	0.00000	1.00000	99.99
13.5	271,218	0	0.00000	1.00000	99.99
14.5	166,016	0	0.00000	1.00000	99.99
15.5	133,535	0	0.00000	1.00000	99.99
16.5	121,788	0	0.00000	1.00000	99.99
17.5	96,888	0	0.00000	1.00000	99.99
18.5	95,392	0	0.00000	1.00000	99.99
19.5	89,445	0	0.00000	1.00000	99.99
20.5	88,027	0	0.00000	1.00000	99.99
21.5	80,906	0	0.00000	1.00000	99.99
22.5	80,803	0	0.00000	1.00000	99.99
23.5	80,379	0	0.00000	1.00000	99.99
24.5	80,369	0	0.00000	1.00000	99.99
25.5	77,552	0	0.00000	1.00000	99.99
26.5	76,281	0	0.00000	1.00000	99.99

MDU Gas

Account 374.20 - Distribution Plant - Land Rights

Placement Band - 1977 - 2021   Experience Band - 2003 - 2021

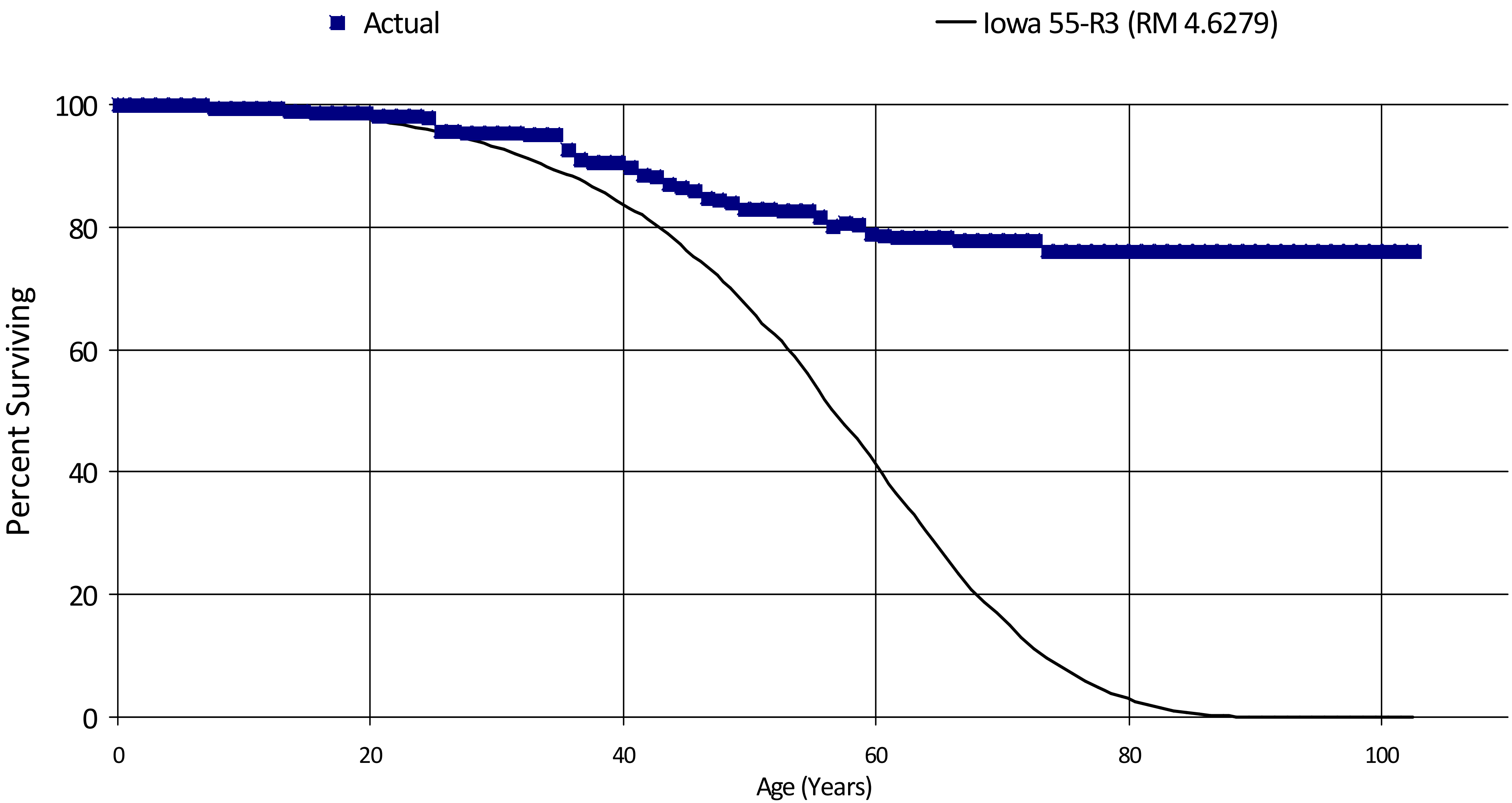
27.5	73,803	0	0.00000	1.00000	99.99
28.5	73,803	0	0.00000	1.00000	99.99
29.5	72,910	0	0.00000	1.00000	99.99
30.5	72,702	0	0.00000	1.00000	99.99
31.5	71,335	0	0.00000	1.00000	99.99
32.5	71,282	0	0.00000	1.00000	99.99
33.5	71,177	0	0.00000	1.00000	99.99
34.5	68,452	0	0.00000	1.00000	99.99
35.5	63,631	0	0.00000	1.00000	99.99
36.5	62,111	0	0.00000	1.00000	99.99
37.5	58,329	0	0.00000	1.00000	99.99
38.5	56,573	0	0.00000	1.00000	99.99
39.5	47,180	0	0.00000	1.00000	99.99
40.5	45,923	0	0.00000	1.00000	99.99
41.5	44,727	0	0.00000	1.00000	99.99
42.5	44,023	0	0.00000	1.00000	99.99
43.5	11,087	0	0.00000	1.00000	99.99
	Totals:	65			

MDU Gas

Account 375.00 - Distribution Plant - Structures & Improvements

Placement Band - 1918 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 375.00 - Distribution Plant - Structures & Improvements

Placement Band - 1918 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,787,999	0	0.00000	1.00000	100.00
0.5	1,677,048	0	0.00000	1.00000	100.00
1.5	1,654,250	0	0.00000	1.00000	100.00
2.5	1,629,790	771	0.00047	0.99953	100.00
3.5	1,603,017	0	0.00000	1.00000	99.95
4.5	1,522,696	0	0.00000	1.00000	99.95
5.5	1,500,252	0	0.00000	1.00000	99.95
6.5	1,103,280	4,564	0.00414	0.99586	99.95
7.5	859,012	0	0.00000	1.00000	99.54
8.5	821,600	0	0.00000	1.00000	99.54
9.5	763,783	0	0.00000	1.00000	99.54
10.5	632,686	956	0.00151	0.99849	99.54
11.5	621,050	0	0.00000	1.00000	99.39
12.5	621,050	1,856	0.00299	0.99701	99.39
13.5	584,214	0	0.00000	1.00000	99.09
14.5	581,746	1,970	0.00339	0.99661	99.09
15.5	569,847	0	0.00000	1.00000	98.75
16.5	555,897	0	0.00000	1.00000	98.75
17.5	551,787	0	0.00000	1.00000	98.75
18.5	529,637	0	0.00000	1.00000	98.75
19.5	529,637	3,370	0.00636	0.99364	98.75
20.5	526,267	0	0.00000	1.00000	98.12
21.5	525,587	0	0.00000	1.00000	98.12
22.5	525,587	0	0.00000	1.00000	98.12
23.5	523,413	1,079	0.00206	0.99794	98.12
24.5	509,850	11,887	0.02331	0.97669	97.92
25.5	495,549	0	0.00000	1.00000	95.64
26.5	509,332	1,213	0.00238	0.99762	95.64

MDU Gas

Account 375.00 - Distribution Plant - Structures & Improvements

Placement Band - 1918 - 2021   Experience Band - 1995 - 2021

27.5	439,926	0	0.00000	1.00000	95.41
28.5	396,850	0	0.00000	1.00000	95.41
29.5	383,303	284	0.00074	0.99926	95.41
30.5	369,601	0	0.00000	1.00000	95.34
31.5	368,148	721	0.00196	0.99804	95.34
32.5	359,773	0	0.00000	1.00000	95.15
33.5	358,760	0	0.00000	1.00000	95.15
34.5	358,333	9,653	0.02694	0.97306	95.15
35.5	335,017	5,125	0.01530	0.98470	92.59
36.5	303,346	1,613	0.00532	0.99468	91.17
37.5	295,287	0	0.00000	1.00000	90.68
38.5	299,029	350	0.00117	0.99883	90.68
39.5	289,132	2,494	0.00863	0.99137	90.57
40.5	286,127	3,523	0.01231	0.98769	89.79
41.5	281,786	779	0.00276	0.99724	88.68
42.5	278,117	4,669	0.01679	0.98321	88.44
43.5	273,448	1,630	0.00596	0.99404	86.96
44.5	271,818	950	0.00349	0.99651	86.44
45.5	270,868	3,929	0.01451	0.98549	86.14
46.5	265,314	938	0.00354	0.99646	84.89
47.5	261,133	1,757	0.00673	0.99327	84.59
48.5	256,426	3,423	0.01335	0.98665	84.02
49.5	249,857	0	0.00000	1.00000	82.90
50.5	244,705	0	0.00000	1.00000	82.90
51.5	234,097	344	0.00147	0.99853	82.90
52.5	227,561	0	0.00000	1.00000	82.78
53.5	221,054	0	0.00000	1.00000	82.78
54.5	214,950	2,483	0.01155	0.98845	82.78
55.5	207,086	3,839	0.01854	0.98146	81.82
56.5	195,887	-1,237	-0.00631	1.00631	80.30
57.5	191,242	670	0.00350	0.99650	80.81

MDU Gas

Account 375.00 - Distribution Plant - Structures & Improvements

Placement Band - 1918 - 2021   Experience Band - 1995 - 2021

58.5	173,780	3,253	0.01872	0.98128	80.53
59.5	147,943	664	0.00449	0.99551	79.02
60.5	136,071	315	0.00231	0.99769	78.67
61.5	123,078	0	0.00000	1.00000	78.49
62.5	113,432	0	0.00000	1.00000	78.49
63.5	99,794	0	0.00000	1.00000	78.49
64.5	88,718	0	0.00000	1.00000	78.49
65.5	59,502	373	0.00627	0.99373	78.49
66.5	51,463	0	0.00000	1.00000	78.00
67.5	32,329	0	0.00000	1.00000	78.00
68.5	29,194	0	0.00000	1.00000	78.00
69.5	24,377	0	0.00000	1.00000	78.00
70.5	20,333	0	0.00000	1.00000	78.00
71.5	19,374	0	0.00000	1.00000	78.00
72.5	18,821	450	0.02391	0.97609	78.00
73.5	17,487	0	0.00000	1.00000	76.14
74.5	16,602	0	0.00000	1.00000	76.14
75.5	15,717	0	0.00000	1.00000	76.14
76.5	15,717	0	0.00000	1.00000	76.14
77.5	15,717	0	0.00000	1.00000	76.14
78.5	15,717	0	0.00000	1.00000	76.14
79.5	15,717	0	0.00000	1.00000	76.14
80.5	15,717	0	0.00000	1.00000	76.14
81.5	14,832	0	0.00000	1.00000	76.14
82.5	13,969	0	0.00000	1.00000	76.14
83.5	13,127	0	0.00000	1.00000	76.14
84.5	12,306	0	0.00000	1.00000	76.14
85.5	11,504	0	0.00000	1.00000	76.14
86.5	10,722	0	0.00000	1.00000	76.14
87.5	9,959	0	0.00000	1.00000	76.14
88.5	9,215	0	0.00000	1.00000	76.14

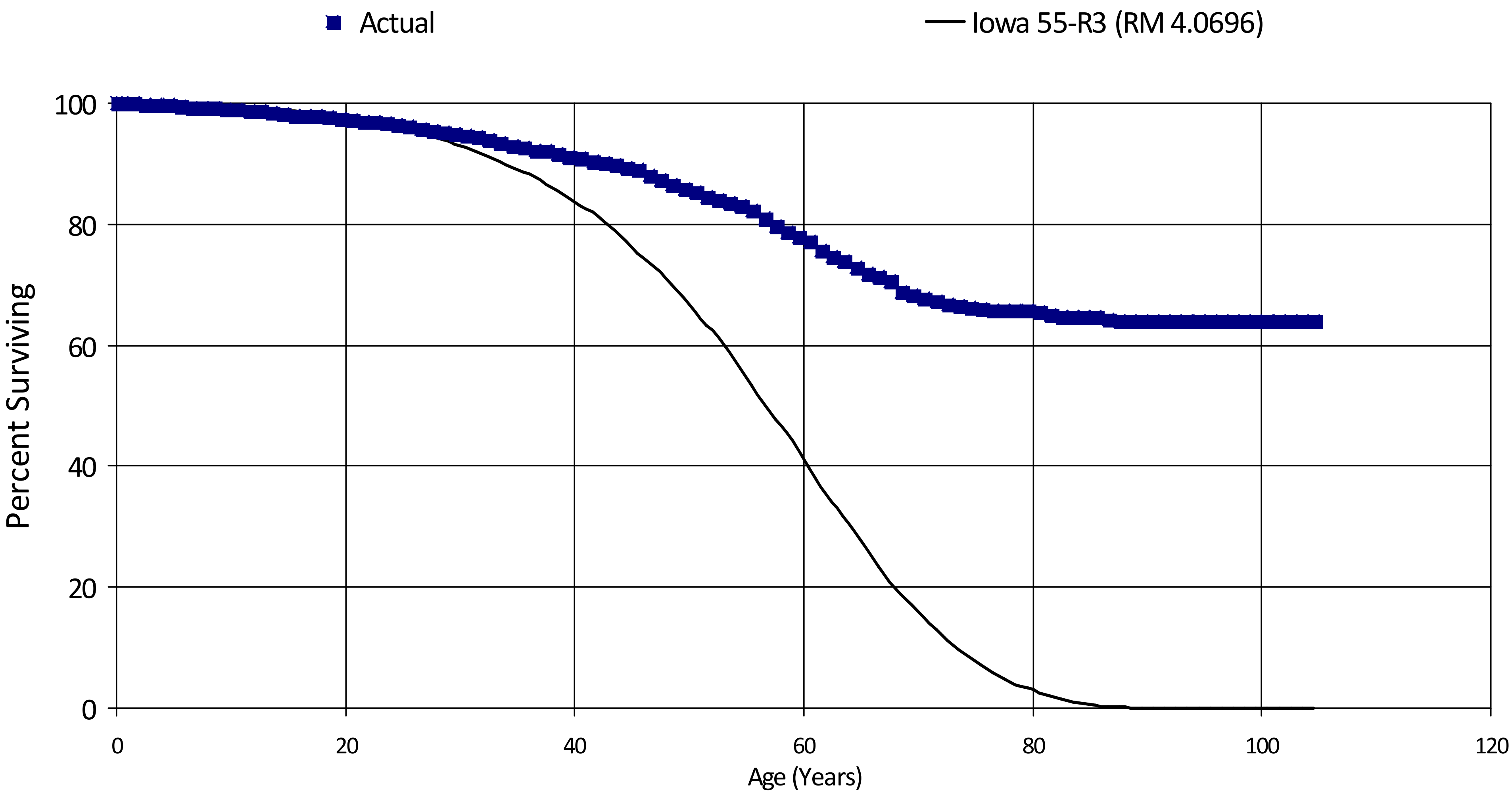
89.5	8,489	0	0.00000	1.00000	76.14
90.5	7,781	0	0.00000	1.00000	76.14
91.5	7,089	0	0.00000	1.00000	76.14
92.5	6,415	0	0.00000	1.00000	76.14
93.5	5,757	0	0.00000	1.00000	76.14
94.5	5,116	0	0.00000	1.00000	76.14
95.5	4,489	0	0.00000	1.00000	76.14
96.5	3,879	0	0.00000	1.00000	76.14
97.5	3,283	0	0.00000	1.00000	76.14
98.5	2,701	0	0.00000	1.00000	76.14
99.5	2,134	0	0.00000	1.00000	76.14
100.5	1,581	0	0.00000	1.00000	76.14
101.5	1,041	0	0.00000	1.00000	76.14
102.5	514	0	0.00000	1.00000	76.14
	Totals:	80,658			

MDU Gas

Account 376.00 - Distribution Plant - Mains

Placement Band - 1916 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 376.00 - Distribution Plant - Mains

Placement Band - 1916 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	289,580,288	9,329	0.00003	0.99997	100.00
0.5	272,772,142	184,249	0.00068	0.99932	100.00
1.5	259,644,406	318,620	0.00123	0.99877	99.93
2.5	240,324,991	122,861	0.00051	0.99949	99.81
3.5	217,955,116	304,585	0.00140	0.99860	99.76
4.5	207,520,882	260,382	0.00125	0.99875	99.62
5.5	199,479,931	319,717	0.00160	0.99840	99.50
6.5	187,285,551	144,451	0.00077	0.99923	99.34
7.5	150,985,622	160,437	0.00106	0.99894	99.26
8.5	138,229,932	111,208	0.00080	0.99920	99.15
9.5	122,045,581	168,728	0.00138	0.99862	99.07
10.5	115,922,529	97,897	0.00084	0.99916	98.93
11.5	111,773,589	192,489	0.00172	0.99828	98.85
12.5	108,488,813	148,228	0.00137	0.99863	98.68
13.5	101,073,136	300,208	0.00297	0.99703	98.54
14.5	97,472,114	161,824	0.00166	0.99834	98.25
15.5	93,709,593	99,915	0.00107	0.99893	98.09
16.5	88,852,345	111,404	0.00125	0.99875	97.99
17.5	85,109,519	171,385	0.00201	0.99799	97.87
18.5	81,645,835	180,129	0.00221	0.99779	97.67
19.5	78,711,762	169,556	0.00215	0.99785	97.45
20.5	76,573,961	222,491	0.00291	0.99709	97.24
21.5	74,577,253	100,933	0.00135	0.99865	96.96
22.5	72,916,691	100,698	0.00138	0.99862	96.83
23.5	71,233,735	195,145	0.00274	0.99726	96.70
24.5	69,245,048	175,058	0.00253	0.99747	96.44
25.5	67,072,117	278,632	0.00415	0.99585	96.20
26.5	65,484,029	227,397	0.00347	0.99653	95.80

MDU Gas

Account 376.00 - Distribution Plant - Mains

Placement Band - 1916 - 2021 Experience Band - 1995 - 2021

27.5	60,456,636	111,560	0.00185	0.99815	95.47
28.5	52,988,318	136,709	0.00258	0.99742	95.29
29.5	50,546,823	157,091	0.00311	0.99689	95.04
30.5	48,804,608	229,766	0.00471	0.99529	94.74
31.5	47,409,404	169,576	0.00358	0.99642	94.29
32.5	46,302,317	209,607	0.00453	0.99547	93.95
33.5	44,898,389	308,402	0.00687	0.99313	93.52
34.5	43,087,484	166,398	0.00386	0.99614	92.88
35.5	40,837,871	138,551	0.00339	0.99661	92.52
36.5	38,960,846	83,961	0.00216	0.99784	92.21
37.5	37,548,214	205,970	0.00549	0.99451	92.01
38.5	35,659,460	149,563	0.00419	0.99581	91.50
39.5	33,579,259	131,135	0.00391	0.99609	91.12
40.5	31,614,223	105,772	0.00335	0.99665	90.76
41.5	29,456,452	76,781	0.00261	0.99739	90.46
42.5	27,838,418	98,825	0.00355	0.99645	90.22
43.5	26,989,048	133,512	0.00495	0.99505	89.90
44.5	26,270,798	140,021	0.00533	0.99467	89.45
45.5	24,998,189	218,209	0.00873	0.99127	88.97
46.5	23,972,924	239,467	0.00999	0.99001	88.19
47.5	23,264,420	217,274	0.00934	0.99066	87.31
48.5	22,161,993	172,373	0.00778	0.99222	86.49
49.5	20,206,712	154,124	0.00763	0.99237	85.82
50.5	19,364,661	175,922	0.00908	0.99092	85.17
51.5	16,476,537	98,171	0.00596	0.99404	84.40
52.5	15,705,183	83,295	0.00530	0.99470	83.90
53.5	14,867,205	91,816	0.00618	0.99382	83.46
54.5	14,173,174	134,631	0.00950	0.99050	82.94
55.5	13,545,597	207,034	0.01528	0.98472	82.15
56.5	12,674,524	194,106	0.01531	0.98469	80.89
57.5	11,752,677	128,954	0.01097	0.98903	79.65

MDU Gas

Account 376.00 - Distribution Plant - Mains

Placement Band - 1916 - 2021   Experience Band - 1995 - 2021

58.5	10,894,550	108,041	0.00992	0.99008	78.78
59.5	9,905,979	119,865	0.01210	0.98790	78.00
60.5	9,175,527	162,002	0.01766	0.98234	77.06
61.5	8,303,434	105,570	0.01271	0.98729	75.70
62.5	7,606,875	94,707	0.01245	0.98755	74.74
63.5	7,046,449	85,019	0.01207	0.98793	73.81
64.5	6,597,867	99,792	0.01512	0.98488	72.92
65.5	5,825,400	37,586	0.00645	0.99355	71.82
66.5	5,003,754	61,209	0.01223	0.98777	71.36
67.5	4,476,247	102,002	0.02279	0.97721	70.49
68.5	3,986,815	37,358	0.00937	0.99063	68.88
69.5	3,439,344	29,581	0.00860	0.99140	68.23
70.5	3,088,189	22,755	0.00737	0.99263	67.64
71.5	2,683,238	19,760	0.00736	0.99264	67.14
72.5	2,552,456	5,248	0.00206	0.99794	66.65
73.5	2,433,018	10,182	0.00418	0.99582	66.51
74.5	2,320,647	8,954	0.00386	0.99614	66.23
75.5	2,200,311	5,439	0.00247	0.99753	65.97
76.5	2,196,484	3,026	0.00138	0.99862	65.81
77.5	2,193,570	2,224	0.00101	0.99899	65.72
78.5	2,191,394	1,023	0.00047	0.99953	65.65
79.5	2,190,393	6,198	0.00283	0.99717	65.62
80.5	2,191,494	15,785	0.00720	0.99280	65.43
81.5	2,062,108	4,112	0.00199	0.99801	64.96
82.5	1,954,843	4,735	0.00242	0.99758	64.83
83.5	1,845,046	8	0.00000	1.00000	64.67
84.5	1,736,468	473	0.00027	0.99973	64.67
85.5	1,630,009	14,161	0.00869	0.99131	64.65
86.5	1,525,962	542	0.00036	0.99964	64.09
87.5	1,424,216	2,496	0.00175	0.99825	64.07
88.5	1,322,985	475	0.00036	0.99964	63.96

MDU Gas

Account 376.00 - Distribution Plant - Mains

Placement Band - 1916 - 2021 Experience Band - 1995 - 2021

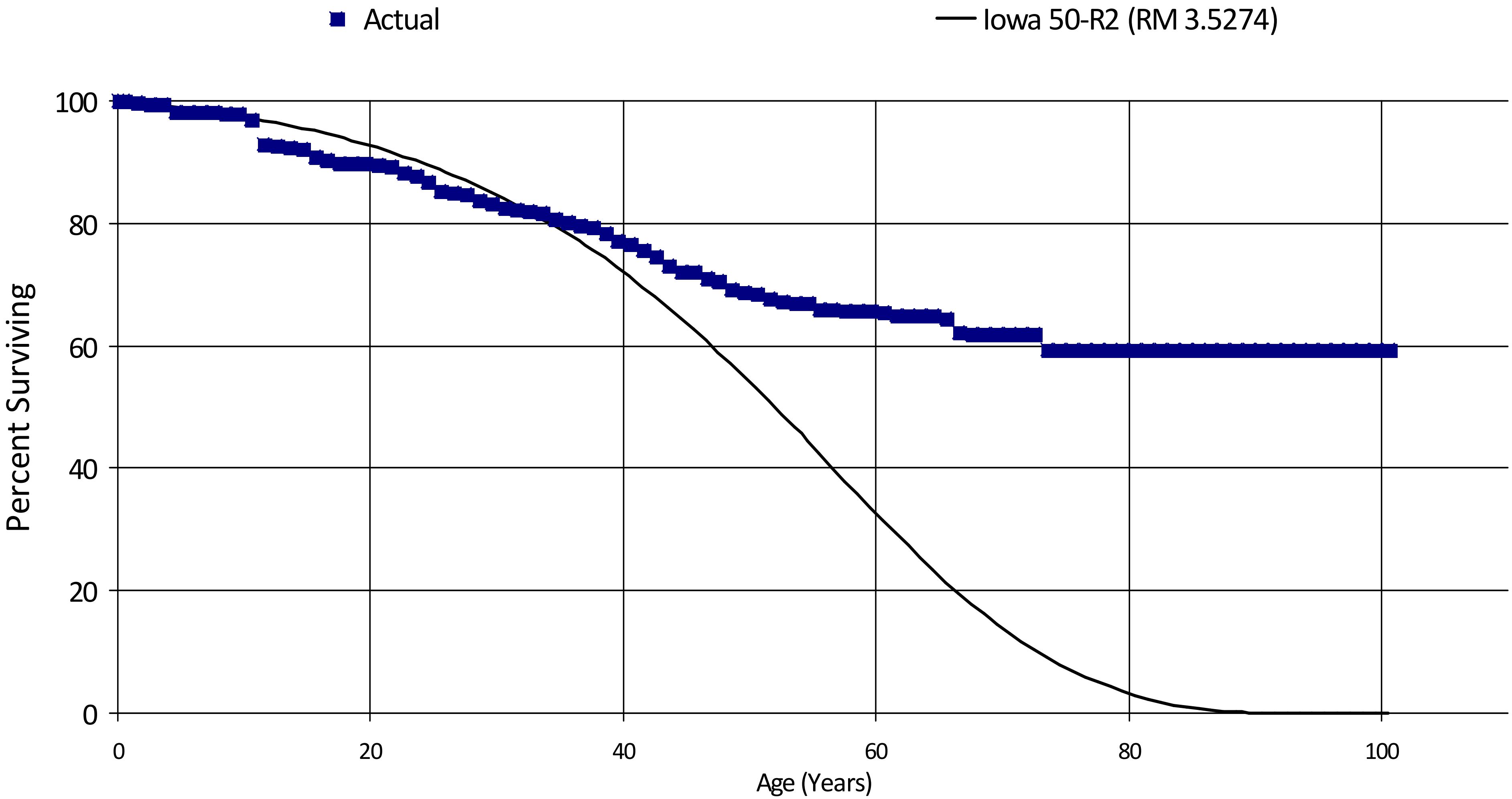
89.5	1,226,634	0	0.00000	1.00000	63.94
90.5	1,135,377	0	0.00000	1.00000	63.94
91.5	1,044,758	0	0.00000	1.00000	63.94
92.5	955,309	0	0.00000	1.00000	63.94
93.5	868,041	0	0.00000	1.00000	63.94
94.5	783,152	0	0.00000	1.00000	63.94
95.5	700,089	0	0.00000	1.00000	63.94
96.5	619,052	0	0.00000	1.00000	63.94
97.5	539,992	0	0.00000	1.00000	63.94
98.5	462,859	0	0.00000	1.00000	63.94
99.5	387,609	0	0.00000	1.00000	63.94
100.5	314,193	0	0.00000	1.00000	63.94
101.5	242,568	0	0.00000	1.00000	63.94
102.5	172,690	0	0.00000	1.00000	63.94
103.5	104,517	0	0.00000	1.00000	63.94
104.5	38,006	0	0.00000	1.00000	63.94
	Totals:	11,076,860			

MDU Gas

Account 378.00 - Distribution Plant - Meas. & Reg. Station Equip - General

Placement Band - 1920 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 378.00 - Distribution Plant - Meas. & Reg. Station Equip - General

Placement Band - 1920 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,680,886	0	0.00000	1.00000	100.00
0.5	4,944,399	14,586	0.00295	0.99705	100.00
1.5	4,526,773	9,904	0.00219	0.99781	99.70
2.5	4,386,714	1,371	0.00031	0.99969	99.48
3.5	3,989,578	50,519	0.01266	0.98734	99.45
4.5	3,769,378	510	0.00014	0.99986	98.19
5.5	3,651,958	2,696	0.00074	0.99926	98.18
6.5	3,362,399	0	0.00000	1.00000	98.11
7.5	3,234,556	2,995	0.00093	0.99907	98.11
8.5	3,078,485	0	0.00000	1.00000	98.02
9.5	2,845,218	28,020	0.00985	0.99015	98.02
10.5	2,331,395	97,010	0.04161	0.95839	97.05
11.5	2,165,927	7,900	0.00365	0.99635	93.01
12.5	2,142,112	5,265	0.00246	0.99754	92.67
13.5	1,952,374	5,427	0.00278	0.99722	92.44
14.5	1,875,623	28,891	0.01540	0.98460	92.18
15.5	1,762,044	9,744	0.00553	0.99447	90.76
16.5	1,632,884	5,674	0.00347	0.99653	90.26
17.5	1,482,964	1,347	0.00091	0.99909	89.95
18.5	1,447,995	0	0.00000	1.00000	89.87
19.5	1,391,434	4,798	0.00345	0.99655	89.87
20.5	1,361,981	3,139	0.00230	0.99770	89.56
21.5	1,335,076	16,922	0.01267	0.98733	89.35
22.5	1,288,531	4,545	0.00353	0.99647	88.22
23.5	1,258,120	16,700	0.01327	0.98673	87.91
24.5	1,183,998	18,740	0.01583	0.98417	86.74
25.5	1,161,592	5,005	0.00431	0.99569	85.37
26.5	1,167,696	4,233	0.00363	0.99637	85.00

MDU Gas

Account 378.00 - Distribution Plant - Meas. & Reg. Station Equip - General

Placement Band - 1920 - 2021 Experience Band - 1995 - 2021

27.5	1,117,548	12,114	0.01084	0.98916	84.69
28.5	1,037,777	5,416	0.00522	0.99478	83.77
29.5	1,005,446	11,327	0.01127	0.98873	83.33
30.5	980,950	2,265	0.00231	0.99769	82.39
31.5	975,020	3,644	0.00374	0.99626	82.20
32.5	949,462	2,142	0.00226	0.99774	81.89
33.5	924,319	10,317	0.01116	0.98884	81.70
34.5	899,459	5,771	0.00642	0.99358	80.79
35.5	877,512	5,880	0.00670	0.99330	80.27
36.5	858,157	4,189	0.00488	0.99512	79.73
37.5	834,348	9,632	0.01154	0.98846	79.34
38.5	797,372	13,391	0.01679	0.98321	78.42
39.5	747,647	4,581	0.00613	0.99387	77.10
40.5	740,400	10,492	0.01417	0.98583	76.63
41.5	698,181	7,469	0.01070	0.98930	75.54
42.5	684,156	15,542	0.02272	0.97728	74.73
43.5	655,473	7,887	0.01203	0.98797	73.03
44.5	620,870	1,614	0.00260	0.99740	72.15
45.5	575,419	6,944	0.01207	0.98793	71.96
46.5	545,191	4,261	0.00782	0.99218	71.09
47.5	494,589	8,821	0.01783	0.98217	70.53
48.5	472,511	4,143	0.00877	0.99123	69.27
49.5	452,289	189	0.00042	0.99958	68.66
50.5	430,511	6,079	0.01412	0.98588	68.63
51.5	400,329	2,697	0.00674	0.99326	67.66
52.5	377,519	908	0.00241	0.99759	67.20
53.5	362,290	143	0.00039	0.99961	67.04
54.5	352,978	4,992	0.01414	0.98586	67.01
55.5	336,484	983	0.00292	0.99708	66.06
56.5	309,915	350	0.00113	0.99887	65.87
57.5	298,507	-253	-0.00085	1.00085	65.80

58.5	285,330	1,081	0.00379	0.99621	65.86
59.5	269,338	613	0.00228	0.99772	65.61
60.5	250,678	1,782	0.00711	0.99289	65.46
61.5	223,744	0	0.00000	1.00000	64.99
62.5	207,099	0	0.00000	1.00000	64.99
63.5	196,249	170	0.00087	0.99913	64.99
64.5	190,926	1,314	0.00688	0.99312	64.93
65.5	175,570	6,291	0.03583	0.96417	64.48
66.5	149,121	319	0.00214	0.99786	62.17
67.5	135,535	0	0.00000	1.00000	62.04
68.5	130,258	0	0.00000	1.00000	62.04
69.5	122,803	0	0.00000	1.00000	62.04
70.5	129,094	0	0.00000	1.00000	62.04
71.5	113,355	0	0.00000	1.00000	62.04
72.5	108,163	4,560	0.04216	0.95784	62.04
73.5	96,521	0	0.00000	1.00000	59.42
74.5	91,328	0	0.00000	1.00000	59.42
75.5	86,136	0	0.00000	1.00000	59.42
76.5	86,136	0	0.00000	1.00000	59.42
77.5	86,136	0	0.00000	1.00000	59.42
78.5	86,136	0	0.00000	1.00000	59.42
79.5	86,136	0	0.00000	1.00000	59.42
80.5	86,136	0	0.00000	1.00000	59.42
81.5	80,944	0	0.00000	1.00000	59.42
82.5	75,878	0	0.00000	1.00000	59.42
83.5	70,936	0	0.00000	1.00000	59.42
84.5	66,114	0	0.00000	1.00000	59.42
85.5	61,410	0	0.00000	1.00000	59.42
86.5	56,821	0	0.00000	1.00000	59.42
87.5	52,344	0	0.00000	1.00000	59.42
88.5	47,976	0	0.00000	1.00000	59.42

MDU Gas

Account 378.00 - Distribution Plant - Meas. & Reg. Station Equip - General

Placement Band - 1920 - 2021 Experience Band - 1995 - 2021

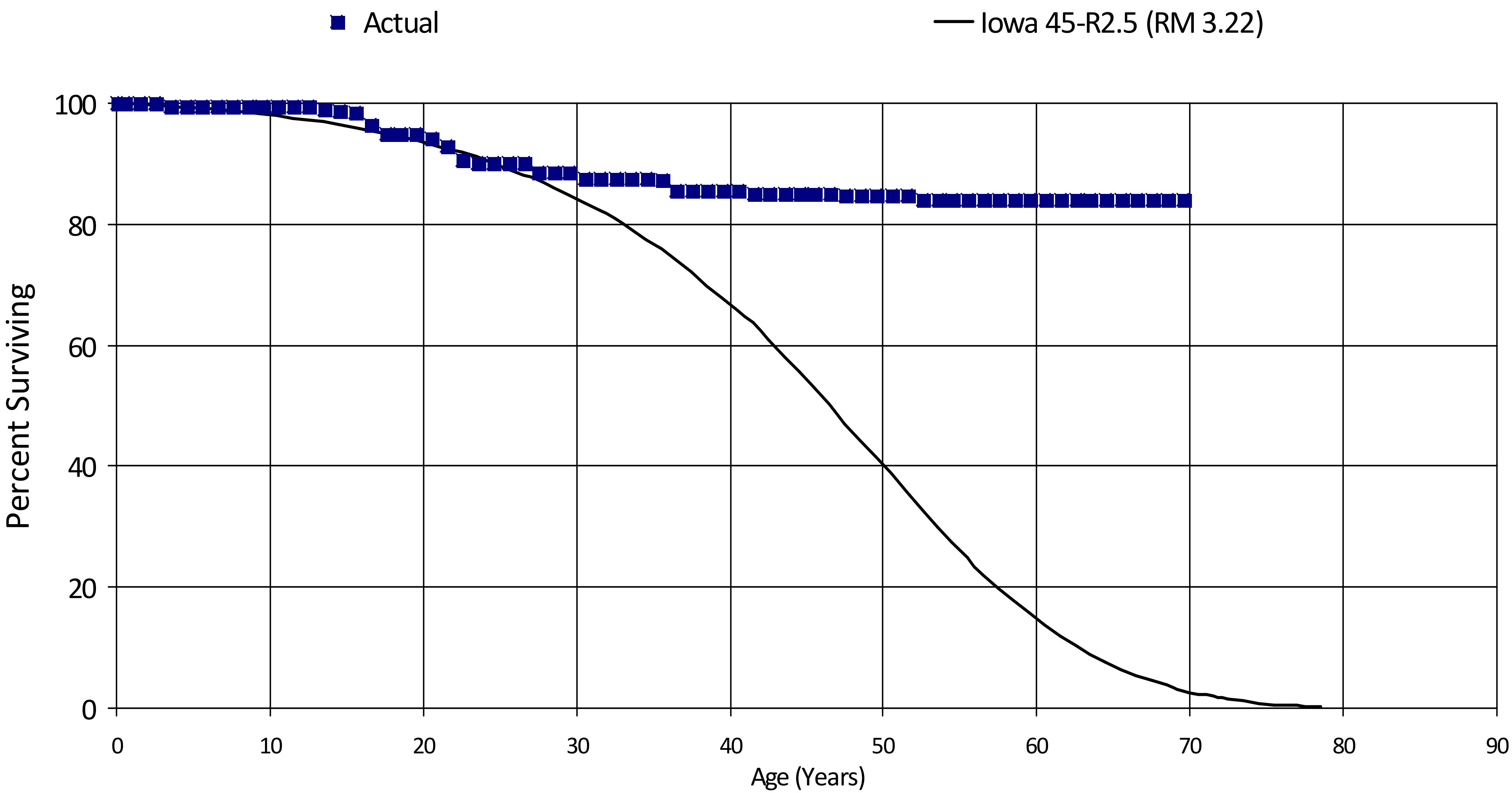
89.5	43,714	0	0.00000	1.00000	59.42
90.5	39,557	0	0.00000	1.00000	59.42
91.5	35,500	0	0.00000	1.00000	59.42
92.5	31,543	0	0.00000	1.00000	59.42
93.5	27,682	0	0.00000	1.00000	59.42
94.5	23,916	0	0.00000	1.00000	59.42
95.5	20,241	0	0.00000	1.00000	59.42
96.5	16,656	0	0.00000	1.00000	59.42
97.5	13,158	0	0.00000	1.00000	59.42
98.5	9,746	0	0.00000	1.00000	59.42
99.5	6,417	0	0.00000	1.00000	59.42
100.5	3,169	0	0.00000	1.00000	59.42
	Totals:	536,001			

MDU Gas

Account 379.00 - Distribution Plant - Meas. & Reg. Station Equip - City Gate

Placement Band - 1951 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 379.00 - Distribution Plant - Meas. & Reg. Station Equip - City Gate

Placement Band - 1951 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	11,919,701	0	0.00000	1.00000	100.00
0.5	11,366,755	0	0.00000	1.00000	100.00
1.5	11,362,728	1,429	0.00013	0.99987	100.00
2.5	10,132,563	39,578	0.00391	0.99609	99.99
3.5	7,847,033	8,268	0.00105	0.99895	99.60
4.5	6,977,354	0	0.00000	1.00000	99.50
5.5	6,283,271	0	0.00000	1.00000	99.50
6.5	5,072,334	0	0.00000	1.00000	99.50
7.5	4,449,044	0	0.00000	1.00000	99.50
8.5	2,409,770	2,446	0.00102	0.99898	99.50
9.5	1,726,715	0	0.00000	1.00000	99.40
10.5	1,299,745	0	0.00000	1.00000	99.40
11.5	1,169,143	0	0.00000	1.00000	99.40
12.5	1,163,218	4,756	0.00409	0.99591	99.40
13.5	1,135,018	3,340	0.00294	0.99706	98.99
14.5	1,131,677	2,594	0.00229	0.99771	98.70
15.5	1,123,564	23,768	0.02115	0.97885	98.47
16.5	1,099,797	15,454	0.01405	0.98595	96.39
17.5	1,079,157	0	0.00000	1.00000	95.04
18.5	1,055,985	0	0.00000	1.00000	95.04
19.5	1,055,985	9,848	0.00933	0.99067	95.04
20.5	1,046,136	14,000	0.01338	0.98662	94.15
21.5	1,032,136	26,327	0.02551	0.97449	92.89
22.5	1,005,810	3,713	0.00369	0.99631	90.52
23.5	996,896	80	0.00008	0.99992	90.19
24.5	954,544	0	0.00000	1.00000	90.18
25.5	954,544	0	0.00000	1.00000	90.18
26.5	934,115	15,278	0.01636	0.98364	90.18

MDU Gas

Account 379.00 - Distribution Plant - Meas. & Reg. Station Equip - City Gate

Placement Band - 1951 - 2021 Experience Band - 1995 - 2021

27.5	685,023	0	0.00000	1.00000	88.70
28.5	463,609	0	0.00000	1.00000	88.70
29.5	463,609	6,280	0.01355	0.98645	88.70
30.5	456,779	0	0.00000	1.00000	87.50
31.5	455,735	0	0.00000	1.00000	87.50
32.5	455,735	0	0.00000	1.00000	87.50
33.5	455,735	0	0.00000	1.00000	87.50
34.5	455,713	1,470	0.00323	0.99677	87.50
35.5	453,802	8,335	0.01837	0.98163	87.22
36.5	445,467	0	0.00000	1.00000	85.62
37.5	442,127	903	0.00204	0.99796	85.62
38.5	428,732	0	0.00000	1.00000	85.45
39.5	417,889	0	0.00000	1.00000	85.45
40.5	407,343	1,664	0.00409	0.99591	85.45
41.5	386,959	500	0.00129	0.99871	85.10
42.5	383,465	0	0.00000	1.00000	84.99
43.5	372,522	0	0.00000	1.00000	84.99
44.5	370,078	0	0.00000	1.00000	84.99
45.5	360,513	0	0.00000	1.00000	84.99
46.5	356,429	1,039	0.00292	0.99708	84.99
47.5	335,100	0	0.00000	1.00000	84.74
48.5	319,906	0	0.00000	1.00000	84.74
49.5	298,275	0	0.00000	1.00000	84.74
50.5	286,344	0	0.00000	1.00000	84.74
51.5	261,488	2,391	0.00914	0.99086	84.74
52.5	248,058	0	0.00000	1.00000	83.97
53.5	237,986	0	0.00000	1.00000	83.97
54.5	221,778	0	0.00000	1.00000	83.97
55.5	218,653	75	0.00034	0.99966	83.97
56.5	196,667	0	0.00000	1.00000	83.94
57.5	152,999	0	0.00000	1.00000	83.94

MDU Gas

Account 379.00 - Distribution Plant - Meas. & Reg. Station Equip - City Gate

Placement Band - 1951 - 2021   Experience Band - 1995 - 2021

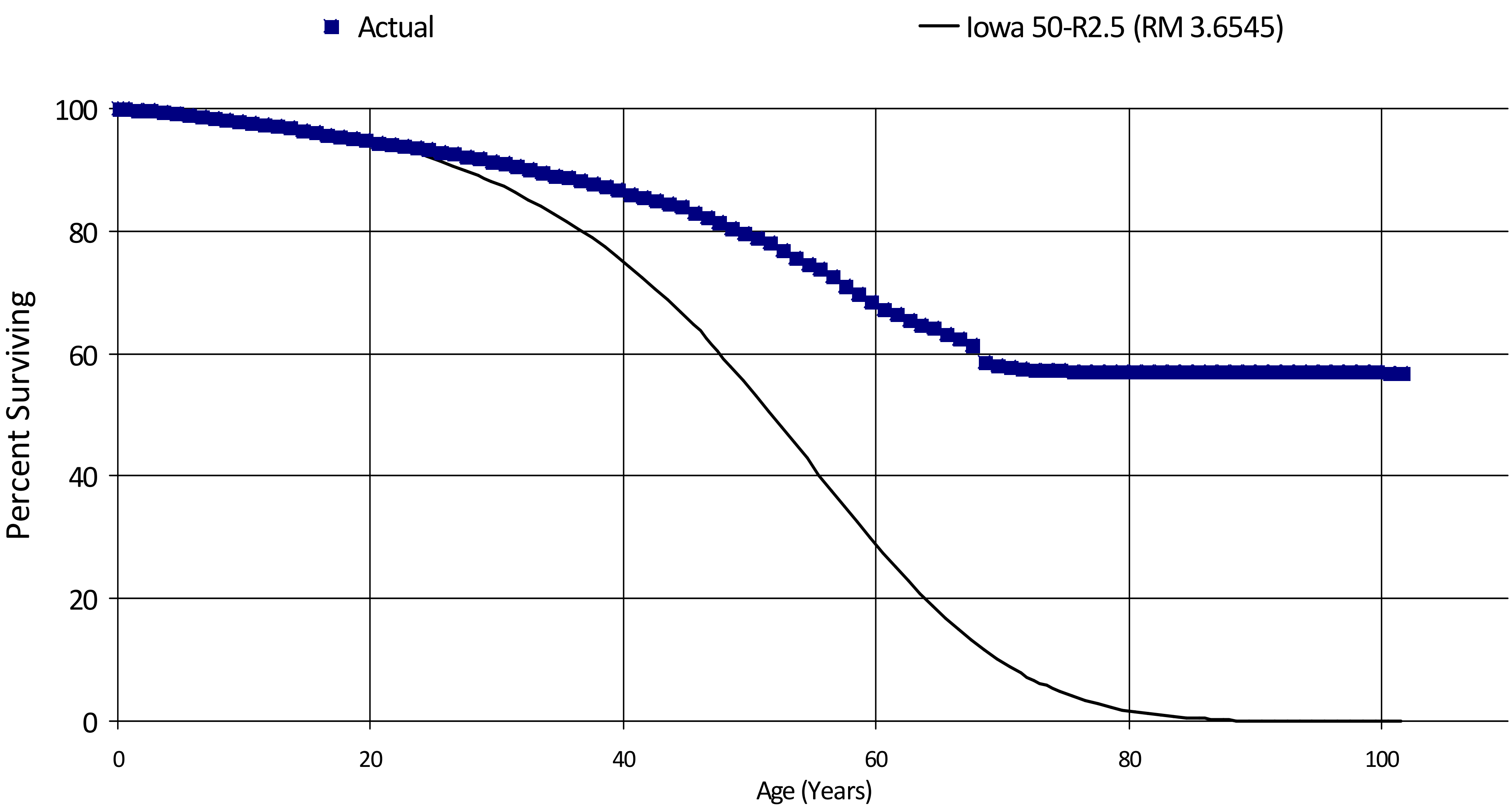
58.5	135,909	0	0.00000	1.00000	83.94
59.5	114,833	0	0.00000	1.00000	83.94
60.5	94,839	0	0.00000	1.00000	83.94
61.5	94,839	0	0.00000	1.00000	83.94
62.5	94,839	0	0.00000	1.00000	83.94
63.5	92,449	0	0.00000	1.00000	83.94
64.5	86,007	0	0.00000	1.00000	83.94
65.5	83,366	0	0.00000	1.00000	83.94
66.5	72,277	0	0.00000	1.00000	83.94
67.5	55,767	0	0.00000	1.00000	83.94
68.5	42,976	0	0.00000	1.00000	83.94
69.5	32,046	0	0.00000	1.00000	83.94
	Totals:	193,536			

MDU Gas

Account 380.00 - Distribution Plant - Services

Placement Band - 1901 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 380.00 - Distribution Plant - Services

Placement Band - 1901 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	155,488,513	14,244	0.00009	0.99991	100.00
0.5	143,151,275	235,022	0.00164	0.99836	99.99
1.5	133,652,563	267,940	0.00200	0.99800	99.83
2.5	120,390,523	262,094	0.00218	0.99782	99.63
3.5	110,612,597	260,661	0.00236	0.99764	99.41
4.5	102,642,555	246,846	0.00240	0.99760	99.18
5.5	96,165,359	202,463	0.00211	0.99789	98.94
6.5	88,560,869	209,180	0.00236	0.99764	98.73
7.5	80,409,231	219,338	0.00273	0.99727	98.50
8.5	72,207,946	142,943	0.00198	0.99802	98.23
9.5	64,323,175	237,091	0.00369	0.99631	98.04
10.5	58,905,028	125,460	0.00213	0.99787	97.68
11.5	55,065,125	152,798	0.00277	0.99723	97.47
12.5	51,669,963	169,527	0.00328	0.99672	97.20
13.5	47,813,156	221,401	0.00463	0.99537	96.88
14.5	44,627,393	162,747	0.00365	0.99635	96.43
15.5	41,609,925	130,109	0.00313	0.99687	96.08
16.5	38,746,414	127,557	0.00329	0.99671	95.78
17.5	36,102,731	132,966	0.00368	0.99632	95.46
18.5	33,854,035	107,557	0.00318	0.99682	95.11
19.5	32,364,961	107,817	0.00333	0.99667	94.81
20.5	31,075,619	93,390	0.00301	0.99699	94.49
21.5	29,914,404	86,108	0.00288	0.99712	94.21
22.5	28,829,650	100,537	0.00349	0.99651	93.94
23.5	27,521,303	81,764	0.00297	0.99703	93.61
24.5	26,010,929	99,470	0.00382	0.99618	93.33
25.5	24,414,965	89,388	0.00366	0.99634	92.97
26.5	23,674,525	101,537	0.00429	0.99571	92.63

MDU Gas

Account 380.00 - Distribution Plant - Services

Placement Band - 1901 - 2021   Experience Band - 1995 - 2021

27.5	21,578,782	90,138	0.00418	0.99582	92.23
28.5	20,519,452	88,017	0.00429	0.99571	91.84
29.5	19,597,198	96,523	0.00493	0.99507	91.45
30.5	18,802,391	83,471	0.00444	0.99556	91.00
31.5	18,206,097	81,656	0.00449	0.99551	90.60
32.5	17,643,868	102,203	0.00579	0.99421	90.19
33.5	16,968,712	90,774	0.00535	0.99465	89.67
34.5	16,307,337	67,673	0.00415	0.99585	89.19
35.5	15,553,021	82,258	0.00529	0.99471	88.82
36.5	14,599,201	70,862	0.00485	0.99515	88.35
37.5	13,741,541	97,115	0.00707	0.99293	87.92
38.5	12,728,617	82,171	0.00646	0.99354	87.30
39.5	11,859,763	80,542	0.00679	0.99321	86.74
40.5	11,063,861	69,136	0.00625	0.99375	86.15
41.5	10,184,474	65,342	0.00642	0.99358	85.61
42.5	9,411,942	57,144	0.00607	0.99393	85.06
43.5	8,849,420	57,456	0.00649	0.99351	84.54
44.5	8,299,903	89,291	0.01076	0.98924	83.99
45.5	7,530,777	83,716	0.01112	0.98888	83.09
46.5	6,920,341	60,355	0.00872	0.99128	82.17
47.5	6,265,361	67,849	0.01083	0.98917	81.45
48.5	5,738,910	56,822	0.00990	0.99010	80.57
49.5	5,163,023	59,102	0.01145	0.98855	79.77
50.5	4,840,113	44,436	0.00918	0.99082	78.86
51.5	4,038,787	57,812	0.01431	0.98569	78.14
52.5	3,813,396	70,054	0.01837	0.98163	77.02
53.5	3,600,432	41,947	0.01165	0.98835	75.61
54.5	3,405,631	40,242	0.01182	0.98818	74.73
55.5	3,225,593	54,775	0.01698	0.98302	73.85
56.5	3,012,139	60,872	0.02021	0.97979	72.60
57.5	2,765,502	53,983	0.01952	0.98048	71.13

MDU Gas

Account 380.00 - Distribution Plant - Services

Placement Band - 1901 - 2021 Experience Band - 1995 - 2021

58.5	2,561,815	45,974	0.01795	0.98205	69.74
59.5	2,330,462	41,325	0.01773	0.98227	68.49
60.5	2,160,677	27,480	0.01272	0.98728	67.28
61.5	2,021,575	24,815	0.01228	0.98772	66.42
62.5	1,854,859	24,124	0.01301	0.98699	65.60
63.5	1,708,210	15,651	0.00916	0.99084	64.75
64.5	1,567,332	23,868	0.01523	0.98477	64.16
65.5	1,364,687	14,505	0.01063	0.98937	63.18
66.5	1,263,980	21,159	0.01674	0.98326	62.51
67.5	1,131,966	51,280	0.04530	0.95470	61.46
68.5	997,906	10,699	0.01072	0.98928	58.68
69.5	875,708	2,745	0.00313	0.99687	58.05
70.5	782,198	1,925	0.00246	0.99754	57.87
71.5	724,106	4,031	0.00557	0.99443	57.73
72.5	685,683	892	0.00130	0.99870	57.41
73.5	651,336	1,077	0.00165	0.99835	57.34
74.5	616,594	549	0.00089	0.99911	57.25
75.5	582,539	301	0.00052	0.99948	57.20
76.5	582,578	291	0.00050	0.99950	57.17
77.5	582,421	54	0.00009	0.99991	57.14
78.5	582,507	324	0.00056	0.99944	57.13
79.5	582,268	251	0.00043	0.99957	57.10
80.5	582,352	88	0.00015	0.99985	57.08
81.5	547,839	0	0.00000	1.00000	57.07
82.5	513,715	0	0.00000	1.00000	57.07
83.5	480,238	23	0.00005	0.99995	57.07
84.5	447,612	33	0.00007	0.99993	57.07
85.5	415,695	96	0.00023	0.99977	57.07
86.5	384,592	95	0.00025	0.99975	57.06
87.5	354,181	54	0.00015	0.99985	57.05
88.5	324,572	88	0.00027	0.99973	57.04

MDU Gas

Account 380.00 - Distribution Plant - Services

Placement Band - 1901 - 2021   Experience Band - 1995 - 2021

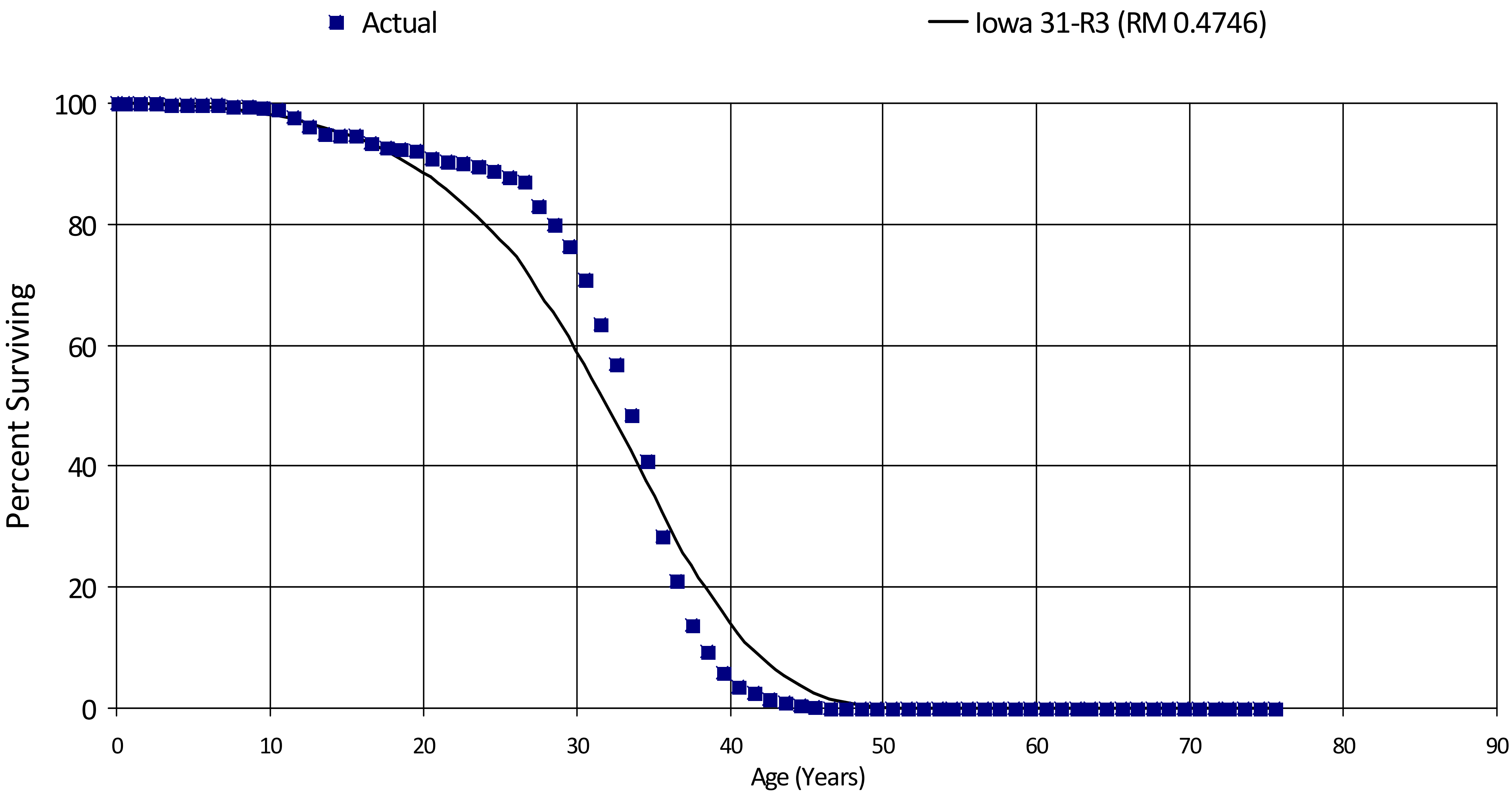
89.5	295,633	0	0.00000	1.00000	57.02
90.5	267,505	0	0.00000	1.00000	57.02
91.5	240,589	0	0.00000	1.00000	57.02
92.5	213,767	0	0.00000	1.00000	57.02
93.5	187,631	0	0.00000	1.00000	57.02
94.5	162,101	0	0.00000	1.00000	57.02
95.5	137,194	0	0.00000	1.00000	57.02
96.5	112,894	0	0.00000	1.00000	57.02
97.5	89,186	0	0.00000	1.00000	57.02
98.5	66,057	32	0.00048	0.99952	57.02
99.5	43,461	33	0.00076	0.99924	56.99
100.5	21,413	0	0.00000	1.00000	56.95
101.5	0	21	0.00000	0.00000	56.95
	Totals:	6,905,575			

MDU Gas

Account 381.00 - Distribution Plant - Meters

Placement Band - 1921 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 381.00 - Distribution Plant - Meters

Placement Band - 1921 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	99,717,965	10,408	0.00010	0.99990	100.00
0.5	97,580,262	23,967	0.00025	0.99975	99.99
1.5	92,165,197	47,067	0.00051	0.99949	99.97
2.5	86,358,984	63,560	0.00074	0.99926	99.92
3.5	82,028,690	40,779	0.00050	0.99950	99.85
4.5	79,534,421	33,732	0.00042	0.99958	99.80
5.5	77,331,091	54,355	0.00070	0.99930	99.76
6.5	73,692,508	59,415	0.00081	0.99919	99.69
7.5	70,264,716	121,400	0.00173	0.99827	99.61
8.5	67,517,916	123,686	0.00183	0.99817	99.44
9.5	64,021,617	148,674	0.00232	0.99768	99.26
10.5	60,994,879	869,477	0.01425	0.98575	99.03
11.5	59,122,852	912,311	0.01543	0.98457	97.62
12.5	57,576,030	674,160	0.01171	0.98829	96.11
13.5	47,254,010	104,582	0.00221	0.99779	94.98
14.5	39,028,293	67,907	0.00174	0.99826	94.77
15.5	36,981,835	471,206	0.01274	0.98726	94.61
16.5	34,154,519	254,099	0.00744	0.99256	93.40
17.5	32,582,993	98,462	0.00302	0.99698	92.71
18.5	31,175,818	98,957	0.00317	0.99683	92.43
19.5	29,584,880	390,287	0.01319	0.98681	92.14
20.5	27,569,670	137,187	0.00498	0.99502	90.92
21.5	25,732,501	124,412	0.00483	0.99517	90.47
22.5	23,960,107	138,921	0.00580	0.99420	90.03
23.5	22,609,141	179,299	0.00793	0.99207	89.51
24.5	21,435,915	209,655	0.00978	0.99022	88.80
25.5	20,105,476	203,233	0.01011	0.98989	87.93
26.5	5,215,481	249,934	0.04792	0.95208	87.04

MDU Gas

Account 381.00 - Distribution Plant - Meters

Placement Band - 1921 - 2021   Experience Band - 1995 - 2021

27.5	5,115,403	187,702	0.03669	0.96331	82.87
28.5	5,042,462	215,488	0.04273	0.95727	79.83
29.5	4,912,085	355,812	0.07244	0.92756	76.42
30.5	4,639,987	491,726	0.10598	0.89402	70.88
31.5	4,284,585	442,007	0.10316	0.89684	63.37
32.5	3,864,720	561,260	0.14523	0.85477	56.83
33.5	3,330,652	532,326	0.15983	0.84017	48.58
34.5	2,837,957	855,766	0.30154	0.69846	40.82
35.5	2,314,704	611,546	0.26420	0.73580	28.51
36.5	1,974,454	689,197	0.34906	0.65094	20.98
37.5	1,617,821	517,790	0.32005	0.67995	13.66
38.5	1,464,501	540,506	0.36907	0.63093	9.29
39.5	1,095,770	434,664	0.39667	0.60333	5.86
40.5	1,043,729	321,475	0.30801	0.69199	3.54
41.5	905,748	326,440	0.36041	0.63959	2.45
42.5	717,124	287,397	0.40076	0.59924	1.57
43.5	537,200	267,374	0.49772	0.50228	0.94
44.5	360,211	214,809	0.59634	0.40366	0.47
45.5	258,136	214,460	0.83080	0.16920	0.19
46.5	188,134	205,770	1.09374	-0.09374	0.03
47.5	131,845	166,591	1.26354	-0.26354	0.00
48.5	46,444	129,298	2.78397	-1.78397	0.00
49.5	19,456	106,627	5.48038	-4.48038	0.00
50.5	-23,594	86,210	-3.65389	4.65389	0.00
51.5	-15,171	62,161	-4.09745	5.09745	0.00
52.5	-31,917	71,074	-2.22686	3.22686	0.00
53.5	-62,639	56,919	-0.90868	1.90868	0.00
54.5	-71,373	43,855	-0.61445	1.61445	0.00
55.5	-76,425	46,479	-0.60816	1.60816	0.00
56.5	-60,568	33,998	-0.56132	1.56132	0.00
57.5	-43,879	23,930	-0.54536	1.54536	0.00

MDU Gas

Account 381.00 - Distribution Plant - Meters

Placement Band - 1921 - 2021   Experience Band - 1995 - 2021

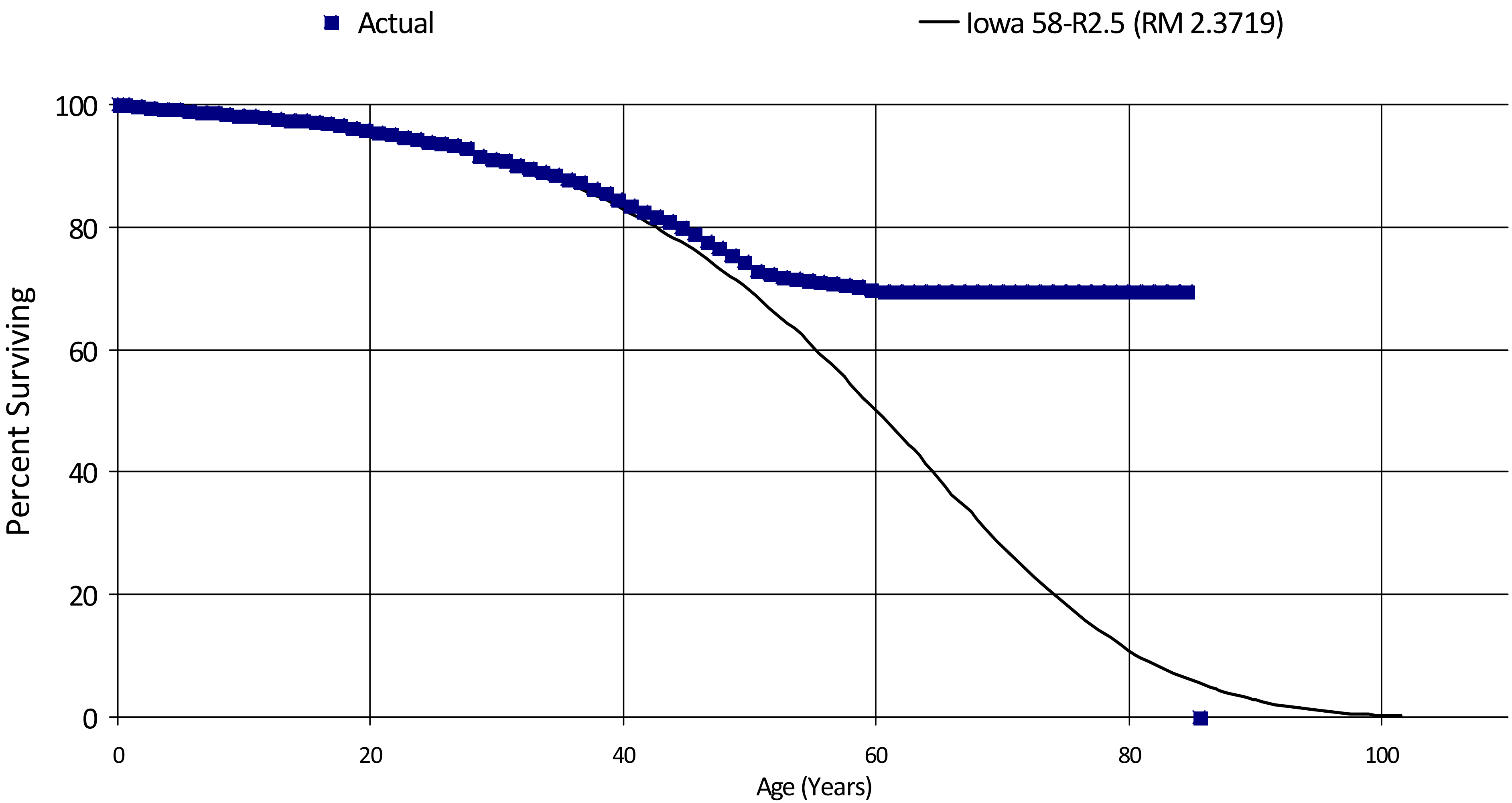
58.5	-33,382	26,138	-0.78299	1.78299	0.00
59.5	-12,473	24,221	-1.94182	2.94182	0.00
60.5	-4,629	3,769	-0.81429	1.81429	0.00
61.5	5,849	1,135	0.19406	0.80594	0.00
62.5	4,714	595	0.12622	0.87378	0.00
63.5	4,119	335	0.08134	0.91866	0.00
64.5	3,783	674	0.17816	0.82184	0.00
65.5	3,109	234	0.07527	0.92473	0.00
66.5	2,875	403	0.14018	0.85982	0.00
67.5	2,472	267	0.10801	0.89199	0.00
68.5	2,205	786	0.35647	0.64353	0.00
69.5	1,419	496	0.34964	0.65036	0.00
70.5	922	241	0.26135	0.73865	0.00
71.5	681	69	0.10128	0.89872	0.00
72.5	612	234	0.38220	0.61780	0.00
73.5	378	314	0.82968	0.17032	0.00
74.5	64	64	1.00063	-0.00063	0.00
75.5	0	0	0.00000	0.00000	0.00
	Totals:	15,071,764			

MDU Gas

Account 383.00 - Distribution Plant - Service Regulators

Placement Band - 1933 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 383.00 - Distribution Plant - Service Regulators

Placement Band - 1933 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,706,497	8,069	0.00059	0.99941	100.00
0.5	13,228,434	41,792	0.00316	0.99684	99.94
1.5	12,395,179	19,217	0.00155	0.99845	99.62
2.5	11,072,244	12,893	0.00116	0.99884	99.47
3.5	10,322,900	22,206	0.00215	0.99785	99.35
4.5	9,860,083	17,502	0.00178	0.99822	99.14
5.5	9,496,607	14,453	0.00152	0.99848	98.96
6.5	8,619,959	10,411	0.00121	0.99879	98.81
7.5	7,934,644	16,807	0.00212	0.99788	98.69
8.5	7,412,305	15,313	0.00207	0.99793	98.48
9.5	6,717,762	11,763	0.00175	0.99825	98.28
10.5	6,130,384	9,853	0.00161	0.99839	98.11
11.5	5,806,378	10,056	0.00173	0.99827	97.95
12.5	5,690,658	12,035	0.00211	0.99789	97.78
13.5	5,375,135	12,384	0.00230	0.99770	97.57
14.5	5,211,721	10,782	0.00207	0.99793	97.35
15.5	4,979,493	14,318	0.00288	0.99712	97.15
16.5	4,763,003	13,805	0.00290	0.99710	96.87
17.5	4,637,648	19,250	0.00415	0.99585	96.59
18.5	4,437,090	15,289	0.00345	0.99655	96.19
19.5	4,307,029	18,985	0.00441	0.99559	95.86
20.5	4,188,421	15,271	0.00365	0.99635	95.44
21.5	4,030,192	12,967	0.00322	0.99678	95.09
22.5	3,883,426	14,595	0.00376	0.99624	94.78
23.5	3,683,861	16,487	0.00448	0.99552	94.42
24.5	3,510,873	13,521	0.00385	0.99615	94.00
25.5	3,367,739	11,564	0.00343	0.99657	93.64
26.5	3,316,370	11,478	0.00346	0.99654	93.32

MDU Gas

Account 383.00 - Distribution Plant - Service Regulators

Placement Band - 1933 - 2021 Experience Band - 1995 - 2021

27.5	3,174,571	46,437	0.01463	0.98537	93.00
28.5	2,990,366	14,496	0.00485	0.99515	91.64
29.5	2,877,977	12,226	0.00425	0.99575	91.20
30.5	2,784,645	19,143	0.00687	0.99313	90.81
31.5	2,717,338	16,878	0.00621	0.99379	90.19
32.5	2,659,975	17,236	0.00648	0.99352	89.63
33.5	2,596,058	15,656	0.00603	0.99397	89.05
34.5	2,540,547	18,123	0.00713	0.99287	88.51
35.5	2,466,932	16,527	0.00670	0.99330	87.88
36.5	2,349,442	26,806	0.01141	0.98859	87.29
37.5	2,204,616	17,795	0.00807	0.99193	86.29
38.5	2,094,586	24,379	0.01164	0.98836	85.59
39.5	2,006,390	24,067	0.01200	0.98800	84.59
40.5	1,854,951	21,409	0.01154	0.98846	83.57
41.5	1,704,455	17,224	0.01011	0.98989	82.61
42.5	1,601,918	17,405	0.01087	0.98913	81.77
43.5	1,521,306	18,197	0.01196	0.98804	80.88
44.5	1,421,031	16,892	0.01189	0.98811	79.91
45.5	1,324,092	23,732	0.01792	0.98208	78.96
46.5	1,208,999	15,841	0.01310	0.98690	77.55
47.5	1,097,787	16,013	0.01459	0.98541	76.53
48.5	1,010,384	13,233	0.01310	0.98690	75.41
49.5	915,044	19,047	0.02082	0.97918	74.42
50.5	859,484	5,718	0.00665	0.99335	72.87
51.5	819,753	7,464	0.00911	0.99089	72.39
52.5	793,017	3,029	0.00382	0.99618	71.73
53.5	761,627	2,463	0.00323	0.99677	71.46
54.5	734,458	2,338	0.00318	0.99682	71.23
55.5	715,290	1,967	0.00275	0.99725	71.00
56.5	687,343	2,034	0.00296	0.99704	70.80
57.5	657,889	3,434	0.00522	0.99478	70.59

MDU Gas

Account 383.00 - Distribution Plant - Service Regulators

Placement Band - 1933 - 2021 Experience Band - 1995 - 2021

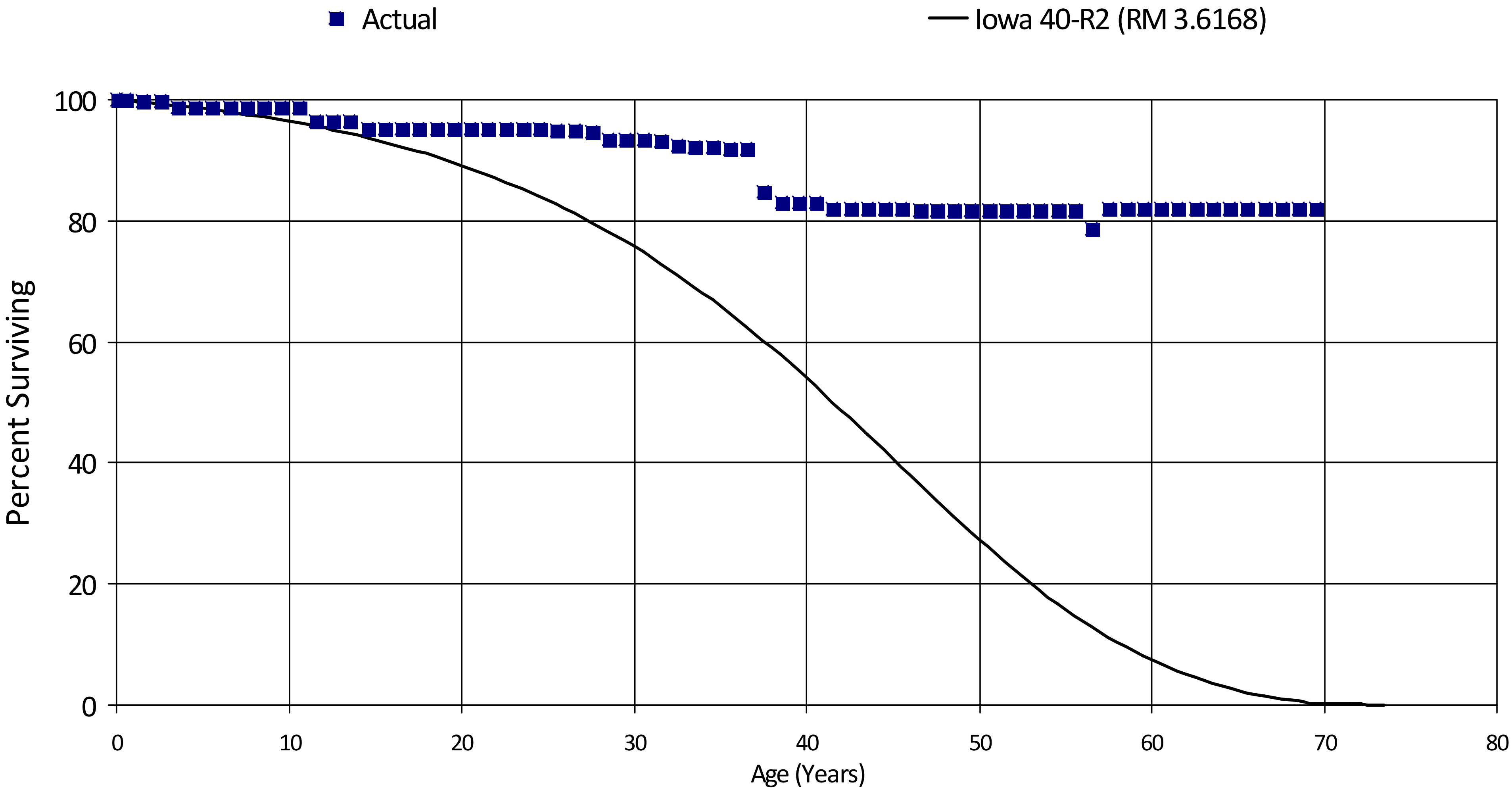
58.5	619,706	3,691	0.00596	0.99404	70.22
59.5	571,427	1,339	0.00234	0.99766	69.80
60.5	527,044	303	0.00057	0.99943	69.64
61.5	459,087	201	0.00044	0.99956	69.60
62.5	413,273	151	0.00037	0.99963	69.57
63.5	383,912	0	0.00000	1.00000	69.54
64.5	346,491	0	0.00000	1.00000	69.54
65.5	261,724	0	0.00000	1.00000	69.54
66.5	216,483	0	0.00000	1.00000	69.54
67.5	187,710	0	0.00000	1.00000	69.54
68.5	153,154	0	0.00000	1.00000	69.54
69.5	126,119	0	0.00000	1.00000	69.54
70.5	100,310	0	0.00000	1.00000	69.54
71.5	79,503	0	0.00000	1.00000	69.54
72.5	58,373	0	0.00000	1.00000	69.54
73.5	37,243	0	0.00000	1.00000	69.54
74.5	16,112	0	0.00000	1.00000	69.54
75.5	625	0	0.00000	1.00000	69.54
76.5	625	0	0.00000	1.00000	69.54
77.5	625	0	0.00000	1.00000	69.54
78.5	625	0	0.00000	1.00000	69.54
79.5	625	0	0.00000	1.00000	69.54
80.5	625	0	0.00000	1.00000	69.54
81.5	625	0	0.00000	1.00000	69.54
82.5	625	0	0.00000	1.00000	69.54
83.5	625	0	0.00000	1.00000	69.54
84.5	625	625	1.00054	-0.00054	69.54
85.5	0	0	0.00000	0.00000	-0.04
	Totals:	906,585			

MDU Gas

Account 385.00 - Distribution Plant - Industrial Meas. & Reg. Station Equipment

Placement Band - 1951 - 2021 Experience Band - 1996 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 385.00 - Distribution Plant - Industrial Meas. & Reg. Station Equipment

Placement Band - 1951 - 2021 Experience Band - 1996 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,840,306	0	0.00000	1.00000	100.00
0.5	2,646,886	3,440	0.00130	0.99870	100.00
1.5	2,366,298	3,256	0.00138	0.99862	99.87
2.5	1,993,723	20,478	0.01027	0.98973	99.73
3.5	1,878,585	0	0.00000	1.00000	98.71
4.5	1,772,552	0	0.00000	1.00000	98.71
5.5	1,752,593	0	0.00000	1.00000	98.71
6.5	1,679,690	0	0.00000	1.00000	98.71
7.5	932,838	0	0.00000	1.00000	98.71
8.5	806,733	0	0.00000	1.00000	98.71
9.5	806,733	0	0.00000	1.00000	98.71
10.5	806,733	18,176	0.02253	0.97747	98.71
11.5	788,557	0	0.00000	1.00000	96.49
12.5	788,557	0	0.00000	1.00000	96.49
13.5	635,518	7,894	0.01242	0.98758	96.49
14.5	627,623	0	0.00000	1.00000	95.29
15.5	579,562	0	0.00000	1.00000	95.29
16.5	579,562	0	0.00000	1.00000	95.29
17.5	571,101	0	0.00000	1.00000	95.29
18.5	515,662	0	0.00000	1.00000	95.29
19.5	514,156	0	0.00000	1.00000	95.29
20.5	507,405	0	0.00000	1.00000	95.29
21.5	504,220	0	0.00000	1.00000	95.29
22.5	494,466	0	0.00000	1.00000	95.29
23.5	478,529	0	0.00000	1.00000	95.29
24.5	466,141	1,778	0.00381	0.99619	95.29
25.5	436,250	0	0.00000	1.00000	94.93
26.5	409,950	1,530	0.00373	0.99627	94.93

MDU Gas

Account 385.00 - Distribution Plant - Industrial Meas. & Reg. Station Equipment

Placement Band - 1951 - 2021   Experience Band - 1996 - 2021

27.5	399,710	4,644	0.01162	0.98838	94.58
28.5	382,452	15	0.00004	0.99996	93.48
29.5	370,758	0	0.00000	1.00000	93.48
30.5	352,858	1,207	0.00342	0.99658	93.48
31.5	336,502	3,206	0.00953	0.99047	93.16
32.5	333,192	561	0.00168	0.99832	92.27
33.5	312,700	25	0.00008	0.99992	92.11
34.5	295,710	465	0.00157	0.99843	92.10
35.5	290,821	0	0.00000	1.00000	91.96
36.5	211,827	16,590	0.07832	0.92168	91.96
37.5	176,153	3,438	0.01952	0.98048	84.76
38.5	172,542	0	0.00000	1.00000	83.11
39.5	185,934	0	0.00000	1.00000	83.11
40.5	185,691	2,527	0.01361	0.98639	83.11
41.5	176,621	0	0.00000	1.00000	81.98
42.5	176,621	0	0.00000	1.00000	81.98
43.5	176,621	0	0.00000	1.00000	81.98
44.5	176,621	0	0.00000	1.00000	81.98
45.5	176,621	286	0.00162	0.99838	81.98
46.5	163,240	0	0.00000	1.00000	81.85
47.5	161,584	375	0.00232	0.99768	81.85
48.5	154,689	0	0.00000	1.00000	81.66
49.5	146,862	0	0.00000	1.00000	81.66
50.5	141,338	0	0.00000	1.00000	81.66
51.5	129,921	0	0.00000	1.00000	81.66
52.5	115,916	0	0.00000	1.00000	81.66
53.5	106,005	0	0.00000	1.00000	81.66
54.5	101,513	0	0.00000	1.00000	81.66
55.5	96,120	3,406	0.03543	0.96457	81.66
56.5	81,541	-3,406	-0.04177	1.04177	78.77
57.5	67,112	0	0.00000	1.00000	82.06

MDU Gas

Account 385.00 - Distribution Plant - Industrial Meas. & Reg. Station Equipment

Placement Band - 1951 - 2021   Experience Band - 1996 - 2021

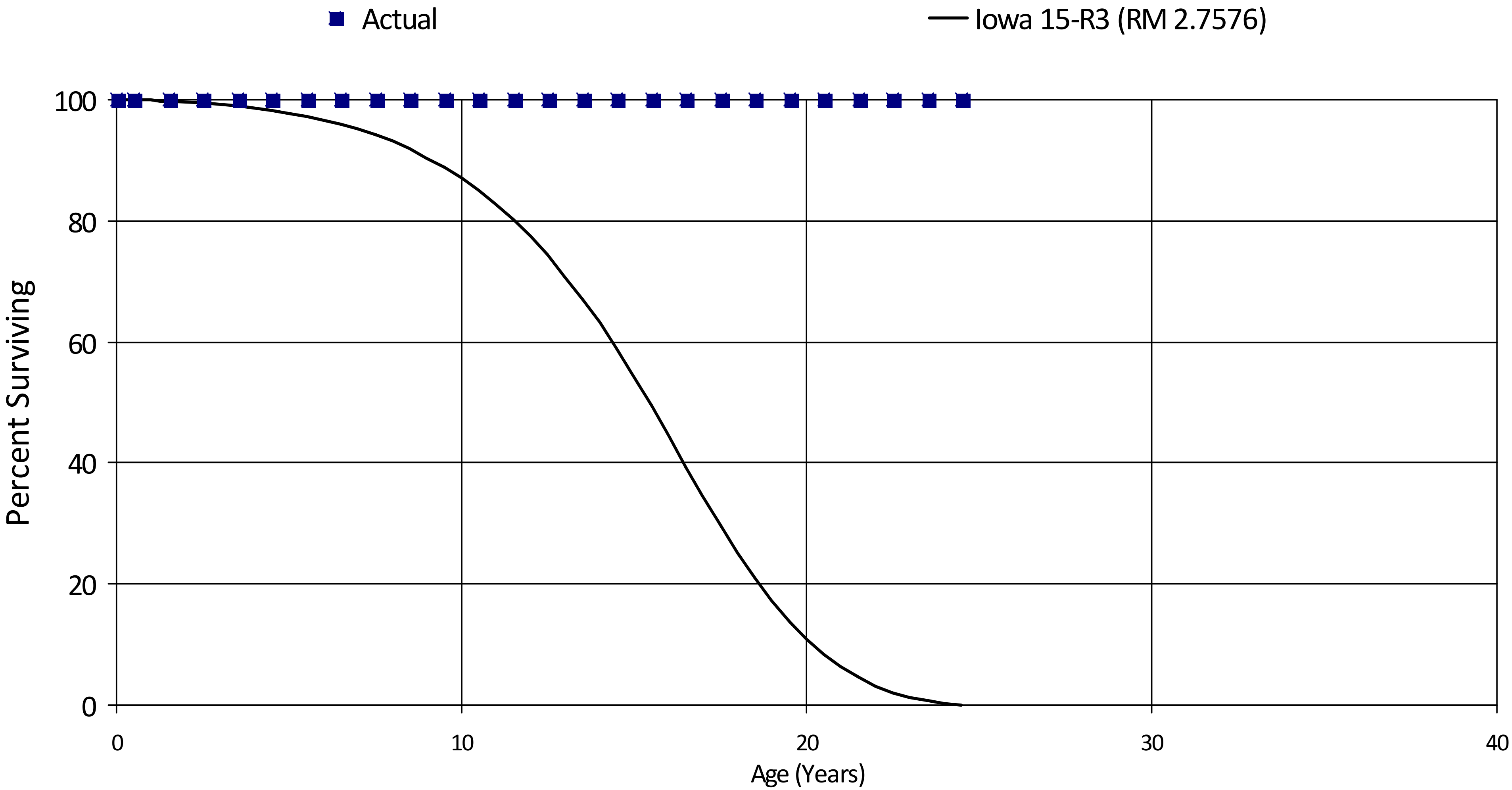
58.5	56,529	0	0.00000	1.00000	82.06
59.5	54,765	0	0.00000	1.00000	82.06
60.5	46,569	0	0.00000	1.00000	82.06
61.5	34,108	0	0.00000	1.00000	82.06
62.5	29,534	0	0.00000	1.00000	82.06
63.5	25,480	0	0.00000	1.00000	82.06
64.5	19,419	0	0.00000	1.00000	82.06
65.5	12,822	0	0.00000	1.00000	82.06
66.5	10,459	0	0.00000	1.00000	82.06
67.5	9,713	0	0.00000	1.00000	82.06
68.5	7,549	0	0.00000	1.00000	82.06
69.5	2,681	0	0.00000	1.00000	82.06
	Totals:	89,891			

MDU Gas

Account 386.10 - Distribution Plant - Misc. Property on Customers' Premises

Placement Band - 1996 - 2021   Experience Band - 2021 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 386.10 - Distribution Plant - Misc. Property on Customers' Premises

Placement Band - 1996 - 2021   Experience Band - 2021 - 2021

RETIREMENT RATE ANALYSIS

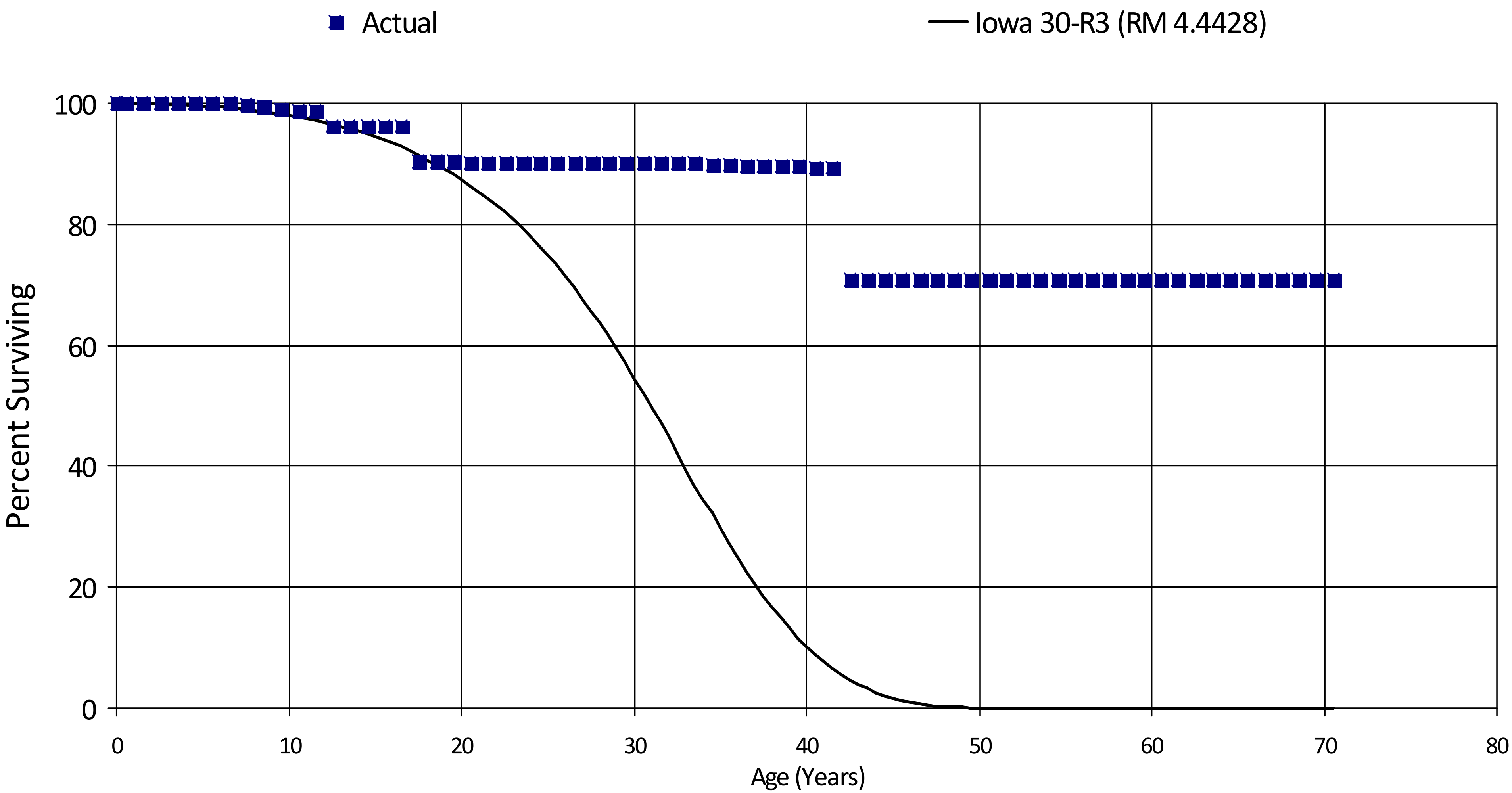
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,680	0	0.00000	1.00000	100.00
0.5	1,680	0	0.00000	1.00000	100.00
1.5	1,680	0	0.00000	1.00000	100.00
2.5	1,680	0	0.00000	1.00000	100.00
3.5	1,680	0	0.00000	1.00000	100.00
4.5	1,680	0	0.00000	1.00000	100.00
5.5	1,680	0	0.00000	1.00000	100.00
6.5	1,680	0	0.00000	1.00000	100.00
7.5	1,680	0	0.00000	1.00000	100.00
8.5	1,680	0	0.00000	1.00000	100.00
9.5	1,680	0	0.00000	1.00000	100.00
10.5	1,680	0	0.00000	1.00000	100.00
11.5	1,680	0	0.00000	1.00000	100.00
12.5	1,680	0	0.00000	1.00000	100.00
13.5	1,680	0	0.00000	1.00000	100.00
14.5	1,680	0	0.00000	1.00000	100.00
15.5	1,680	0	0.00000	1.00000	100.00
16.5	1,680	0	0.00000	1.00000	100.00
17.5	1,680	0	0.00000	1.00000	100.00
18.5	1,680	0	0.00000	1.00000	100.00
19.5	1,680	0	0.00000	1.00000	100.00
20.5	1,680	0	0.00000	1.00000	100.00
21.5	1,680	0	0.00000	1.00000	100.00
22.5	1,680	0	0.00000	1.00000	100.00
23.5	1,680	0	0.00000	1.00000	100.00
24.5	1,680	0	0.00000	1.00000	100.00
	Totals:	0			

MDU Gas

Account 387.20 - Distribution Plant - Other Distribution Equipment

Placement Band - 1950 - 2021   Experience Band - 1996 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 387.20 - Distribution Plant - Other Distribution Equipment

Placement Band - 1950 - 2021   Experience Band - 1996 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,860,775	0	0.00000	1.00000	100.00
0.5	753,053	0	0.00000	1.00000	100.00
1.5	753,053	0	0.00000	1.00000	100.00
2.5	753,053	782	0.00104	0.99896	100.00
3.5	752,270	0	0.00000	1.00000	99.90
4.5	751,571	0	0.00000	1.00000	99.90
5.5	690,091	0	0.00000	1.00000	99.90
6.5	611,632	1,504	0.00246	0.99754	99.90
7.5	610,127	921	0.00151	0.99849	99.65
8.5	609,207	3,481	0.00571	0.99429	99.50
9.5	605,726	950	0.00157	0.99843	98.93
10.5	604,776	0	0.00000	1.00000	98.77
11.5	604,776	16,214	0.02681	0.97319	98.77
12.5	588,562	0	0.00000	1.00000	96.12
13.5	588,562	0	0.00000	1.00000	96.12
14.5	588,562	0	0.00000	1.00000	96.12
15.5	586,813	0	0.00000	1.00000	96.12
16.5	576,911	35,061	0.06077	0.93923	96.12
17.5	541,850	0	0.00000	1.00000	90.28
18.5	541,850	0	0.00000	1.00000	90.28
19.5	540,434	1,681	0.00311	0.99689	90.28
20.5	538,754	0	0.00000	1.00000	90.00
21.5	531,299	0	0.00000	1.00000	90.00
22.5	531,299	0	0.00000	1.00000	90.00
23.5	526,348	0	0.00000	1.00000	90.00
24.5	488,036	0	0.00000	1.00000	90.00
25.5	436,734	0	0.00000	1.00000	90.00
26.5	420,697	0	0.00000	1.00000	90.00

27.5	387,017	0	0.00000	1.00000	90.00
28.5	378,689	0	0.00000	1.00000	90.00
29.5	370,413	0	0.00000	1.00000	90.00
30.5	367,395	0	0.00000	1.00000	90.00
31.5	353,707	0	0.00000	1.00000	90.00
32.5	344,560	0	0.00000	1.00000	90.00
33.5	333,038	419	0.00126	0.99874	90.00
34.5	330,157	183	0.00055	0.99945	89.89
35.5	258,629	360	0.00139	0.99861	89.84
36.5	206,502	0	0.00000	1.00000	89.72
37.5	163,701	0	0.00000	1.00000	89.72
38.5	129,358	0	0.00000	1.00000	89.72
39.5	104,959	447	0.00426	0.99574	89.72
40.5	86,007	0	0.00000	1.00000	89.34
41.5	64,527	13,410	0.20782	0.79218	89.34
42.5	39,848	0	0.00000	1.00000	70.77
43.5	39,654	0	0.00000	1.00000	70.77
44.5	39,654	0	0.00000	1.00000	70.77
45.5	39,654	0	0.00000	1.00000	70.77
46.5	39,654	0	0.00000	1.00000	70.77
47.5	52,934	0	0.00000	1.00000	70.77
48.5	52,934	0	0.00000	1.00000	70.77
49.5	52,934	0	0.00000	1.00000	70.77
50.5	52,851	0	0.00000	1.00000	70.77
51.5	50,989	0	0.00000	1.00000	70.77
52.5	50,783	0	0.00000	1.00000	70.77
53.5	50,308	0	0.00000	1.00000	70.77
54.5	48,936	0	0.00000	1.00000	70.77
55.5	48,581	0	0.00000	1.00000	70.77
56.5	46,247	0	0.00000	1.00000	70.77
57.5	44,845	0	0.00000	1.00000	70.77

MDU Gas

Account 387.20 - Distribution Plant - Other Distribution Equipment

Placement Band - 1950 - 2021 Experience Band - 1996 - 2021

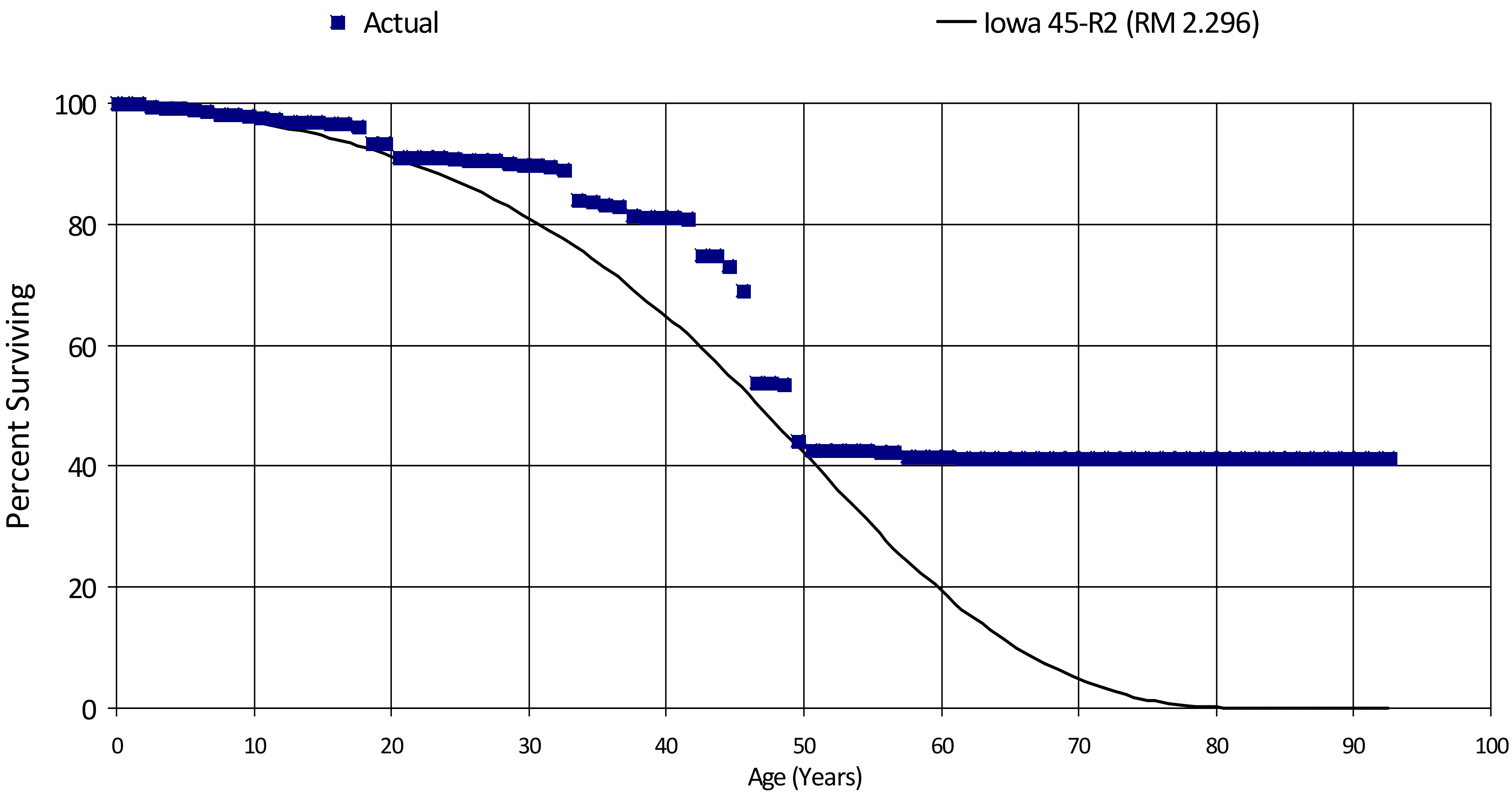
58.5	38,260	0	0.00000	1.00000	70.77
59.5	36,627	0	0.00000	1.00000	70.77
60.5	35,769	0	0.00000	1.00000	70.77
61.5	28,816	0	0.00000	1.00000	70.77
62.5	25,089	0	0.00000	1.00000	70.77
63.5	21,654	0	0.00000	1.00000	70.77
64.5	21,654	0	0.00000	1.00000	70.77
65.5	20,828	0	0.00000	1.00000	70.77
66.5	15,801	0	0.00000	1.00000	70.77
67.5	15,801	0	0.00000	1.00000	70.77
68.5	15,515	0	0.00000	1.00000	70.77
69.5	11,679	0	0.00000	1.00000	70.77
70.5	6,095	0	0.00000	1.00000	70.77
	Totals:	75,413			

MDU Gas

Account 390.00 - General Plant - Structures & Improvements

Placement Band - 1928 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 390.00 - General Plant - Structures & Improvements

Placement Band - 1928 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	17,487,888	0	0.00000	1.00000	100.00
0.5	17,470,203	2,754	0.00016	0.99984	100.00
1.5	16,040,711	87,479	0.00545	0.99455	99.98
2.5	15,732,429	32,334	0.00206	0.99794	99.44
3.5	14,658,034	7,754	0.00053	0.99947	99.24
4.5	14,427,578	46,218	0.00320	0.99680	99.19
5.5	14,356,321	10,955	0.00076	0.99924	98.87
6.5	14,256,458	64,464	0.00452	0.99548	98.79
7.5	14,143,845	16,305	0.00115	0.99885	98.34
8.5	13,774,709	24,787	0.00180	0.99820	98.23
9.5	13,533,476	62,342	0.00461	0.99539	98.05
10.5	13,461,551	31,687	0.00235	0.99765	97.60
11.5	12,216,754	58,435	0.00478	0.99522	97.37
12.5	10,696,910	7,990	0.00075	0.99925	96.90
13.5	10,526,894	0	0.00000	1.00000	96.83
14.5	6,288,537	1,626	0.00026	0.99974	96.83
15.5	6,270,272	11,061	0.00176	0.99824	96.80
16.5	6,220,031	29,240	0.00470	0.99530	96.63
17.5	6,187,583	182,300	0.02946	0.97054	96.18
18.5	6,005,284	2,413	0.00040	0.99960	93.35
19.5	2,118,611	51,261	0.02420	0.97580	93.31
20.5	1,943,397	0	0.00000	1.00000	91.05
21.5	1,809,782	0	0.00000	1.00000	91.05
22.5	1,798,971	0	0.00000	1.00000	91.05
23.5	1,797,088	5,025	0.00280	0.99720	91.05
24.5	1,792,062	3,102	0.00173	0.99827	90.80
25.5	1,788,960	2,373	0.00133	0.99867	90.64
26.5	2,309,954	0	0.00000	1.00000	90.52

MDU Gas

Account 390.00 - General Plant - Structures & Improvements

Placement Band - 1928 - 2021   Experience Band - 1995 - 2021

27.5	2,279,171	8,368	0.00367	0.99633	90.52
28.5	2,159,563	8,647	0.00400	0.99600	90.19
29.5	2,150,229	0	0.00000	1.00000	89.83
30.5	2,113,837	3,000	0.00142	0.99858	89.83
31.5	2,106,825	16,636	0.00790	0.99210	89.70
32.5	2,075,138	113,842	0.05486	0.94514	88.99
33.5	1,937,582	10,258	0.00529	0.99471	84.11
34.5	1,902,965	10,100	0.00531	0.99469	83.67
35.5	1,781,507	2,477	0.00139	0.99861	83.23
36.5	1,803,040	37,061	0.02055	0.97945	83.11
37.5	1,742,916	2,257	0.00129	0.99871	81.40
38.5	1,714,683	1,528	0.00089	0.99911	81.29
39.5	1,702,107	500	0.00029	0.99971	81.22
40.5	1,694,094	2,533	0.00150	0.99850	81.20
41.5	1,662,257	128,072	0.07705	0.92295	81.08
42.5	1,531,797	0	0.00000	1.00000	74.83
43.5	1,492,044	32,012	0.02146	0.97854	74.83
44.5	1,456,713	81,666	0.05606	0.94394	73.22
45.5	1,361,595	300,143	0.22043	0.77957	69.12
46.5	1,056,701	608	0.00058	0.99942	53.88
47.5	1,040,816	3,191	0.00307	0.99693	53.85
48.5	1,011,792	181,290	0.17918	0.82082	53.68
49.5	651,683	22,021	0.03379	0.96621	44.06
50.5	628,542	0	0.00000	1.00000	42.57
51.5	583,055	0	0.00000	1.00000	42.57
52.5	577,130	0	0.00000	1.00000	42.57
53.5	574,759	0	0.00000	1.00000	42.57
54.5	568,156	925	0.00163	0.99837	42.57
55.5	529,335	0	0.00000	1.00000	42.50
56.5	479,465	10,077	0.02102	0.97898	42.50
57.5	459,451	0	0.00000	1.00000	41.61

MDU Gas

Account 390.00 - General Plant - Structures & Improvements

Placement Band - 1928 - 2021   Experience Band - 1995 - 2021

58.5	446,666	0	0.00000	1.00000	41.61
59.5	444,052	1,138	0.00256	0.99744	41.61
60.5	437,046	594	0.00136	0.99864	41.50
61.5	423,896	0	0.00000	1.00000	41.44
62.5	422,474	0	0.00000	1.00000	41.44
63.5	421,200	0	0.00000	1.00000	41.44
64.5	418,264	0	0.00000	1.00000	41.44
65.5	331,553	0	0.00000	1.00000	41.44
66.5	263,844	0	0.00000	1.00000	41.44
67.5	260,693	103	0.00040	0.99960	41.44
68.5	240,481	0	0.00000	1.00000	41.42
69.5	232,153	0	0.00000	1.00000	41.42
70.5	227,923	0	0.00000	1.00000	41.42
71.5	219,105	0	0.00000	1.00000	41.42
72.5	215,471	0	0.00000	1.00000	41.42
73.5	200,410	0	0.00000	1.00000	41.42
74.5	185,350	0	0.00000	1.00000	41.42
75.5	170,290	0	0.00000	1.00000	41.42
76.5	170,290	0	0.00000	1.00000	41.42
77.5	169,545	0	0.00000	1.00000	41.42
78.5	169,545	0	0.00000	1.00000	41.42
79.5	169,545	0	0.00000	1.00000	41.42
80.5	169,545	0	0.00000	1.00000	41.42
81.5	154,485	0	0.00000	1.00000	41.42
82.5	139,792	0	0.00000	1.00000	41.42
83.5	125,457	0	0.00000	1.00000	41.42
84.5	111,472	0	0.00000	1.00000	41.42
85.5	97,828	0	0.00000	1.00000	41.42
86.5	84,517	0	0.00000	1.00000	41.42
87.5	71,531	0	0.00000	1.00000	41.42
88.5	58,861	0	0.00000	1.00000	41.42

MDU Gas

Account 390.00 - General Plant - Structures & Improvements

Placement Band - 1928 - 2021   Experience Band - 1995 - 2021

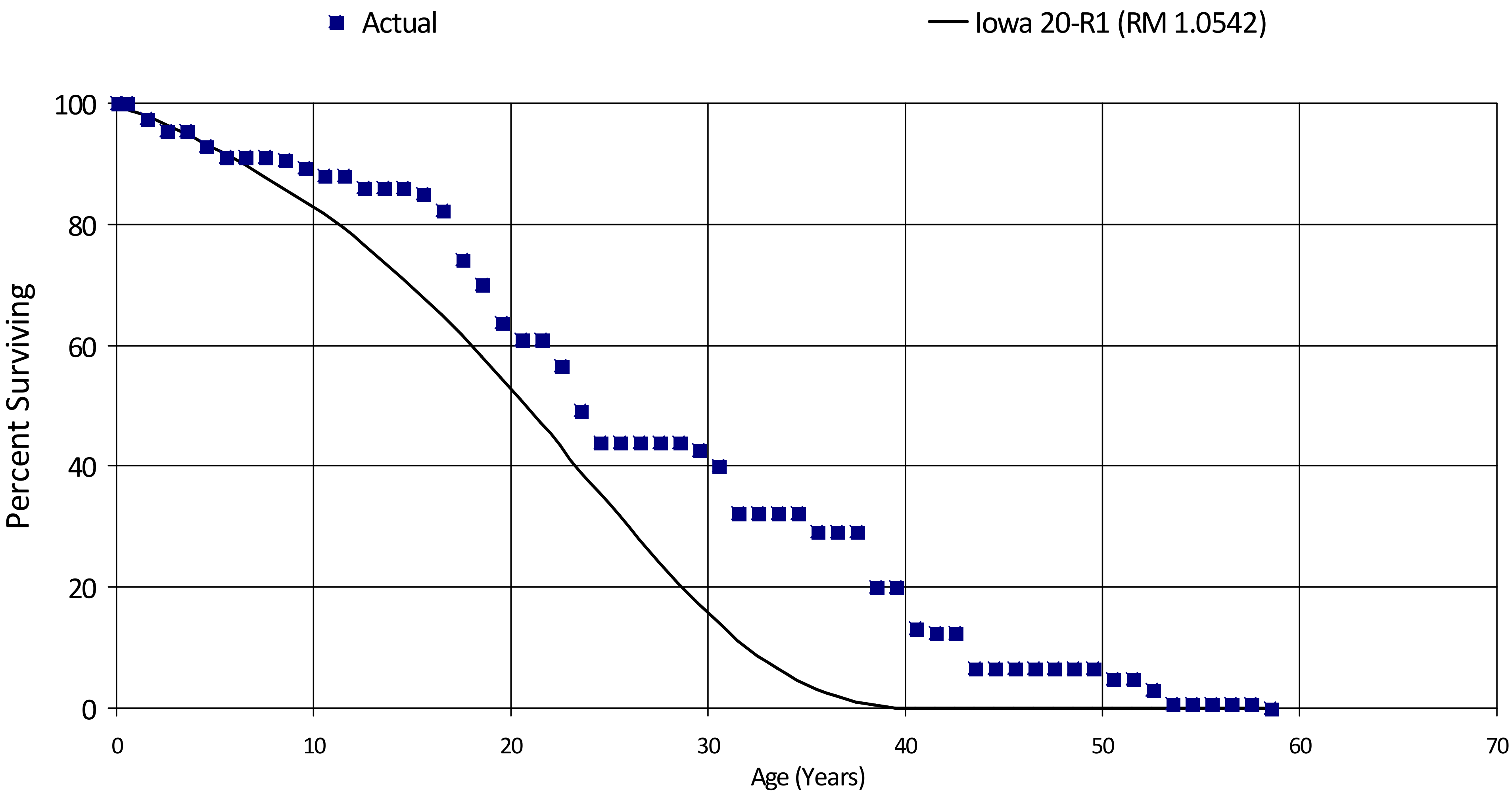
89.5	46,501	0	0.00000	1.00000	41.42
90.5	34,441	0	0.00000	1.00000	41.42
91.5	22,676	0	0.00000	1.00000	41.42
92.5	11,198	0	0.00000	1.00000	41.42
	Totals:	1,720,952			

MDU Gas

Account 392.10 - General Plant - Transportation Equipment - Trailers

Placement Band - 1952 - 2021   Experience Band - 2000 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 392.10 - General Plant - Transportation Equipment - Trailers

Placement Band - 1952 - 2021   Experience Band - 2000 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	620,212	0	0.00000	1.00000	100.00
0.5	620,212	15,197	0.02450	0.97550	100.00
1.5	605,015	13,431	0.02220	0.97780	97.55
2.5	591,585	0	0.00000	1.00000	95.38
3.5	561,788	15,274	0.02719	0.97281	95.38
4.5	546,515	9,844	0.01801	0.98199	92.79
5.5	536,670	0	0.00000	1.00000	91.12
6.5	536,670	0	0.00000	1.00000	91.12
7.5	536,670	3,012	0.00561	0.99439	91.12
8.5	533,659	7,814	0.01464	0.98536	90.61
9.5	499,258	7,244	0.01451	0.98549	89.28
10.5	425,912	0	0.00000	1.00000	87.98
11.5	380,779	8,282	0.02175	0.97825	87.98
12.5	372,497	0	0.00000	1.00000	86.07
13.5	318,714	0	0.00000	1.00000	86.07
14.5	243,289	3,167	0.01302	0.98698	86.07
15.5	240,122	8,012	0.03337	0.96663	84.95
16.5	192,339	18,597	0.09669	0.90331	82.12
17.5	152,614	8,695	0.05697	0.94303	74.18
18.5	116,261	10,486	0.09019	0.90981	69.95
19.5	74,301	3,329	0.04480	0.95520	63.64
20.5	70,973	0	0.00000	1.00000	60.79
21.5	70,973	4,975	0.07010	0.92990	60.79
22.5	65,998	8,633	0.13081	0.86919	56.53
23.5	43,919	4,593	0.10458	0.89542	49.14
24.5	34,038	0	0.00000	1.00000	44.00
25.5	34,038	0	0.00000	1.00000	44.00
26.5	28,740	0	0.00000	1.00000	44.00

MDU Gas

Account 392.10 - General Plant - Transportation Equipment - Trailers

Placement Band - 1952 - 2021   Experience Band - 2000 - 2021

27.5	28,740	0	0.00000	1.00000	44.00
28.5	28,740	827	0.02878	0.97122	44.00
29.5	27,913	1,788	0.06406	0.93594	42.73
30.5	17,765	3,492	0.19657	0.80343	39.99
31.5	14,272	0	0.00000	1.00000	32.13
32.5	14,272	0	0.00000	1.00000	32.13
33.5	13,353	0	0.00000	1.00000	32.13
34.5	13,353	1,269	0.09504	0.90496	32.13
35.5	12,083	0	0.00000	1.00000	29.08
36.5	12,083	0	0.00000	1.00000	29.08
37.5	12,083	3,740	0.30951	0.69049	29.08
38.5	8,343	0	0.00000	1.00000	20.08
39.5	8,343	2,861	0.34291	0.65709	20.08
40.5	5,483	310	0.05654	0.94346	13.19
41.5	5,173	0	0.00000	1.00000	12.44
42.5	5,173	2,402	0.46437	0.53563	12.44
43.5	2,771	0	0.00000	1.00000	6.66
44.5	2,771	0	0.00000	1.00000	6.66
45.5	2,771	0	0.00000	1.00000	6.66
46.5	2,771	0	0.00000	1.00000	6.66
47.5	2,771	0	0.00000	1.00000	6.66
48.5	2,771	0	0.00000	1.00000	6.66
49.5	2,771	771	0.27825	0.72175	6.66
50.5	1,999	0	0.00000	1.00000	4.81
51.5	1,999	749	0.37460	0.62540	4.81
52.5	1,250	956	0.76482	0.23518	3.01
53.5	294	0	0.00000	1.00000	0.71
54.5	294	0	0.00000	1.00000	0.71
55.5	294	0	0.00000	1.00000	0.71
56.5	294	0	0.00000	1.00000	0.71
57.5	294	294	1.00150	-0.00150	0.71

MDU Gas

Account 392.10 - General Plant - Transportation Equipment - Trailers

Placement Band - 1952 - 2021   Experience Band - 2000 - 2021

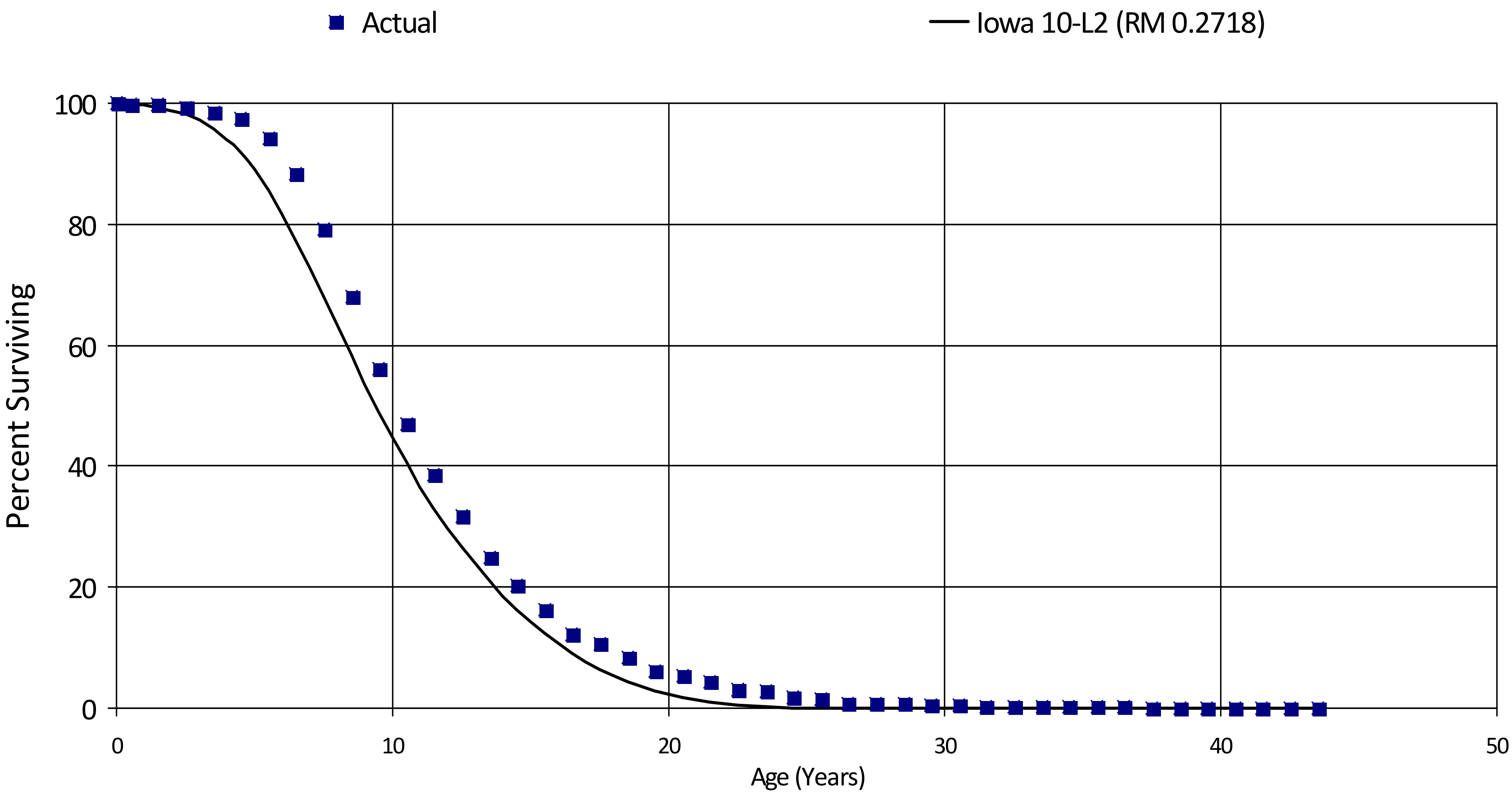
58.5	0	0	0.00000	0.00000	0.00
	Totals:	170,044			

MDU Gas

Account 392.20 - General Plant - Transportation Equipment

Placement Band - 1953 - 2021   Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 392.20 - General Plant - Transportation Equipment

Placement Band - 1953 - 2021 Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	29,798,980	66,241	0.00222	0.99778	100.00
0.5	28,690,259	46,905	0.00163	0.99837	99.78
1.5	26,953,780	83,728	0.00311	0.99689	99.62
2.5	25,049,217	179,981	0.00719	0.99281	99.31
3.5	24,294,158	255,874	0.01053	0.98947	98.60
4.5	22,165,228	768,953	0.03469	0.96531	97.56
5.5	19,851,441	1,247,981	0.06287	0.93713	94.18
6.5	16,847,888	1,714,369	0.10176	0.89824	88.26
7.5	14,617,855	2,089,504	0.14294	0.85706	79.28
8.5	12,222,590	2,114,402	0.17299	0.82701	67.95
9.5	9,927,869	1,642,587	0.16545	0.83455	56.20
10.5	7,910,689	1,415,915	0.17899	0.82101	46.90
11.5	6,213,621	1,099,387	0.17693	0.82307	38.51
12.5	4,974,605	1,075,494	0.21620	0.78380	31.70
13.5	3,798,147	682,709	0.17975	0.82025	24.85
14.5	3,064,666	632,155	0.20627	0.79373	20.38
15.5	2,405,840	590,403	0.24540	0.75460	16.18
16.5	1,724,859	220,327	0.12774	0.87226	12.21
17.5	1,277,243	280,236	0.21941	0.78059	10.65
18.5	873,160	223,756	0.25626	0.74374	8.31
19.5	589,281	75,882	0.12877	0.87123	6.18
20.5	490,531	102,090	0.20812	0.79188	5.38
21.5	372,045	99,657	0.26786	0.73214	4.26
22.5	272,389	32,045	0.11764	0.88236	3.12
23.5	240,344	80,953	0.33682	0.66318	2.75
24.5	159,390	21,071	0.13220	0.86780	1.82
25.5	137,242	60,469	0.44060	0.55940	1.58
26.5	46,373	9,080	0.19580	0.80420	0.88

MDU Gas

Account 392.20 - General Plant - Transportation Equipment

Placement Band - 1953 - 2021 Experience Band - 1995 - 2021

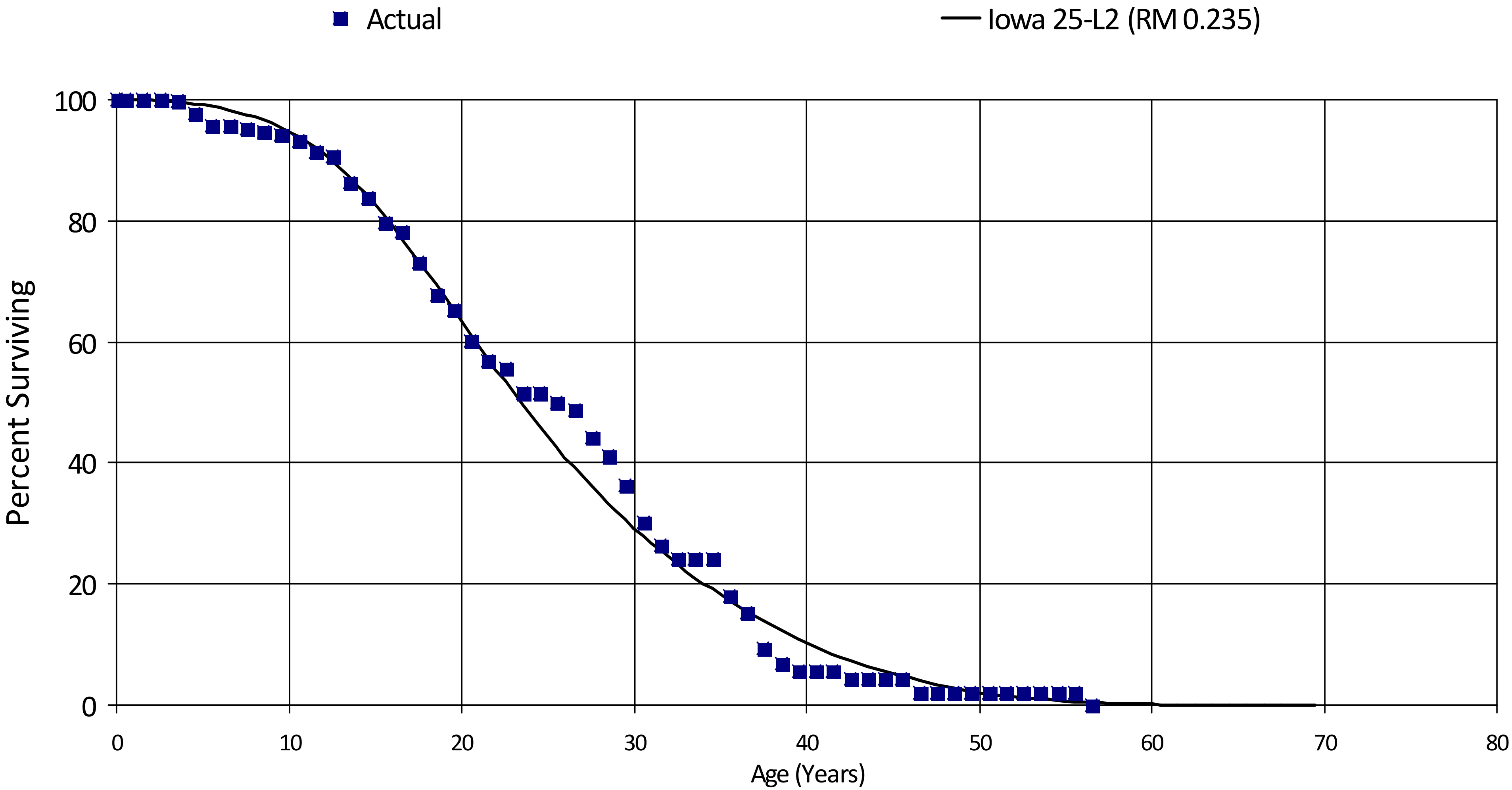
27.5	30,627	494	0.01613	0.98387	0.71
28.5	30,133	10,864	0.36054	0.63946	0.70
29.5	19,269	710	0.03685	0.96315	0.45
30.5	18,559	8,618	0.46436	0.53564	0.43
31.5	9,941	0	0.00000	1.00000	0.23
32.5	9,941	0	0.00000	1.00000	0.23
33.5	9,941	3,052	0.30701	0.69299	0.23
34.5	6,889	0	0.00000	1.00000	0.16
35.5	6,889	0	0.00000	1.00000	0.16
36.5	6,889	5,174	0.75100	0.24900	0.16
37.5	1,715	0	0.00000	1.00000	0.04
38.5	1,715	160	0.09329	0.90671	0.04
39.5	1,555	0	0.00000	1.00000	0.04
40.5	1,555	498	0.32021	0.67979	0.04
41.5	1,057	0	0.00000	1.00000	0.03
42.5	1,057	1,057	0.99958	0.00042	0.03
43.5	0	0	0.00000	0.00000	0.00
	Totals:	16,942,781			

MDU Gas

Account 396.10 - General Plant - Trailers - Work Equipment

Placement Band - 1953 - 2021 Experience Band - 1997 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 396.10 - General Plant - Trailers - Work Equipment

Placement Band - 1953 - 2021   Experience Band - 1997 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,622,065	0	0.00000	1.00000	100.00
0.5	1,568,930	0	0.00000	1.00000	100.00
1.5	1,427,636	0	0.00000	1.00000	100.00
2.5	1,369,017	4,497	0.00328	0.99672	100.00
3.5	1,221,233	24,079	0.01972	0.98028	99.67
4.5	1,128,595	22,602	0.02003	0.97997	97.70
5.5	876,758	0	0.00000	1.00000	95.74
6.5	856,055	5,064	0.00592	0.99408	95.74
7.5	694,572	3,539	0.00510	0.99490	95.17
8.5	622,954	4,000	0.00642	0.99358	94.68
9.5	584,047	6,462	0.01106	0.98894	94.07
10.5	522,222	8,873	0.01699	0.98301	93.03
11.5	482,306	3,829	0.00794	0.99206	91.45
12.5	478,477	23,746	0.04963	0.95037	90.72
13.5	434,840	12,835	0.02952	0.97048	86.22
14.5	400,559	19,102	0.04769	0.95231	83.67
15.5	352,779	6,269	0.01777	0.98223	79.68
16.5	337,145	21,918	0.06501	0.93499	78.26
17.5	287,345	21,546	0.07498	0.92502	73.17
18.5	260,735	9,467	0.03631	0.96369	67.68
19.5	233,598	18,117	0.07756	0.92244	65.22
20.5	201,373	11,191	0.05557	0.94443	60.16
21.5	190,182	4,461	0.02346	0.97654	56.82
22.5	128,667	9,108	0.07079	0.92921	55.49
23.5	112,344	138	0.00123	0.99877	51.56
24.5	108,672	3,099	0.02852	0.97148	51.50
25.5	105,573	2,672	0.02531	0.97469	50.03
26.5	102,902	9,530	0.09261	0.90739	48.76

MDU Gas

Account 396.10 - General Plant - Trailers - Work Equipment

Placement Band - 1953 - 2021 Experience Band - 1997 - 2021

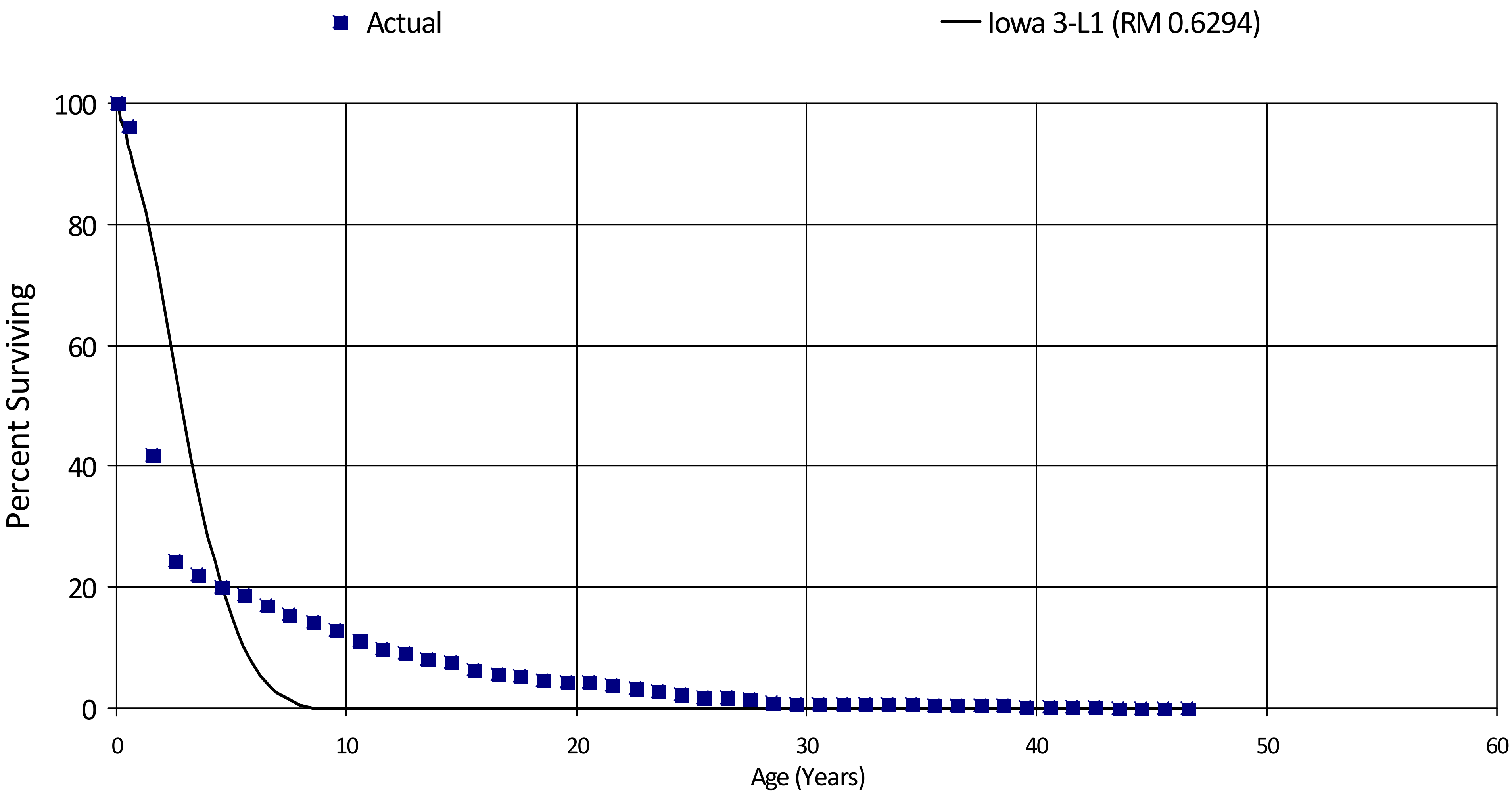
27.5	64,256	4,702	0.07318	0.92682	44.24
28.5	56,764	6,430	0.11328	0.88672	41.00
29.5	50,335	8,653	0.17191	0.82809	36.36
30.5	41,681	5,105	0.12248	0.87752	30.11
31.5	36,576	3,308	0.09044	0.90956	26.42
32.5	33,268	0	0.00000	1.00000	24.03
33.5	33,268	0	0.00000	1.00000	24.03
34.5	33,268	8,254	0.24810	0.75190	24.03
35.5	25,014	3,852	0.15399	0.84601	18.07
36.5	21,163	8,285	0.39149	0.60851	15.29
37.5	11,192	3,095	0.27653	0.72347	9.30
38.5	8,097	1,520	0.18772	0.81228	6.73
39.5	6,577	0	0.00000	1.00000	5.47
40.5	6,577	0	0.00000	1.00000	5.47
41.5	6,577	1,493	0.22701	0.77299	5.47
42.5	5,083	0	0.00000	1.00000	4.23
43.5	5,083	0	0.00000	1.00000	4.23
44.5	5,083	0	0.00000	1.00000	4.23
45.5	5,083	2,593	0.51009	0.48991	4.23
46.5	2,491	0	0.00000	1.00000	2.07
47.5	2,491	0	0.00000	1.00000	2.07
48.5	2,491	0	0.00000	1.00000	2.07
49.5	2,491	0	0.00000	1.00000	2.07
50.5	2,491	0	0.00000	1.00000	2.07
51.5	2,491	0	0.00000	1.00000	2.07
52.5	2,491	0	0.00000	1.00000	2.07
53.5	2,491	0	0.00000	1.00000	2.07
54.5	2,491	0	0.00000	1.00000	2.07
55.5	2,491	2,491	1.00006	-0.00006	2.07
56.5	0	0	0.00000	0.00000	0.00
	Totals:	315,925			

MDU Gas

Account 396.20 - General Plant - Power Operated Equipment

Placement Band - 1953 - 2021 Experience Band - 1995 - 2021

Actual and Smooth Survivor Curves



MDU Gas

Account 396.20 - General Plant - Power Operated Equipment

Placement Band - 1953 - 2021   Experience Band - 1995 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	64,675,834	2,543,199	0.03932	0.96068	100.00
0.5	58,642,873	33,142,793	0.56516	0.43484	96.07
1.5	24,914,766	10,339,982	0.41501	0.58499	41.78
2.5	14,116,952	1,349,769	0.09561	0.90439	24.44
3.5	12,186,392	1,062,198	0.08716	0.91284	22.10
4.5	10,641,556	717,271	0.06740	0.93260	20.17
5.5	9,031,281	847,303	0.09382	0.90618	18.81
6.5	7,904,243	751,130	0.09503	0.90497	17.05
7.5	6,716,302	582,368	0.08671	0.91329	15.43
8.5	5,960,900	526,472	0.08832	0.91168	14.09
9.5	5,084,631	679,818	0.13370	0.86630	12.85
10.5	4,176,501	418,747	0.10026	0.89974	11.13
11.5	3,679,257	364,744	0.09914	0.90086	10.01
12.5	3,314,512	317,151	0.09569	0.90431	9.02
13.5	2,878,761	234,234	0.08137	0.91863	8.16
14.5	2,400,382	348,908	0.14536	0.85464	7.50
15.5	1,932,795	270,011	0.13970	0.86030	6.41
16.5	1,468,970	71,444	0.04864	0.95136	5.51
17.5	1,352,698	156,322	0.11556	0.88444	5.24
18.5	1,066,010	66,599	0.06248	0.93752	4.63
19.5	914,634	18,569	0.02030	0.97970	4.34
20.5	896,065	71,652	0.07996	0.92004	4.25
21.5	758,045	118,098	0.15579	0.84421	3.91
22.5	639,193	90,827	0.14210	0.85790	3.30
23.5	548,366	101,408	0.18493	0.81507	2.83
24.5	446,958	80,486	0.18008	0.81992	2.31
25.5	366,471	37,916	0.10346	0.89654	1.89
26.5	325,859	34,710	0.10652	0.89348	1.69

MDU Gas

Account 396.20 - General Plant - Power Operated Equipment

Placement Band - 1953 - 2021 Experience Band - 1995 - 2021

27.5	291,149	107,895	0.37058	0.62942	1.51
28.5	183,254	27,055	0.14764	0.85236	0.95
29.5	156,199	2,498	0.01599	0.98401	0.81
30.5	153,701	15,680	0.10202	0.89798	0.80
31.5	138,021	0	0.00000	1.00000	0.72
32.5	138,021	0	0.00000	1.00000	0.72
33.5	138,021	0	0.00000	1.00000	0.72
34.5	138,021	20,288	0.14699	0.85301	0.72
35.5	117,733	10,913	0.09269	0.90731	0.61
36.5	106,820	1,727	0.01617	0.98383	0.55
37.5	105,093	19,393	0.18453	0.81547	0.54
38.5	85,700	15,903	0.18557	0.81443	0.44
39.5	69,797	0	0.00000	1.00000	0.36
40.5	69,797	8,672	0.12425	0.87575	0.36
41.5	61,124	20,648	0.33780	0.66220	0.32
42.5	40,477	18,271	0.45139	0.54861	0.21
43.5	22,206	3,191	0.14370	0.85630	0.12
44.5	19,015	0	0.00000	1.00000	0.10
45.5	19,015	19,015	0.99999	0.00001	0.10
46.5	0	0	0.00000	0.00000	0.00
	Totals:	55,635,278			

SECTION 7

7 NET SALVAGE

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 376 - DISTRIBUTION PLANT - MAINS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	81,561	22,342	27	(0)	(0)	(22,342)	-27					-22,342	-27
1996	309,280	83,392	27	(767)	(0)	(82,624)	-27					-52,483	-27
1997	187,244	-	0	(56,675)	(30)	56,675	30	-16,097	-8			-16,097	-8
1998	196,625	76,362	39	(806)	(0)	(75,556)	-38	-33,835	-15			-30,962	-16
1999	186,253	82,439	44		0	(82,439)	-44	-33,773	-18	-41,257	-21	-41,257	-21
2000	158,498	61,044	39		0	(61,044)	-39	-73,013	-40	-48,998	-24	-44,555	-24
2001	171,124	74,110	43		0	(74,110)	-43	-72,531	-42	-47,295	-26	-48,777	-26
2002	118,947	70,046				(70,046)		-68,400	-46	-72,639	-44	-51,436	-29
2003	234,206	150,702	64		0	(150,702)	-64	-98,286	-56	-87,668	-50	-62,465	-34
2004	390,888	80,069	20		0	(80,069)	-20	-100,272	-40	-87,194	-41	-64,226	-32
2005	169,555	57,360	34		0	(57,360)	-34	-96,044	-36	-86,457	-40	-63,602	-32
2006	122,132	50,615	41	(805)	(1)	(49,810)	-41	-62,413	-27	-81,598	-39	-62,452	-32
2007	260,243	85,572	33	(230)	(0)	(85,342)	-33	-64,171	-35	-84,657	-36	-64,213	-32
2008	441,209	72,514	16	(155)	(0)	(72,359)	-16	-69,171	-25	-68,988	-25	-64,795	-30
2009	230,827	74,552	32	(2,250)	(1)	(72,302)	-31	-76,668	-25	-67,435	-28	-65,295	-30
2010	302,631	101,644	34		0	(101,644)	-34	-82,102	-25	-76,291	-28	-67,567	-30
2011	333,661	201,494	60		0	(201,494)	-60	-125,146	-43	-106,628	-34	-75,445	-33
2012	222,753	120,281	54		0	(120,281)	-54	-141,139	-49	-113,616	-37	-77,936	-34
2013	440,039	176,361	40		0	(176,361)	-40	-166,045	-50	-134,416	-44	-83,116	-35
2014	514,341	250,309	49		0	(250,309)	-49	-182,317	-46	-170,018	-47	-91,476	-36
2015	508,795	476,808	94		0	(476,808)	-94	-301,159	-62	-245,050	-61	-109,825	-41
2016	605,695	238,752	39	(189)	(0)	(238,562)	-39	-321,893	-59	-252,464	-55	-115,677	-41
2017	614,168	546,423	89		0	(546,423)	-89	-420,598	-73	-337,693	-63	-134,405	-45
2018	679,997	545,026	80	(12,152)	(2)	(532,874)	-78	-439,287	-69	-408,995	-70	-151,008	-48
2019	1,112,186	533,323	48		0	(533,323)	-48	-537,540	-67	-465,598	-66	-166,300	-48
2020	1,223,259	1,879,764	154		0	(1,879,764)	-154	-981,987	-98	-746,189	-88	-232,203	-62
2021	1,260,741	1,606,339	127		0	(1,606,339)	-127	-1,339,809	-112	-1,019,745	-104	-283,097	-69
TOTAL	**11,076,857**	**7,717,643**	**69.67**	**-74,030**	**(0.67)**	**-7,643,613**	**(69.01)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 378 - DISTRIBUTION PLANT - MEAS & REG STATION EQUIP - GENERAL
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	3,767	4,927	131	(4,785)	(127)	(142)						-142	-4
1996	22,620	10,141	45	(4,352)	(19)	(5,789)	-26					-2,966	-22
1997	17,785	8,057	45	(713)	(4)	(7,344)	-41	-4,425	-30			-4,425	-30
1998	16,659	8,754	53	(1,482)	(9)	(7,272)	-44	-6,802	-36			-5,137	-34
1999	3,764	749	20	0	0	(749)	-20	-5,122	-40	-4,259	-33	-4,259	-33
2000		6,839		(963)		(5,877)		-4,633	-68	-5,406	-44	-4,529	-42
2001	8,696	6,139	71	(2,154)	(25)	(3,986)	-46	-3,537	-85	-5,045	-54	-4,451	-43
2002	6,660	940	14	0	0	(940)	-14	-3,601	-70	-3,765	-53	-4,012	-40
2003	10,744	16,775	156	0	0	(16,775)	-156	-7,233	-83	-5,665	-95	-5,430	-54
2004	16,732	80,069	479		0	(80,069)	-479	-32,595	-286	-21,529	-251	-12,894	-120
2005	8,182	2,304	28		0	(2,304)	-28	-33,049	-278	-20,815	-204	-11,931	-114
2006	2,239		0		0	0	0	-27,458	-303	-20,018	-225	-11,931	-111
2007	22,626	913	4		0	(913)	-4	-1,073	-10	-20,012	-165	-11,013	-94
2008	17,733	850	5		0	(850)	-5	-588	-4	-16,827	-125	-10,232	-84
2009	21,935	1,147	5		0	(1,147)	-5	-970	-5	-1,043	-7	-9,583	-74
2010	9,162	10,177	111		0	(10,177)	-111	-4,058	-25	-2,618	-18	-9,622	-76
2011	3,332	(1,215)	(36)		0	1,215	36	-3,370	-29	-2,374	-16	-8,945	-74
2012	20,368		0		0	0	0	-2,987	-27	-2,192	-15	-8,945	-67
2013	20,366	10,761	53		0	(10,761)	-53	-3,182	-22	-4,174	-28	-9,052	-66
2014	17,711	12,015	68		0	(12,015)	-68	-7,592	-39	-6,347	-45	-9,216	-66
2015	5,755	4,268	74		0	(4,268)	-74	-9,015	-62	-5,166	-38	-8,956	-66
2016	(22)	3,912	(17,489)		0	(3,912)	17,489	-6,732	-86	-6,191	-48	-8,704	-68
2017	6,336	8,873	140		0	(8,873)	-140	-5,685	-141	-7,966	-79	-8,712	-70
2018	43,844	13,243	30		0	(13,243)	-30	-8,676	-52	-8,462	-57	-8,918	-64
2019	185,381	4,397	2		0	(4,397)	-2	-8,838	-11	-6,939	-14	-8,721	-41
2020	32,028	3,193	10		0	(3,193)	-10	-6,944	-8	-6,724	-13	-8,491	-39
2021	11,592	28,073	242		0	(28,073)	-242	-11,888	-16	-11,556	-21	-9,274	-43
TOTAL	**535,996**	**246,302**	**45.95**	**-14,449**	**(2.70)**	**-231,853**	**(43.26)**						

Montana-Dakota Utilities Co. - Gas Plant

ACCOUNT 379 - DISTRIBUTION PLANT - MEAS & REG STATION EQUIP - CITY GATE

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	1,429		0		0	0	0						0
1996				(375)		375						375	
1997	19,118	846	4	(3,723)	(19)	2,877	15	1,084	16			1,626	
1998	2,594		0		0	0	0	1,084	14			1,626	
1999	1,744	280	16		0	(280)	-16	991	12	594	12	991	
2000						0		991	12	594	12	991	12
2001						0		991	12	594	12	991	12
2002						0		0	0	594	12	991	12
2003	(4,387)		0		0	0	0	0	0	594	15	991	15
2004	1,470		0		0	0	0	0	0	0	0	991	14
2005						0		0	0	0	0	991	14
2006						0		0	0	0	0	991	14
2007						0		0	0	0	0	991	14
2008	8,335		0		0	0		0	0	0	0	991	10
2009	23,768		0		0	0	0	0	0	0	0	991	5
2010						0		0	0	0	0	991	5
2011	15,454	1,500	10		0	(1,500)	-10	-500	-4	-300	-3	368	2
2012	2,466		0		0	0	0	-500	-8	-300	-3	368	2
2013	6279.98		0		0	0	0	-500	-6	-300	-3	368	2
2014	17,713		0		0	0	0	0	0	-300	-4	368	2
2015	7,312		0		0	0	0	0	0	-300	-3	368	1
2016	8,268		0		0	0	0	0	0	0	0	368	1
2017	9,848	197	2		0	(197)	-2	-66	-1	-39	0	255	1
2018	33,955	1,461	4	(12,152)	(36)	10,691	31	3,498	20	2,099	14	1,995	8
2019	24,638	6,728	27		0	(6,728)	-27	1,256	6	753	4	748	3
2020		9,804				(9,804)		-1,947	-10	-1,207	-8	-571	-3
2021	4,756		0		0	0	0	-5,511	-56	-1,207	-8	-571	-2
TOTAL	**184,761**	**20,815**	**11.27**	**-16,251**	**(8.80)**	**-4,565**	**(2.47)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 380 - DISTRIBUTION PLANT - SERVICES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	85,367	132,997	156	(239)	(0)	(132,758)	-156					-132,758	-156
1996	190,816	196,475	103	(489)	(0)	(195,985)	-103					-164,372	-119
1997	146,554	167,867	115	(274)	(0)	(167,593)	-114	-165,445	-117			-165,445	-117
1998	153,275	232,839	152	(166)	(0)	(232,674)	-152	-198,751	-122			-182,253	-127
1999	130,041	205,973	158		0	(205,973)	-158	-202,080	-141	-186,997	-132	-186,997	-132
2000	134,394	200,261	149		0	(200,261)	-149	-212,969	-153	-200,497	-133	-189,207	-135
2001	123,810	203,229	164	(31)	(0)	(203,197)	-164	-203,143	-157	-201,939	-147	-191,206	-139
2002	95,020	198,438	209		0	(198,438)	-209	-200,632	-170	-208,108	-163	-192,110	-145
2003	167,545	269,303	161	(2,266)	(1)	(267,037)	-159	-222,891	-173	-214,981	-165	-200,435	-147
2004	184,932	371,150	201		0	(371,150)	-201	-278,875	-187	-248,017	-176	-217,507	-154
2005	88,648	257,937	291	(79)	(0)	(257,858)	-291	-298,682	-203	-259,536	-197	-221,175	-162
2006	109,444	265,998	243	(275)	(0)	(265,723)	-243	-298,244	-234	-272,041	-211	-224,887	-168
2007	173,206	367,376	212	(46)	(0)	(367,329)	-212	-296,970	-240	-305,820	-211	-235,844	-172
2008	112,618	322,738	287	(461)	(0)	(322,277)	-286	-318,443	-242	-316,868	-237	-242,018	-179
2009	110,259	345,193	313	(336)	(0)	(344,857)	-313	-344,821	-261	-311,609	-262	-248,874	-186
2010	166,698	422,812	254	(135)	(0)	(422,678)	-254	-363,271	-280	-344,573	-256	-259,737	-191
2011	186,877	358,576	192		0	(358,576)	-192	-375,370	-243	-363,143	-242	-265,551	-191
2012	173,141	398,268	230		0	(398,268)	-230	-393,174	-224	-369,331	-246	-272,924	-194
2013	243,711	394,504	162		0	(394,504)	-162	-383,782	-191	-383,776	-218	-279,323	-191
2014	286,281	388,263	136		0	(388,263)	-136	-393,678	-168	-392,458	-186	-284,770	-186
2015	277,245	502,378	181		0	(502,378)	-181	-428,381	-159	-408,398	-175	-295,132	-186
2016	410,494	390,968	95	(40,328)	(10)	(350,640)	-85	-413,760	-127	-406,810	-146	-297,655	-175
2017	274,864	1,190,919	433		0	(1,190,919)	-433	-681,313	-212	-565,341	-189	-336,493	-192
2018	503,851	558,306	111		0	(558,306)	-111	-699,955	-177	-598,101	-171	-345,735	-183
2019	412,144	969,944	235		0	(969,944)	-235	-906,390	-228	-714,438	-190	-370,703	-188
2020	1,267,662	1,139,364	90		0	(1,139,364)	-90	-889,205	-122	-841,835	-147	-400,267	-168
2021	696,703	1,119,123	161		0	(1,119,123)	-161	-1,076,144	-136	-995,531	-158	-426,892	-167
TOTAL	**6,905,600**	**11,571,198**	**167.56**	**-45,125**	**(0.65)**	**-11,526,073**	**(166.91)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 381 - DISTRIBUTION PLANT - METERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	260,859		0	(141)	(0)	141	0					141	0
1996	148,430		0	(8,203)	(6)	8,203	6					4,172	2
1997	163,998		0	(3,569)	(2)	3,569	2	3,971	2			3,971	2
1998	167,985		0	(395)	(0)	395	0	4,056	3			3,077	2
1999	105,588		0	(1,112)	(1)	1,112	1	1,692	1	2,684	2	2,684	2
2000	81,310		0	(12,514)	(15)	12,514	15	4,674	4	5,159	4	4,322	3
2001	417,487	92,372	22	(3,201)	(1)	(89,171)	-21	-25,182	-12	-14,316	-8	-9,034	-5
2002	1,907	78	4	(756)	(40)	678	36	-25,326	-15	-14,894	-10	-7,820	-5
2003	13,398	838	6	(10,850)	(81)	10,013	75	-26,160	-18	-12,971	-10	-5,838	-4
2004	29,662	6,515	22	(13,191)	(44)	6,676	23	5,789	39	-11,858	-11	-4,587	-3
2005	1,342,412	418,681	31	(35,501)	(3)	(383,180)	-29	-122,164	-26	-90,997	-25	-39,005	-16
2006	46,152	6,552	14	(29,808)	(65)	23,256	50	-117,749	-25	-68,511	-24	-33,816	-15
2007	569,985	24,276	4	(11,103)	(2)	(13,173)	-2	-124,366	-19	-71,282	-18	-32,228	-13
2008	53,911	118,829	220	(48,608)	(90)	(70,221)	-130	-20,046	-9	-87,328	-21	-34,942	-14
2009	2,454,871	651,948	27	(10,242)	(0)	(641,706)	-26	-241,700	-24	-217,005	-24	-75,393	-19
2010	218,193	34,716	16	(8,228)	(4)	(26,488)	-12	-246,138	-27	-145,666	-22	-72,336	-19
2011	439,009	167,032	38	(25,672)	(6)	(141,360)	-32	-269,851	-26	-178,590	-24	-76,397	-20
2012	482,546	60,816	13	(15,026)	(3)	(45,791)	-9	-71,213	-19	-185,113	-25	-74,696	-19
2013	280,825		0		0	0	0	-62,384	-16	-171,069	-22	-74,696	-18
2014	372,162	148,438	40	(27,111)	(7)	(121,327)	-33	-55,706	-15	-66,993	-19	-77,150	-19
2015	361,847	75,061	21	(9,617)	(3)	(65,444)	-18	-62,257	-18	-74,784	-19	-76,565	-19
2016	417,093	72,759	17	(3,234)	(1)	(69,525)	-17	-85,432	-22	-60,417	-16	-76,230	-19
2017	814,936	105,166	13	(3,145)	(0)	(102,021)	-13	-78,997	-15	-71,663	-16	-77,402	-18
2018	690,542	128,851	19	(35,316)	(5)	(93,535)	-14	-88,360	-14	-90,371	-17	-78,104	-18
2019	1,777,501	199,304	11	(1,963)	(0)	(197,342)	-11	-130,966	-12	-105,573	-13	-83,072	-17
2020	1,488,126	302,639	20	(2,365)	(0)	(300,274)	-20	-197,050	-15	-152,539	-15	-91,760	-17
2021	1,871,033	316,458	17	(3,944)	(0.21)	(312,515)	-17	-270,043	-16	-201,137	-15	-100,251	-17
TOTAL	**15,071,768**	**2,931,331**	**19.45**	**-324,816**	**(2.16)**	**-2,606,515**	**(17.29)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 383 - DISTRIBUTION PLANT - SERVICE REGULATORS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	38,395		0	(378)	(1)	378	1					378	1
1996	55,425	738	1	(10,699)	(19)	9,961	18						0
1997	16,406		0	(7,614)	(46)	7,614	46	5,984	16			5,984	16
1998	30,249	72	0	(9,527)	(31)	9,455	31	9,010	26			6,852	20
1999	887		0		0	0	0	5,690	36	5,482	19	6,852	19
2000	3,395		0		0	0	0	3,152	27	5,406	25	6,852	19
2001	22,146		0	(6,353)	(29)	6,353	29	2,118	24	4,684	32	6,752	20
2002	5,255		0	(717)	(14)	717	14	2,357	23	3,305	27	5,746	20
2003	11,656	745	6	(19,962)	(171)	19,217	165	8,762	67	5,257	61	7,671	29
2004	3,292		0	(2,287)	(69)	2,287	69	7,407	110	5,715	62	6,998	30
2005	(19)		0	(4,479)	23,661	4,479	-23,661	8,661	174	6,611	78	6,718	32
2006	1,838		0	(8,135)	(442)	8,135	442	4,967	292	6,967	158	6,860	36
2007	273		0	(5,844)	(2,139)	5,844	2,139	6,153	882	7,992	235	6,767	39
2008	7,276	745	10	(11,579)	(159)	10,834	149	8,271	264	6,316	249	7,106	43
2009	10,028	(8)	(0)	(4,731)	(47)	4,739	47	7,139	122	6,806	175	6,924	44
2010	20,139		0	(6,366)	(32)	6,366	32	7,313	59	7,184	91	6,884	43
2011	8,331	641	8	(12,448)	(149)	11,806	142	7,637	60	7,918	86	7,212	46
2012	18,197	760	4	(6,613)	(36)	5,853	32	8,009	51	7,920	62	7,127	45
2013	19,423		0		0	0	0	5,886	38	5,753	38	7,127	42
2014	27,584	6,211	23	(21,359)	(77)	15,147	55	7,000	32	7,835	42	7,599	43
2015	45,321	5,899	13	(293)	(1)	(5,605)	-12	3,181	10	5,440	23	6,866	36
2016	56,446	13,840	25	(1,624)	(3)	(12,216)	-22	-891	-2	636	2	5,861	28
2017	63,395	13,785	22	(1,298)	(2)	(12,487)	-20	-10,103	-18	-3,032	-7	4,944	21
2018	105,784	20,540	19	(2,225)	(2)	(18,315)	-17	-14,339	-19	-6,695	-11	3,836	14
2019	86,067	12,896	15	(1,488)	(2)	(11,408)	-13	-14,070	-17	-12,006	-17	3,143	11
2020	118,467	41,235	35		0	(41,235)	-35	-23,653	-23	-19,132	-22	1,214	4
2021	130,888	45,765	35	(702)	(0.54)	(45,063)	-34	-32,569	-29	-25,702	-25	-714	-2
TOTAL	**906,544**	**163,865**	**18.08**	**-146,720**	**(16.18)**	**-17,144**	**(1.89)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 385 DISTRIBUTION PLANT - INDUSTRIAL MEAS. & REG. STATION EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995						0							0
1996	521		0		0	0	0						0
1997	1778.43		0		0	0	0	0	0				0
1998	7894.41		0		0	0	0	0	0				0
1999	8,226		0		0	0	0	0	0	0	0		0
2000						0		0	0	0	0		0
2001	375		0		0	0	0	0	0	0	0		0
2002	561.38		0		0	0	0	0	0	0	0		0
2003	6,164		0		0	0	0	0	0	0	0		0
2004	464.54		0		0	0	0	0	0	0	0		0
2005	2526.6		0		0	0	0	0	0	0	0		0
2006						0		0	0	0	0		0
2007						0		0	0	0	0		0
2008						0		0	0	0	0		0
2009	24.58		0		0	0	0	0	0	0	0		0
2010						0		0	0	0	0		0
2011						0		0	0	0	0		0
2012						0		0	0	0	0		0
2013						0		0	0	0	0		0
2014						0		0	0	0	0		0
2015		(736)				736		245	0	147	0	736	3
2016	3,815	1,466	38		0	(1,466)	-38	-243	-19	-146	-19	-365	-2
2017	-3406.4	1,407	(41)		0	(1,407)	41	-712	-523	-427	-523	-712	-7
2018	285.57	3,689	1,292		0	(3,689)	-1,292	-2,187	-946	-1,165	-839	-1,456	-20
2019	34,766	3,661	11		0	(3,661)	-11	-2,919	-28	-1,897	-27	-1,897	-15
2020						0		-2,450	-21	-2,045	-29	-1,897	-15
2021	25,895	16,842	65		0	(16,842)	-65	-6,834	-34	-5,120	-44	-4,388	-29
TOTAL	**89,890**	**26,329**	**29.29**	**0**	**0.00**	**-26,329**	**(29.29)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 387.2- DISTRIBUTION PLANT - OTHER DISTRIBUTION EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1996	3,481.02												0
1997	962.88												0
1998								0	0				0
1999	2,659.56							0	0				0
2000								0	0	0	0		0
2001								0	0	0	0		0
2002								0	0	0	0		0
2003	1,945.37		0		0	0	0	0	0	0	0		0
2004						0		0	0	0	0		0
2005	16,213.95		0		0		0	0	0	0	0		0
2006								0	0	0	0		0
2007								0	0	0	0		0
2008								0	0	0	0		0
2009								0	0	0	0		0
2010								0	0	0	0		0
2011								0	0	0	0		0
2012								0	0	0	0		0
2013						0		0	0	0	0		0
2014						0		0	0	0	0		0
2015						0		0	0	0	0		0
2016	15,091	640	4		0	(640)	-4	-213	-4	-128	-4	-40	-2
2017						0		-213	-4	-128	-4	-40	-2
2018						0		-213	-4	-128	-4	-40	-2
2019						0		0	0	-128	-4	-40	-2
2020						0		0	0	-128	-4	-40	-2
2021	35,061	1,376	4		0	(1,376)	-4	-459	-4	-275	-4	-119	-3
TOTAL	**75,414**	**2,016**	**2.67**	**0**	**0.00**	**-2,016**	**(2.67)**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 390 - GENERAL PLANT - STRUCTURES & IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	109,500	934	1	(154,090)	(141)	153,156	140					153,156	140
1996	138,638	1,218	1	(196,098)	(141)	194,880	141					174,018	140
1997	9710.6	578	6		0	(578)	-6	115,819	135			115,819	135
1998	6,373	1,007	16		0	(1,007)	-16	64,432	125			86,613	131
1999	2036.72		0		0	0	0	-528	-9	69,290	130	86,613	130
2000						0		-336	-12	38,659	123	86,613	130
2001						0		0	0	-317	-9	86,613	130
2002	469,369	23,530	5	(325,000)	(69)	301,470	64	100,490	64	60,093	63	129,584	88
2003	9314		0		0	0	0	100,490	63	60,294	63	129,584	87
2004	3,228	125	4		0	(125)	-4	100,448	63	60,269	63	107,966	87
2005	6,951		0		0	0	0	-42	-1	60,269	62	107,966	86
2006	11,119		0		0	0	0	-42	-1	60,269	60	107,966	85
2007	17,472	2,002	11	(40,375)	(231)	38,373	220	12,791	108	7,650	80	98,024	88
2008	10,888		0	(7,171)	(66)	7,171	66	15,181	115	9,084	91	86,668	87
2009	47,664	12,175	26	(192,347)	(404)	180,172	378	75,239	297	45,143	240	97,057	104
2010						0		62,448	320	45,143	259	97,057	104
2011	2,320	500	22		0	(500)	-22	59,891	359	45,043	287	87,301	103
2012	185,228	14,817	8	(234,016)	(126)	219,199	118	72,900	117	81,208	165	99,292	106
2013						0		72,900	117	79,774	170	99,292	106
2014	25,386	25,932	102		0	(25,932)	-102	64,423	92	38,554	91	88,857	101
2015	175,765	3,815	2		0	(3,815)	-2	-9,915	-15	37,791	49	81,728	86
2016	1,777	1,513	85		0	(1,513)	-85	-10,420	-15	37,588	48	75,782	86
2017	94,792	16,272	17		0	(16,272)	-17	-7,200	-8	-9,506	-16	69,645	79
2018	27,907	3,207	11	(100)	(0)	(3,107)	-11	-6,964	-17	-10,128	-16	65,098	77
2019	198,689	34,582	17	(207,978)	(105)	173,396	87	51,339	48	29,738	30	71,469	78
2020	164,413	27,509	17		0	(27,509)	-17	47,593	37	24,999	26	65,970	69
2021	2412.62	8,825	366		0	(8,825)	-366	45,688	37	23,537	24	62,033	68
TOTAL	**1,720,952**	**178,540**	**10.37**	**-1,357,176**	**(78.86)**	**1,178,636**	**68.49**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 392.1 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - TRAILERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995													0
1996		47		(316)		269						134	0
1997						0		90	0			134	0
1998						0		90	0			134	0
1999						0		0	0	54	0	134	0
2000	826.93		0	(150)	(18)	150	18	50	18	84	51	140	51
2001	14,060		0	(1,701)	(12)	1,701	12	617	12	370	12	530	14
2002						0		617	12	370	12	530	14
2003						0		567	12	370	12	530	14
2004	310		0	(50)	(16)	50	16	17	16	380	13	434	14
2005	771		0		0	0	0	17	5	350	12	434	14
2006						0		17	5	10	5	434	14
2007	7,093		0	(2,500)	(35)	2,500	35	833	32	510	31	778	20
2008						0		833	35	510	31	778	20
2009	43,028		0	(22,510)	(52)	22,510	52	9,060	54	5,002	49	3,883	41
2010	13,681		0	(10,762)	(79)	10,762	79	12,647	67	7,154	56	4,743	48
2011	30,127		0	(13,422)	(45)	13,422	45	17,121	59	9,839	52	5,707	47
2012						0		8,061	55	9,339	54	5,707	47
2013	5,129		0	(601)	(12)	601	12	4,674	40	9,459	51	5,196	45
2014	18,787		0	(8,415)	(45)	8,415	45	3,005	38	6,640	49	5,489	45
2015						0		3,005	38	4,488	42	5,489	45
2016	13,283		0	(5,300)	(40)	5,300	40	4,572	43	2,863	38	5,473	45
2017	17,379		0	(2,830)	(16)	2,830	16	2,710	27	3,429	31	5,270	42
2018	2,402		0	(575)	(24)	575	24	2,902	26	3,424	33	4,935	41
2019	3,167		0	(3,775)	(119)	3,775	119	2,393	31	2,496	34	4,857	43
2020				(3,900)		3,900		2,750	148	3,276	45	4,797	45
2021						0		2,558	242	2,216	48	4,797	45
TOTAL	**170,044**	**47**	**0.03**	**-76,807**	**(45.17)**	**76,760**	**45.14**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 392.2 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	294,130	332	0	(31,226)	(11)	30,894	11					30,894	11
1996	387,552	3,363	1	(94,300)	(24)	90,937	23					60,915	18
1997	202,459	410	0	(35,010)	(17)	34,600	17	52,144	18			52,144	18
1998	436,319	1,086	0	(106,096)	(24)	105,010	24	76,849	22			65,360	20
1999	349,201	1,161	0	(56,913)	(16)	55,752	16	65,121	20	63,439	19	63,439	19
2000	706,715	795	0	(124,991)	(18)	124,196	18	94,986	19	82,099	20	73,565	19
2001	481,091	1,370	0	(84,395)	(18)	83,025	17	87,657	17	80,517	19	74,916	18
2002	385,991	789	0	(70,617)	(18)	69,828	18	92,350	18	87,562	19	74,280	18
2003	551,428	371	0	(94,188)	(17)	93,817	17	82,223	17	85,323	17	76,451	18
2004	703,343	158	0	(126,345)	(18)	126,187	18	96,611	18	99,410	18	81,425	18
2005	932,460		0	(189,285)	(20)	189,285	20	136,430	19	112,428	18	91,230	18
2006	634,321		0	(133,632)	(21)	133,632	21	149,701	20	122,550	19	94,764	19
2007	761,028		0	(158,848)	(21)	158,848	21	160,588	21	140,354	20	99,693	19
2008	856,416		0	(182,816)	(21)	182,816	21	158,432	21	158,154	20	105,630	19
2009	1,445,163		0	(319,046)	(22)	319,046	22	220,237	22	196,725	21	119,858	20
2010	491,271		0	(150,945)	(31)	150,945	31	217,602	23	189,057	23	121,801	20
2011	231,437		0	(62,100)	(27)	62,100	27	177,363	25	174,751	23	118,289	20
2012	484,401		0	(147,910)	(31)	147,910	31	120,318	30	172,563	25	119,935	21
2013	290,884		0	(96,441)	(33)	96,441		102,150	30	155,288	26	118,698	21
2014	293,262		0	(95,258)	(32)	95,258	32	113,203	32	110,531	31	117,526	22
2015	355,226		0	(75,648)	(21)	75,648	21	89,116	28	95,471	29	115,532	22
2016	1,270,125		0	(315,266)	(25)	315,266	25	162,057	25	146,105	27	124,611	22
2017	903,226		0	(273,191)	(30)	273,191	30	221,368	26	171,161	27	131,071	22
2018	683,049		0	(216,256)	(32)	216,256	32	268,238	28	195,124	28	134,620	23
2019	1,207,088	275	0	(231,840)	(19)	231,565	19	240,337	26	222,385	25	138,498	23
2020	884,714	4,290	0	(276,578)	(31)	272,288	31	240,036	26	261,713	26	143,644	23
2021	720,486	320	0	(202,344)	(28)	202,024		235,292	25	239,065	27	145,806	23
TOTAL	**16,942,782**	**14,720**	**0.09**	**-3,951,484**	**(23.32)**	**3,936,764**	**23.24**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 396.1 - GENERAL PLANT - POWER OPERATED EQUIPMENT - TRAILERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1996	0			(102)		102						102	0
1997	15,108		0	(8,030)	(53)	8,030	53						0
1998						0		2,711	54			4,066	54
1999	16315.67		0	(7,500)	(46)	7,500	46	5,177	49			5,211	50
2000	1,335		0	(450)	(34)	450	34	2,650	45	3,216	49	4,020	49
2001	6,275	149	2	(2,060)	(33)	1,911	30	3,287	41	3,578	46	3,599	46
2002	1066.23		0	(653)	(61)	653	61	1,005	35	2,103	42	3,108	46
2003	5,323		0	(1,112)	(21)	1,112	21	1,225	29	2,325	38	2,823	43
2004	5537.87		0	(150)	(3)	150	3	638	16	855	22	2,488	39
2005						0		421	12	765	21	2,488	39
2006						0		50	3	383	16	2,488	39
2007	2816.61		0	(1,189)	(42)	1,189	42	396	42	490	18	2,344	39
2008	9,947		0	(1,207)	(12)	1,207	12	799	19	509	14	2,230	35
2009	19,234		0		0	0	0	799	7	479	7	2,230	27
2010	5,619		0	(3,225)	(57)	3,225	57	1,477	13	1,124	15	2,321	29
2011	8,753		0	(1,350)	(15)	1,350	15	1,525	14	1,394	15	2,240	28
2012	5,017		0		0	0	0	1,525	24	1,156	12	2,240	26
2013						0		450	10	915	12	2,240	26
2014				(150)		150		50	3	945	24	2,079	26
2015	30,099		0	(10,500)	(35)	10,500	35	3,550	35	2,400	27	2,681	28
2016	44,293		0	(12,902)	(29)	12,902	29	7,851	32	4,710	30	3,362	29
2017	20,960		0	(10,700)	(51)	10,700	51	11,367	36	6,850	36	3,821	31
2018	34,098		0	(13,679)	(40)	13,679	40	12,427	38	9,586	37	4,401	32
2019	32,660		0	(7,650)	(23)	7,650	23	10,676	37	11,086	34	4,581	31
2020	37,294		0	(8,000)	(21)	8,000	21	9,776	28	10,586	31	4,761	30
2021	14,173		0	(5,810)	(41)	5,810	41	7,153	26	9,168	33	4,813	30
TOTAL	**315,924**	**149**	**0.05**	**-96,419**	**(30.52)**	**96,269**	**30.47**						

Montana-Dakota Utilities Co. - Gas Plant
ACCOUNT 396.2 - GENERAL PLANT - POWER OPERATED EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	757,409	10	0	(775,939)	(102)	775,929	102					775,929	102
1996	847,905	427	0	(632,158)	(75)	631,731	75					703,830	88
1997	1,325,620		0	(1,287,217)	(97)	1,287,217	97	898,293	92			898,293	92
1998	635,436	217	0	(520,006)	(82)	519,790	82	812,913	87			803,667	90
1999	1,604,865	16,945	1	(1,296,954)	(81)	1,280,009	80	1,029,005	87	898,935	87	898,935	87
2000	578,649		0	(446,315)	(77)	446,315	77	748,704	80	833,012	83	823,499	86
2001	1,331,620	1,185	0	(1,118,466)	(84)	1,117,281	84	947,868	81	930,122	85	865,467	86
2002	312,614	198	0	(203,872)	(65)	203,674	65	589,090	80	713,414	80	782,743	85
2003	1,489,389	637	0	(954,760)	(64)	954,123	64	758,359	73	800,280	75	801,785	81
2004	1,294,072		0	(1,087,417)	(84)	1,087,417	84	748,405	73	761,762	76	830,349	82
2005	1,593,725		0	(1,384,643)	(87)	1,384,643	87	1,142,061	78	949,428	79	880,739	82
2006	1,686,988		0	(1,363,963)	(81)	1,363,963	81	1,278,674	84	998,764	78	921,008	82
2007	1,938,280		0	(1,749,870)	(90)	1,749,870	90	1,499,492	86	1,308,003	82	984,766	83
2008	2,059,578		0	(1,894,912)	(92)	1,894,912	92	1,669,582	88	1,496,161	87	1,049,777	84
2009	1,888,458		0	(1,943,421)	(103)	1,943,421	103	1,862,734	95	1,667,362	91	1,109,353	86
2010	2,272,788		0	(1,969,431)	(87)	1,969,431	87	1,935,921	93	1,784,319	91	1,163,108	86
2011	2,313,463		0	(2,284,215)	(99)	2,284,215	99	2,065,689	96	1,968,370	94	1,229,055	87
2012	2,864,475		0	(2,613,890)	(91)	2,613,890	91	2,289,179	92	2,141,174	94	1,305,991	88
2013	135,654		0	(1,026,320)	(757)	1,026,320	757	1,974,808	111	1,967,455	104	1,291,271	91
2014	3,609,872		0	(2,615,759)	(72)	2,615,759	72	2,085,323	95	2,101,923	94	1,357,496	89
2015	2,897,221		0	(2,685,253)	(93)	2,685,253	93	2,109,111	95	2,245,087	95	1,420,722	89
2016	5,342,619		0	(3,047,345)	(57)	3,047,345	57	2,782,786	70	2,397,713	81	1,494,659	85
2017	1,968,418		0	(3,051,038)	(155)	3,051,038	155	2,927,879	86	2,485,143	89	1,562,328	88
2018	4,038,467		0	(3,612,285)	(89)	3,612,285	89	3,236,889	86	3,002,336	84	1,647,743	88
2019	5,104,954		0	(4,143,250)	(81)	4,143,250	81	3,602,191	97	3,307,834	85	1,747,563	88
2020	2,078,124		0	(1,387,298)	(67)	1,387,298	67	3,047,611	81	3,048,243	82	1,733,707	87
2021	3,664,618		0	(3,282,810)	(90)	3,282,810	90	2,937,786	81	3,095,336	92	1,791,081	87
TOTAL	**55,635,280**	**19,618**	**0.04**	**-48,378,807**	**(86.96)**	**48,359,189**	**86.92**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATIONS

MDU Gas

Account #: 374.20 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 65
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1977	11,086.99	6,721	8,648	0.7800	2,439	25.59	95	44.5
1978	32,936.47	19,596	25,211	0.7655	7,725	26.33	293	43.5
1979	703.19	410	528	0.7508	175	27.07	6	42.5
1980	1,196.55	684	881	0.7359	316	27.82	11	41.5
1981	1,257.25	704	906	0.7208	351	28.58	12	40.5
1982	9,392.30	5,151	6,627	0.7056	2,765	29.35	94	39.5
1983	1,756.61	942	1,212	0.6902	544	30.13	18	38.5
1984	3,781.55	1,983	2,551	0.6747	1,230	30.91	40	37.5
1985	1,520.05	779	1,002	0.6589	518	31.71	16	36.5
1986	4,821.22	2,410	3,100	0.6430	1,721	32.51	53	35.5
1987	2,724.79	1,328	1,708	0.6270	1,016	33.32	31	34.5
1988	104.71	50	64	0.6108	41	34.14	1	33.5
1989	52.84	24	31	0.5944	21	34.97	1	32.5
1990	1,367.84	614	791	0.5780	577	35.80	16	31.5
1991	207.89	91	117	0.5613	91	36.64	2	30.5
1992	892.88	378	486	0.5445	407	37.49	11	29.5
1994	2,478.24	983	1,265	0.5105	1,213	39.21	31	27.5
1995	1,270.26	487	627	0.4933	644	40.08	16	26.5
1996	2,817.57	1,042	1,341	0.4760	1,476	40.95	36	25.5
1997	10.13	4	5	0.4580	5	41.83	0	24.5
1998	423.48	145	187	0.4409	237	42.72	6	23.5
1999	103.23	34	44	0.4231	60	43.62	1	22.5
2000	7,121.24	2,244	2,887	0.4053	4,235	44.52	95	21.5
2001	1,417.26	427	549	0.3874	868	45.43	19	20.5
2002	5,947.12	1,707	2,196	0.3693	3,751	46.34	81	19.5
2003	1,495.91	408	525	0.3511	971	47.26	21	18.5
2004	24,900.55	6,442	8,288	0.3328	16,613	48.18	345	17.5
2005	11,746.86	2,871	3,694	0.3144	8,053	49.11	164	16.5

MDU Gas

Account #: 374.20 - Distribution - Land Rights

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 65
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2006	32,481.06	7,472	9,613	0.2960	22,868	50.05	457	15.5
2007	105,201.84	22,681	29,180	0.2774	76,022	50.99	1,491	14.5
2008	15,054.53	3,027	3,895	0.2587	11,160	51.93	215	13.5
2009	8,595.96	1,603	2,063	0.2400	6,533	52.88	124	12.5
2010	4,915.75	845	1,087	0.2211	3,829	53.83	71	11.5
2011	77,682.44	12,209	15,708	0.2022	61,975	54.78	1,131	10.5
2012	49,726.92	7,082	9,111	0.1832	40,616	55.74	729	9.5
2014	3,954.75	446	574	0.1450	3,381	57.67	59	7.5
2015	70,158.17	6,864	8,831	0.1259	61,327	58.64	1,046	6.5
2016	868.72	72	93	0.1066	776	59.61	13	5.5
2018	784,206.39	41,457	53,336	0.0680	730,871	61.56	11,872	3.5
TOTAL	1,286,381.51	162,420	208,959		1,077,422		18,723	

COMPOSITE ANNUAL ACCRUAL RATE	1.46%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.16
COMPOSITE AVERAGE AGE (YEARS)	8.63
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	56.79

MDU Gas

Account #: 375.00 - Distribution - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1918	513.89	514	514	1.0000	0		0	103.5
1919	526.74	527	527	1.0000	0		0	102.5
1920	539.91	540	540	1.0000	0		0	101.5
1921	553.41	553	553	1.0000	0		0	100.5
1922	567.24	567	567	1.0000	0		0	99.5
1923	581.42	581	581	1.0000	0		0	98.5
1924	595.96	596	596	1.0000	0		0	97.5
1925	610.86	611	611	1.0000	0		0	96.5
1926	626.13	626	626	1.0000	0		0	95.5
1927	641.78	642	642	1.0000	0		0	94.5
1928	657.83	658	658	1.0000	0		0	93.5
1929	674.27	668	674	1.0000	0	0.50	0	92.5
1930	691.13	684	691	1.0000	0	0.55	0	91.5
1931	708.41	699	708	1.0000	0	0.71	0	90.5
1932	726.12	714	726	1.0000	0	0.91	0	89.5
1933	744.27	729	744	1.0000	0	1.13	0	88.5
1934	762.88	744	763	1.0000	0	1.35	0	87.5
1935	781.95	760	782	1.0000	0	1.57	0	86.5
1936	801.50	775	802	1.0000	0	1.81	0	85.5
1937	821.54	791	822	1.0000	0	2.05	0	84.5
1938	842.08	807	842	1.0000	0	2.30	0	83.5
1939	863.13	823	863	1.0000	0	2.55	0	82.5
1940	884.71	840	885	1.0000	0	2.80	0	81.5
1946	884.71	815	885	1.0000	0	4.33	0	75.5
1947	884.71	811	885	1.0000	0	4.59	0	74.5
1948	884.71	807	885	1.0000	0	4.85	0	73.5
1949	552.52	501	553	1.0000	0	5.11	0	72.5
1950	959.12	865	959	1.0000	0	5.37	0	71.5

MDU Gas

Account #: 375.00 - Distribution - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1951	4,043.89	3,630	4,044	1.0000	0	5.64	0	70.5
1952	4,816.72	4,300	4,817	1.0000	0	5.91	0	69.5
1953	3,135.87	2,783	3,136	1.0000	0	6.18	0	68.5
1954	19,134.05	16,884	19,134	1.0000	0	6.47	0	67.5
1955	7,665.77	6,723	7,666	1.0000	0	6.76	0	66.5
1956	29,215.63	25,462	29,216	1.0000	0	7.07	0	65.5
1957	11,076.38	9,590	11,076	1.0000	0	7.38	0	64.5
1958	13,637.62	11,726	13,638	1.0000	0	7.71	0	63.5
1959	9,646.07	8,234	9,646	1.0000	0	8.05	0	62.5
1960	12,678.12	10,741	12,678	1.0000	0	8.41	0	61.5
1961	11,208.34	9,420	11,208	1.0000	0	8.78	0	60.5
1962	22,583.10	18,822	22,583	1.0000	0	9.16	0	59.5
1963	16,792.47	13,873	16,792	1.0000	0	9.56	0	58.5
1964	5,881.89	4,815	5,882	1.0000	0	9.98	0	57.5
1965	7,359.24	5,966	7,359	1.0000	0	10.42	0	56.5
1966	5,380.89	4,318	5,381	1.0000	0	10.87	0	55.5
1967	6,103.82	4,846	6,104	1.0000	0	11.34	0	54.5
1968	6,507.11	5,108	6,507	1.0000	0	11.82	0	53.5
1969	6,192.13	4,804	6,192	1.0000	0	12.33	0	52.5
1970	10,607.83	8,129	10,608	1.0000	0	12.85	0	51.5
1971	983.02	744	983	1.0000	0	13.39	0	50.5
1972	3,146.24	2,349	3,146	1.0000	0	13.94	0	49.5
1973	2,949.96	2,171	2,950	1.0000	0	14.52	0	48.5
1974	3,242.67	2,352	3,243	1.0000	0	15.10	0	47.5
1975	1,625.13	1,161	1,625	1.0000	0	15.71	0	46.5
1979	2,889.58	1,930	2,890	1.0000	0	18.27	0	42.5
1980	818.39	537	818	1.0000	0	18.94	0	41.5
1981	511.36	329	511	1.0000	0	19.63	0	40.5

MDU Gas

Account #: 375.00 - Distribution - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	5,805.37	3,659	5,805	1.0000	0	20.33	0	39.5
1984	6,446.16	3,895	6,311	0.9790	136	21.77	6	37.5
1985	26,544.90	15,683	25,412	0.9573	1,133	22.50	50	36.5
1986	13,663.63	7,887	12,780	0.9353	884	23.25	38	35.5
1987	426.93	241	390	0.9130	37	24.01	2	34.5
1988	1,012.80	557	902	0.8904	111	24.78	4	33.5
1989	7,653.95	4,098	6,640	0.8675	1,014	25.55	40	32.5
1990	1,453.64	757	1,227	0.8443	226	26.34	9	31.5
1991	13,418.12	6,797	11,014	0.8208	2,405	27.14	89	30.5
1992	13,547.05	6,664	10,797	0.7970	2,750	27.95	98	29.5
1993	43,075.76	20,550	33,297	0.7730	9,779	28.76	340	28.5
1994	58,579.02	27,068	43,857	0.7487	14,722	29.59	498	27.5
1996	2,413.38	1,042	1,688	0.6993	726	31.26	23	25.5
1997	12,484.05	5,194	8,416	0.6742	4,068	32.12	127	24.5
1998	2,173.67	870	1,410	0.6488	763	32.98	23	23.5
2000	680.28	251	406	0.5975	274	34.72	8	21.5
2003	22,150.44	7,091	11,489	0.5187	10,662	37.39	285	18.5
2004	4,110.00	1,248	2,022	0.4920	2,088	38.30	55	17.5
2005	13,949.02	4,004	6,488	0.4651	7,461	39.21	190	16.5
2006	9,930.00	2,684	4,350	0.4380	5,580	40.13	139	15.5
2007	2,467.27	625	1,013	0.4108	1,454	41.06	35	14.5
2008	34,980.07	8,276	13,409	0.3833	21,571	41.99	514	13.5
2010	10,680.56	2,162	3,503	0.3280	7,178	43.87	164	11.5
2011	131,096.36	24,277	39,335	0.3000	91,761	44.82	2,048	10.5
2012	57,817.49	9,706	15,726	0.2720	42,092	45.77	920	9.5
2013	37,411.97	5,629	9,121	0.2438	28,291	46.72	605	8.5
2014	239,703.28	31,879	51,653	0.2155	188,050	47.69	3,944	7.5
2015	396,972.28	45,830	74,258	0.1871	322,715	48.65	6,633	6.5

MDU Gas

Account #: 375.00 - Distribution - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2016	22,443.92	2,196	3,558	0.1585	18,886	49.62	381	5.5
2017	80,321.09	6,439	10,433	0.1299	69,888	50.59	1,381	4.5
2018	26,002.17	1,623	2,630	0.1012	23,372	51.57	453	3.5
2019	24,459.99	1,092	1,770	0.0723	22,690	52.54	432	2.5
2020	22,798.25	612	991	0.0435	21,807	53.52	407	1.5
2021	110,950.94	993	1,609	0.0145	109,342	54.51	2,006	0.5
TOTAL	1,707,340.03	472,570	673,425		1,033,915		21,947	

COMPOSITE ANNUAL ACCRUAL RATE	1.29%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	18.05
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	39.78

MDU Gas

Account #: 376.00 - Distribution - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -55%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1916	38,005.92	58,909	58,909	1.0000	0		0	105.5
1917	66,510.80	103,092	103,092	1.0000	0		0	104.5
1918	68,173.57	105,669	105,669	1.0000	0		0	103.5
1919	69,877.90	108,311	108,311	1.0000	0		0	102.5
1920	71,624.85	111,019	111,019	1.0000	0		0	101.5
1921	73,415.47	113,794	113,794	1.0000	0		0	100.5
1922	75,250.86	116,639	116,639	1.0000	0		0	99.5
1923	77,132.13	119,555	119,555	1.0000	0		0	98.5
1924	79,060.43	122,544	122,544	1.0000	0		0	97.5
1925	81,036.94	125,607	125,607	1.0000	0		0	96.5
1926	83,062.87	128,747	128,747	1.0000	0		0	95.5
1927	84,889.12	131,578	131,578	1.0000	0		0	94.5
1928	87,267.92	135,265	135,265	1.0000	0		0	93.5
1929	89,449.62	137,386	137,837	0.9942	810	0.50	810	92.5
1930	90,618.28	139,063	139,519	0.9933	939	0.55	939	91.5
1931	91,257.63	139,615	140,072	0.9903	1,377	0.71	1,377	90.5
1932	95,875.35	146,138	146,618	0.9866	1,989	0.91	1,989	89.5
1933	97,989.44	148,767	149,255	0.9827	2,629	1.13	2,329	88.5
1934	101,204.04	153,025	153,527	0.9787	3,339	1.35	2,480	87.5
1935	89,875.55	135,326	135,770	0.9746	3,537	1.57	2,251	86.5
1936	102,142.99	153,117	153,619	0.9703	4,702	1.81	2,601	85.5
1937	108,570.14	162,008	162,540	0.9659	5,744	2.05	2,801	84.5
1938	101,557.89	150,836	151,330	0.9613	6,084	2.30	2,647	83.5
1939	102,861.20	152,043	152,542	0.9568	6,893	2.55	2,703	82.5
1940	103,663.58	152,505	153,005	0.9522	7,674	2.80	2,743	81.5
1946	109,147.59	155,854	156,365	0.9243	12,814	4.33	2,958	75.5
1947	102,054.09	144,987	145,462	0.9196	12,721	4.59	2,772	74.5
1948	114,190.47	161,398	161,927	0.9149	15,068	4.85	3,109	73.5

MDU Gas

Account #: 376.00 - Distribution - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -55%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1949	106,229.49	149,366	149,855	0.9101	14,800	5.11	2,898	72.5
1950	355,485.71	497,197	498,827	0.9053	52,175	5.37	9,715	71.5
1951	320,038.95	445,234	446,694	0.9005	49,367	5.64	8,760	70.5
1952	506,337.85	700,550	702,847	0.8955	81,977	5.91	13,881	69.5
1953	385,002.27	529,664	531,400	0.8905	65,353	6.18	10,569	68.5
1954	461,337.15	630,969	633,038	0.8853	82,035	6.47	12,682	67.5
1955	766,085.60	1,041,414	1,044,829	0.8799	142,604	6.76	21,085	66.5
1956	646,702.34	873,586	876,451	0.8744	125,938	7.07	17,820	65.5
1957	352,654.49	473,248	474,800	0.8686	71,815	7.38	9,728	64.5
1958	436,038.84	581,122	583,027	0.8626	92,833	7.71	12,041	63.5
1959	570,477.55	754,810	757,285	0.8564	126,955	8.05	15,770	62.5
1960	701,230.69	920,794	923,813	0.8499	163,094	8.41	19,403	61.5
1961	545,479.14	710,589	712,919	0.8432	132,574	8.78	15,107	60.5
1962	832,138.17	1,074,978	1,078,503	0.8362	211,312	9.16	23,066	59.5
1963	701,324.27	898,052	900,996	0.8288	186,057	9.56	19,457	58.5
1964	717,167.59	909,887	912,871	0.8212	198,739	9.98	19,912	57.5
1965	629,900.85	791,449	794,043	0.8133	182,303	10.42	17,503	56.5
1966	481,202.94	598,486	600,448	0.8050	145,417	10.87	13,381	55.5
1967	573,587.38	705,798	708,112	0.7965	180,949	11.34	15,961	54.5
1968	727,011.56	884,605	887,505	0.7876	239,363	11.82	20,243	53.5
1969	647,163.14	778,250	780,801	0.7784	222,302	12.33	18,031	52.5
1970	2,680,793.80	3,184,413	3,194,853	0.7689	960,377	12.85	74,737	51.5
1971	672,290.56	788,391	790,975	0.7591	251,075	13.39	18,753	50.5
1972	1,636,023.75	1,892,973	1,899,179	0.7489	636,658	13.94	45,661	49.5
1973	871,203.97	993,983	997,242	0.7385	353,124	14.52	24,328	48.5
1974	460,172.75	517,398	519,095	0.7278	194,173	15.10	12,856	47.5
1975	805,975.98	892,495	895,421	0.7168	353,842	15.71	22,528	46.5
1976	1,121,570.89	1,222,414	1,226,422	0.7055	512,013	16.33	31,362	45.5

MDU Gas

Account #: 376.00 - Distribution - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -55%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1977	583,203.65	625,233	627,283	0.6939	276,683	16.96	16,315	44.5
1978	741,641.80	781,547	784,110	0.6821	365,435	17.61	20,755	43.5
1979	1,518,103.72	1,571,462	1,576,615	0.6700	776,446	18.27	42,501	42.5
1980	2,028,170.82	2,060,863	2,067,620	0.6577	1,076,045	18.94	56,801	41.5
1981	1,814,808.61	1,808,877	1,814,808	0.6452	998,146	19.63	50,843	40.5
1982	1,930,227.39	1,885,828	1,892,010	0.6324	1,099,842	20.33	54,093	39.5
1983	1,652,315.78	1,581,148	1,586,332	0.6194	974,758	21.04	46,319	38.5
1984	1,311,509.21	1,228,239	1,232,266	0.6062	800,574	21.77	36,776	37.5
1985	1,700,300.22	1,557,092	1,562,197	0.5928	1,073,268	22.50	47,691	36.5
1986	2,082,914.48	1,863,662	1,869,772	0.5791	1,358,746	23.25	58,438	35.5
1987	1,495,514.27	1,306,188	1,310,471	0.5653	1,007,577	24.01	41,968	34.5
1988	1,156,795.37	985,337	988,567	0.5513	804,466	24.78	32,470	33.5
1989	937,511.41	778,007	780,558	0.5372	672,584	25.55	26,321	32.5
1990	1,154,957.96	932,815	935,874	0.5228	854,311	26.34	32,433	31.5
1991	1,584,188.82	1,243,889	1,247,967	0.5082	1,207,526	27.14	44,495	30.5
1992	2,128,445.67	1,622,842	1,628,163	0.4935	1,670,928	27.95	59,793	29.5
1993	7,347,952.66	5,433,511	5,451,325	0.4786	5,938,001	28.76	206,459	28.5
1994	4,763,644.90	3,411,770	3,422,955	0.4636	3,960,694	29.59	133,870	27.5
1995	2,339,741.09	1,620,720	1,626,034	0.4484	2,000,565	30.42	65,763	26.5
1996	2,086,771.53	1,395,907	1,400,483	0.4330	1,834,013	31.26	58,663	25.5
1997	1,793,542.50	1,156,713	1,160,505	0.4174	1,619,486	32.12	50,427	24.5
1998	1,582,202.41	982,071	985,291	0.4018	1,467,122	32.98	44,492	23.5
1999	1,559,629.10	929,910	932,959	0.3859	1,484,467	33.84	43,863	22.5
2000	1,774,218.08	1,014,047	1,017,371	0.3699	1,732,667	34.72	49,905	21.5
2001	1,968,245.01	1,075,901	1,079,429	0.3538	1,971,351	35.60	55,370	20.5
2002	2,753,944.13	1,436,194	1,440,903	0.3376	2,827,711	36.50	77,482	19.5
2003	3,292,299.51	1,633,560	1,638,916	0.3212	3,464,148	37.39	92,640	18.5
2004	3,631,421.44	1,709,133	1,714,736	0.3046	3,913,967	38.30	102,194	17.5

MDU Gas

Account #: 376.00 - Distribution - Mains

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -55%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	4,757,333.13	2,116,712	2,123,652	0.2880	5,250,215	39.21	133,893	16.5
2006	3,600,696.04	1,508,792	1,513,738	0.2712	4,067,341	40.13	101,351	15.5
2007	3,300,813.95	1,297,040	1,301,292	0.2543	3,814,969	41.06	92,919	14.5
2008	7,267,448.10	2,664,955	2,673,692	0.2374	8,590,853	41.99	204,602	13.5
2009	3,092,287.13	1,052,278	1,055,728	0.2203	3,737,317	42.93	87,066	12.5
2010	4,051,042.80	1,270,952	1,275,119	0.2031	5,003,997	43.87	114,071	11.5
2011	5,954,325.09	1,709,077	1,714,680	0.1858	7,514,524	44.82	167,679	10.5
2012	16,073,142.32	4,182,067	4,195,778	0.1684	20,717,592	45.77	452,671	9.5
2013	12,595,253.33	2,937,506	2,947,136	0.1510	16,575,506	46.72	354,751	8.5
2014	36,155,477.79	7,453,064	7,477,499	0.1334	48,563,491	47.69	1,018,415	7.5
2015	11,874,663.18	2,124,918	2,131,885	0.1158	16,273,843	48.65	334,506	6.5
2016	7,780,568.91	1,179,922	1,183,790	0.0982	10,876,092	49.62	219,193	5.5
2017	10,129,649.30	1,258,646	1,262,773	0.0804	14,438,183	50.59	285,390	4.5
2018	22,247,014.79	2,152,870	2,159,928	0.0626	32,322,944	51.57	626,824	3.5
2019	19,000,794.59	1,315,031	1,319,342	0.0448	28,131,889	52.54	535,395	2.5
2020	12,943,487.08	538,118	539,883	0.0269	19,522,522	53.52	364,738	1.5
2021	16,798,817.05	233,051	233,815	0.0090	25,804,352	54.51	473,407	0.5
TOTAL	278,503,430.43	106,782,375	107,127,614		324,552,703		7,797,758	

COMPOSITE ANNUAL ACCRUAL RATE	2.80%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.38
COMPOSITE AVERAGE AGE (YEARS)	15.47
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	41.39

MDU Gas

Account #: 378.00 - Distribution - Meas. & Reg. Station Equip. - General

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1920	3,168.71	4,119	4,119	1.0000	0		0	102.5
1921	3,247.93	4,222	4,222	1.0000	0		0	101.5
1922	3,329.13	4,328	4,328	1.0000	0		0	100.5
1923	3,412.36	4,436	4,436	1.0000	0		0	99.5
1924	3,497.67	4,547	4,547	1.0000	0		0	98.5
1925	3,585.11	4,661	4,661	1.0000	0		0	97.5
1926	3,674.73	4,777	4,777	1.0000	0		0	96.5
1927	3,766.61	4,897	4,897	1.0000	0		0	95.5
1928	3,860.77	5,019	5,019	1.0000	0		0	94.5
1929	3,957.29	5,093	5,144	1.0000	0	0.50	0	92.5
1930	4,056.22	5,219	5,273	1.0000	0	0.51	0	91.5
1931	4,157.62	5,329	5,405	1.0000	0	0.70	0	90.5
1932	4,261.56	5,437	5,540	1.0000	0	0.93	0	89.5
1933	4,368.10	5,546	5,679	1.0000	0	1.17	0	88.5
1934	4,477.30	5,655	5,820	1.0000	0	1.42	0	87.5
1935	4,589.23	5,765	5,966	1.0000	0	1.69	0	86.5
1936	4,703.97	5,876	6,115	1.0000	0	1.95	0	85.5
1937	4,821.56	5,989	6,268	1.0000	0	2.22	0	84.5
1938	4,942.11	6,104	6,425	1.0000	0	2.50	0	83.5
1939	5,065.66	6,220	6,585	1.0000	0	2.78	0	82.5
1940	5,192.30	6,337	6,750	1.0000	0	3.06	0	81.5
1946	5,192.30	6,104	6,750	1.0000	0	4.78	0	75.5
1947	5,192.30	6,065	6,750	1.0000	0	5.07	0	74.5
1948	7,082.24	8,219	9,207	1.0000	0	5.37	0	73.5
1949	5,192.30	5,986	6,750	1.0000	0	5.66	0	72.5
1950	9,447.81	10,820	12,282	1.0000	0	5.95	0	71.5
1952	7,454.91	8,423	9,596	0.9902	95	6.55	15	69.5
1953	5,277.59	5,921	6,746	0.9833	115	6.85	17	68.5

MDU Gas

Account #: 378.00 - Distribution - Meas. & Reg. Station Equip. - General

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1954	13,267.21	14,780	16,839	0.9763	408	7.15	57	67.5
1955	20,157.67	22,293	25,399	0.9692	806	7.47	108	66.5
1956	14,042.15	15,414	17,562	0.9620	693	7.78	89	65.5
1957	5,153.29	5,613	6,396	0.9547	304	8.10	37	64.5
1958	10,849.14	11,725	13,358	0.9471	745	8.43	88	63.5
1959	16,644.98	17,842	20,328	0.9395	1,310	8.77	149	62.5
1960	25,153.30	26,736	30,462	0.9316	2,238	9.12	245	61.5
1961	18,046.93	19,016	21,666	0.9235	1,795	9.47	189	60.5
1962	14,493.61	15,135	17,244	0.9152	1,598	9.84	162	59.5
1963	13,430.27	13,894	15,830	0.9067	1,630	10.21	160	58.5
1964	11,058.96	11,330	12,909	0.8979	1,468	10.60	139	57.5
1965	25,585.90	25,950	29,566	0.8889	3,695	10.99	336	56.5
1966	11,501.19	11,544	13,152	0.8797	1,799	11.40	158	55.5
1967	9,168.89	9,103	10,372	0.8701	1,548	11.81	131	54.5
1968	13,995.34	13,739	15,654	0.8604	2,540	12.24	207	53.5
1969	20,113.63	19,516	22,235	0.8504	3,913	12.68	309	52.5
1970	22,456.29	21,525	24,524	0.8401	4,669	13.13	355	51.5
1971	21,588.19	20,432	23,280	0.8295	4,785	13.60	352	50.5
1972	16,079.12	15,020	17,112	0.8187	3,790	14.07	269	49.5
1973	13,257.50	12,216	13,918	0.8076	3,317	14.56	228	48.5
1974	46,340.78	42,098	47,964	0.7962	12,279	15.06	815	47.5
1975	15,254.65	13,655	15,558	0.7845	4,273	15.57	274	46.5
1976	39,729.01	35,023	39,903	0.7726	11,745	16.09	730	45.5
1977	25,003.86	21,694	24,717	0.7604	7,788	16.63	468	44.5
1978	13,141.04	11,215	12,778	0.7480	4,306	17.18	251	43.5
1979	6,555.77	5,500	6,266	0.7352	2,257	17.73	127	42.5
1980	30,346.14	25,008	28,492	0.7222	10,958	18.30	599	41.5
1981	2,665.85	2,157	2,457	0.7090	1,009	18.89	53	40.5

MDU Gas

Account #: 378.00 - Distribution - Meas. & Reg. Station Equip. - General

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	36,333.43	28,833	32,850	0.6955	14,383	19.48	738	39.5
1983	27,344.35	21,270	24,234	0.6817	11,314	20.08	563	38.5
1984	19,620.59	14,949	17,032	0.6677	8,475	20.70	409	37.5
1985	13,474.74	10,047	11,447	0.6535	6,070	21.32	285	36.5
1986	15,572.40	11,354	12,936	0.6390	7,308	21.96	333	35.5
1987	13,667.79	9,736	11,092	0.6243	6,676	22.60	295	34.5
1988	23,002.21	15,992	18,220	0.6093	11,683	23.26	502	33.5
1989	21,913.57	14,855	16,925	0.5941	11,562	23.93	483	32.5
1990	3,664.45	2,420	2,757	0.5787	2,007	24.60	82	31.5
1991	13,169.23	8,461	9,640	0.5631	7,480	25.29	296	30.5
1992	23,454.34	14,645	16,686	0.5472	13,805	25.98	531	29.5
1993	66,463.83	40,282	45,895	0.5312	40,508	26.69	1,518	28.5
1994	45,915.18	26,976	30,735	0.5149	28,955	27.40	1,057	27.5
1995	8,536.92	4,855	5,532	0.4984	5,566	28.13	198	26.5
1996	7,774.30	4,274	4,869	0.4818	5,237	28.86	181	25.5
1997	57,422.11	30,460	34,705	0.4649	39,944	29.60	1,350	24.5
1998	25,865.86	13,218	15,059	0.4479	18,566	30.35	612	23.5
1999	29,622.55	14,554	16,582	0.4306	21,927	31.10	705	22.5
2000	23,766.12	11,204	12,766	0.4132	18,130	31.87	569	21.5
2001	24,655.14	11,128	12,679	0.3956	19,373	32.64	594	20.5
2002	56,560.98	24,380	27,778	0.3778	45,752	33.42	1,369	19.5
2003	33,621.75	13,803	15,727	0.3598	27,982	34.21	818	18.5
2004	144,246.34	56,235	64,071	0.3417	123,449	35.01	3,527	17.5
2005	119,416.60	44,061	50,201	0.3234	105,041	35.81	2,933	16.5
2006	84,687.89	29,463	33,568	0.3049	76,526	36.62	2,090	15.5
2007	71,324.14	23,297	26,544	0.2863	66,178	37.44	1,768	14.5
2008	184,472.43	56,302	64,147	0.2675	175,667	38.26	4,591	13.5
2009	15,915.17	4,513	5,142	0.2485	15,547	39.09	398	12.5

MDU Gas

Account #: 378.00 - Distribution - Meas. & Reg. Station Equip. - General

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	68,458.32	17,923	20,420	0.2294	68,576	39.93	1,717	11.5
2011	485,802.54	116,518	132,754	0.2102	498,790	40.78	12,233	10.5
2012	233,267.24	50,788	57,865	0.1908	245,383	41.63	5,895	9.5
2013	153,075.78	29,917	34,086	0.1713	164,913	42.48	3,882	8.5
2014	127,843.09	22,116	25,198	0.1516	140,998	43.35	3,253	7.5
2015	286,863.38	43,144	49,155	0.1318	323,767	44.22	7,322	6.5
2016	116,909.82	14,923	17,003	0.1119	134,980	45.09	2,994	5.5
2017	169,682.22	17,775	20,251	0.0918	200,336	45.97	4,358	4.5
2018	395,764.35	32,339	36,845	0.0716	477,649	46.86	10,194	3.5
2019	130,155.54	7,618	8,680	0.0513	160,522	47.75	3,362	2.5
2020	403,040.55	14,194	16,172	0.0309	507,781	48.65	10,438	1.5
2021	736,486.98	8,668	9,876	0.0103	947,557	49.55	19,124	0.5
TOTAL	5,144,890.27	1,577,772	1,784,120		4,904,237		120,684	

COMPOSITE ANNUAL ACCRUAL RATE	2.35%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	15.47
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	38.21

MDU Gas

Account #: 379.00 - Distribution - Meas. & Reg. Station Equip. - City Gate

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1951	32,046.47	31,127	33,649	1.0000	0	3.37	0	70.5
1952	10,929.56	10,559	11,476	1.0000	0	3.60	0	69.5
1953	12,791.21	12,291	13,431	1.0000	0	3.82	0	68.5
1954	16,510.04	15,780	17,336	1.0000	0	4.04	0	67.5
1955	11,089.00	10,542	11,643	1.0000	0	4.26	0	66.5
1956	2,640.59	2,497	2,773	1.0000	0	4.48	0	65.5
1957	6,442.35	6,057	6,764	1.0000	0	4.70	0	64.5
1958	2,389.84	2,234	2,509	1.0000	0	4.93	0	63.5
1961	19,993.62	18,362	20,993	1.0000	0	5.64	0	60.5
1962	21,076.26	19,235	22,130	1.0000	0	5.89	0	59.5
1963	17,090.34	15,497	17,945	1.0000	0	6.14	0	58.5
1964	43,667.39	39,333	45,851	1.0000	0	6.40	0	57.5
1965	21,911.37	19,600	23,007	1.0000	0	6.66	0	56.5
1966	3,124.58	2,775	3,281	1.0000	0	6.94	0	55.5
1967	16,208.70	14,285	17,019	1.0000	0	7.23	0	54.5
1968	10,071.23	8,805	10,575	1.0000	0	7.53	0	53.5
1969	11,039.31	9,570	11,591	1.0000	0	7.85	0	52.5
1970	24,855.93	21,357	26,099	1.0000	0	8.18	0	51.5
1971	11,931.25	10,155	12,528	1.0000	0	8.52	0	50.5
1972	21,630.82	18,227	22,712	1.0000	0	8.89	0	49.5
1973	15,194.12	12,668	15,954	1.0000	0	9.27	0	48.5
1974	20,289.49	16,726	21,304	1.0000	0	9.67	0	47.5
1975	4,084.06	3,327	4,244	0.9897	44	10.09	4	46.5
1976	9,564.89	7,693	9,814	0.9772	229	10.53	22	45.5
1977	2,444.28	1,940	2,475	0.9642	92	10.99	8	44.5
1978	10,943.00	8,562	10,923	0.9507	567	11.47	49	43.5
1979	2,994.43	2,308	2,945	0.9366	199	11.96	17	42.5
1980	18,719.62	14,205	18,121	0.9219	1,535	12.48	123	41.5

MDU Gas

Account #: 379.00 - Distribution - Meas. & Reg. Station Equip. - City Gate

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1981	10,545.92	7,871	10,041	0.9068	1,032	13.01	79	40.5
1982	10,842.95	7,952	10,145	0.8911	1,240	13.57	91	39.5
1983	12,492.46	8,996	11,476	0.8749	1,641	14.14	116	38.5
1984	3,339.54	2,359	3,009	0.8582	497	14.73	34	37.5
1986	441.28	299	382	0.8235	82	15.95	5	35.5
1987	22.12	15	19	0.8056	5	16.59	0	34.5
1990	1,043.38	643	821	0.7490	275	18.58	15	31.5
1991	549.87	330	421	0.7294	156	19.27	8	30.5
1993	221,413.83	125,591	160,217	0.6892	72,267	20.69	3,493	28.5
1994	233,814.46	128,655	164,126	0.6685	81,379	21.42	3,800	27.5
1995	20,429.51	10,889	13,891	0.6476	7,560	22.16	341	26.5
1997	42,271.29	21,038	26,839	0.6047	17,546	23.67	741	24.5
1998	5,200.58	2,495	3,182	0.5828	2,278	24.44	93	23.5
2003	23,171.92	8,946	11,413	0.4691	12,918	28.45	454	18.5
2004	5,186.61	1,902	2,426	0.4455	3,020	29.28	103	17.5
2006	5,519.33	1,807	2,305	0.3977	3,491	30.97	113	15.5
2008	23,444.56	6,732	8,588	0.3489	16,028	32.69	490	13.5
2009	5,925.19	1,581	2,017	0.3242	4,205	33.57	125	12.5
2010	130,602.22	32,164	41,032	0.2992	96,101	34.45	2,790	11.5
2011	426,969.79	96,317	122,872	0.2741	325,446	35.33	9,211	10.5
2012	680,609.77	139,344	177,762	0.2487	536,879	36.23	14,820	9.5
2013	2,039,274.15	374,676	477,975	0.2232	1,663,263	37.13	44,801	8.5
2014	623,289.53	101,333	129,271	0.1975	525,183	38.03	13,809	7.5
2015	1,210,936.95	171,093	218,264	0.1717	1,053,220	38.94	27,044	6.5
2016	694,083.31	83,201	106,139	0.1456	622,648	39.86	15,620	5.5
2017	861,410.98	84,702	108,055	0.1195	796,427	40.79	19,527	4.5
2018	2,245,951.29	172,185	219,657	0.0931	2,138,592	41.71	51,268	3.5
2019	1,228,736.32	67,445	86,039	0.0667	1,204,134	42.65	28,235	2.5

MDU Gas

Account #: 379.00 - Distribution - Meas. & Reg. Station Equip. - City Gate

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2020	4,026.40	133	170	0.0401	4,058	43.59	93	1.5
2021	552,946.33	6,101	7,783	0.0134	572,811	44.53	12,864	0.5
TOTAL	11,726,165.59	2,022,513	2,545,424		9,767,050		250,406	

COMPOSITE ANNUAL ACCRUAL RATE	2.14%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.22
COMPOSITE AVERAGE AGE (YEARS)	8.60
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	37.61

MDU Gas

Account #: 380.00 - Distribution - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 50
Net Salvage: -100%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1920	21,368.77	42,738	42,738	1.0000	0		0	101.5
1921	22,014.61	44,029	44,029	1.0000	0		0	100.5
1922	22,564.97	45,130	45,130	1.0000	0		0	99.5
1923	23,129.10	46,258	46,258	1.0000	0		0	98.5
1924	23,707.33	47,415	47,415	1.0000	0		0	97.5
1925	24,300.01	48,600	48,600	1.0000	0		0	96.5
1926	24,907.51	49,815	49,815	1.0000	0		0	95.5
1927	25,530.20	51,060	51,060	1.0000	0		0	94.5
1928	26,135.35	52,271	52,271	1.0000	0		0	93.5
1929	26,789.56	53,579	53,579	1.0000	0		0	92.5
1930	26,915.61	53,831	53,831	1.0000	0		0	91.5
1931	28,127.56	56,255	56,255	1.0000	0		0	90.5
1932	28,851.97	57,704	57,704	1.0000	0		0	89.5
1933	29,554.47	59,109	59,109	1.0000	0	0.00	0	88.5
1934	30,315.73	60,025	60,631	1.0000	0	0.50	0	87.5
1935	31,006.76	60,773	62,014	1.0000	0	1.00	0	86.5
1936	31,883.71	61,854	63,767	1.0000	0	1.50	0	85.5
1937	32,603.56	62,599	65,207	1.0000	0	2.00	0	84.5
1938	33,476.47	63,724	66,953	1.0000	0	2.41	0	83.5
1939	34,124.37	64,562	68,249	1.0000	0	2.70	0	82.5
1940	33,123.32	62,308	66,247	1.0000	0	2.97	0	81.5
1946	33,187.28	60,572	66,375	1.0000	0	4.37	0	75.5
1947	32,799.30	59,576	65,599	1.0000	0	4.59	0	74.5
1948	33,095.49	59,821	66,191	1.0000	0	4.81	0	73.5
1949	33,810.35	60,811	67,621	1.0000	0	5.04	0	72.5
1950	17,403.23	31,144	34,806	1.0000	0	5.26	0	71.5
1951	90,240.97	160,664	180,482	1.0000	0	5.49	0	70.5
1952	110,843.54	196,316	221,687	1.0000	0	5.72	0	69.5

MDU Gas

Account #: 380.00 - Distribution - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 50
Net Salvage: -100%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1953	81,374.66	143,357	162,749	1.0000	0	5.96	0	68.5
1954	108,550.90	190,193	217,102	1.0000	0	6.20	0	67.5
1955	82,631.02	143,973	165,262	1.0000	0	6.44	0	66.5
1956	172,025.59	298,017	344,051	1.0000	0	6.69	0	65.5
1957	120,973.11	208,340	241,946	1.0000	0	6.94	0	64.5
1958	119,805.52	205,074	239,611	1.0000	0	7.21	0	63.5
1959	139,482.49	237,250	278,965	1.0000	0	7.48	0	62.5
1960	107,065.00	180,914	214,130	1.0000	0	7.76	0	61.5
1961	120,515.22	202,245	241,030	1.0000	0	8.05	0	60.5
1962	179,784.14	299,543	359,568	1.0000	0	8.35	0	59.5
1963	145,268.41	240,212	290,537	1.0000	0	8.66	0	58.5
1964	181,819.15	298,270	363,638	1.0000	0	8.99	0	57.5
1965	152,397.80	247,921	304,796	1.0000	0	9.33	0	56.5
1966	133,708.68	215,607	267,417	1.0000	0	9.69	0	55.5
1967	136,124.35	217,471	272,249	1.0000	0	10.06	0	54.5
1968	138,874.35	219,700	277,749	1.0000	0	10.45	0	53.5
1969	160,451.95	251,226	320,904	1.0000	0	10.86	0	52.5
1970	747,734.35	1,158,080	1,495,469	1.0000	0	11.28	0	51.5
1971	259,695.73	397,629	519,391	1.0000	0	11.72	0	50.5
1972	514,226.93	777,913	1,028,454	1.0000	0	12.18	0	49.5
1973	452,909.05	676,524	905,818	1.0000	0	12.66	0	48.5
1974	591,397.21	871,710	1,182,794	1.0000	0	13.15	0	47.5
1975	522,378.40	759,303	1,044,757	1.0000	0	13.66	0	46.5
1976	672,345.29	963,096	1,344,691	1.0000	0	14.19	0	45.5
1977	485,853.98	685,381	971,708	1.0000	0	14.73	0	44.5
1978	501,890.37	696,753	1,003,781	1.0000	0	15.29	0	43.5
1979	697,621.58	952,402	1,395,243	1.0000	0	15.87	0	42.5
1980	797,432.22	1,069,804	1,594,864	1.0000	0	16.46	0	41.5

MDU Gas

Account #: 380.00 - Distribution - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 50
Net Salvage: -100%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1981	709,530.20	934,677	1,419,060	1.0000	0	17.07	0	40.5
1982	780,469.24	1,008,760	1,560,938	1.0000	0	17.69	0	39.5
1983	905,277.44	1,147,113	1,810,555	1.0000	0	18.32	0	38.5
1984	780,514.17	968,807	1,561,028	1.0000	0	18.97	0	37.5
1985	864,317.72	1,050,001	1,728,635	1.0000	0	19.63	0	36.5
1986	682,970.48	811,318	1,359,535	0.9953	6,406	20.30	316	35.5
1987	565,956.49	656,814	1,100,632	0.9724	31,281	20.99	1,491	34.5
1988	565,874.97	640,959	1,074,063	0.9490	57,687	21.68	2,660	33.5
1989	477,939.40	527,829	884,489	0.9253	71,389	22.39	3,188	32.5
1990	503,894.31	542,012	908,255	0.9012	99,533	23.11	4,307	31.5
1991	690,667.75	722,770	1,211,155	0.8768	170,181	23.84	7,139	30.5
1992	830,064.95	844,094	1,414,458	0.8520	245,672	24.58	9,996	29.5
1993	961,747.30	949,165	1,590,527	0.8269	332,968	25.33	13,147	28.5
1994	1,982,685.87	1,896,516	3,178,014	0.8014	787,358	26.09	30,183	27.5
1995	926,473.61	857,706	1,437,268	0.7757	415,679	26.86	15,478	26.5
1996	1,513,820.74	1,354,315	2,269,442	0.7496	758,199	27.63	27,437	25.5
1997	1,428,610.20	1,233,068	2,066,267	0.7232	790,953	28.42	27,829	24.5
1998	1,207,810.61	1,003,998	1,682,411	0.6965	733,210	29.22	25,094	23.5
1999	998,645.40	797,950	1,337,134	0.6695	660,157	30.02	21,988	22.5
2000	1,072,359.14	821,926	1,377,312	0.6422	767,407	30.84	24,885	21.5
2001	1,181,525.00	866,723	1,452,377	0.6146	910,673	31.66	28,763	20.5
2002	1,381,516.64	967,521	1,621,286	0.5868	1,141,747	32.49	35,140	19.5
2003	2,115,730.48	1,410,733	2,363,982	0.5587	1,867,479	33.33	56,029	18.5
2004	2,516,125.70	1,592,514	2,668,594	0.5303	2,363,658	34.18	69,159	17.5
2005	2,733,402.78	1,636,656	2,742,564	0.5017	2,724,241	35.03	77,767	16.5
2006	2,854,720.43	1,610,941	2,699,473	0.4728	3,009,968	35.89	83,861	15.5
2007	2,964,362.05	1,569,840	2,630,599	0.4437	3,298,125	36.76	89,719	14.5
2008	3,687,280.35	1,823,583	3,055,800	0.4144	4,318,761	37.64	114,751	13.5

MDU Gas

Account #: 380.00 - Distribution - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 50
Net Salvage: -100%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	3,242,364.13	1,489,173	2,495,425	0.3848	3,989,304	38.52	103,570	12.5
2010	3,714,443.42	1,574,024	2,637,610	0.3550	4,791,277	39.41	121,587	11.5
2011	5,181,056.23	2,010,170	3,368,465	0.3251	6,993,648	40.30	173,538	10.5
2012	7,741,827.81	2,724,944	4,566,220	0.2949	10,917,436	41.20	264,983	9.5
2013	7,981,946.98	2,520,253	4,223,217	0.2645	11,740,677	42.11	278,834	8.5
2014	7,942,457.82	2,218,297	3,717,227	0.2340	12,167,689	43.02	282,854	7.5
2015	7,402,027.65	1,796,047	3,009,657	0.2033	11,794,398	43.93	268,458	6.5
2016	6,230,349.86	1,282,162	2,148,534	0.1724	10,312,166	44.86	229,899	5.5
2017	7,709,381.09	1,301,008	2,180,114	0.1414	13,238,648	45.78	289,173	4.5
2018	9,515,831.67	1,251,735	2,097,548	0.1102	16,934,116	46.71	362,526	3.5
2019	12,994,100.32	1,223,516	2,050,260	0.0789	23,937,941	47.65	502,412	2.5
2020	9,263,690.29	524,478	878,874	0.0474	17,648,507	48.58	363,253	1.5
2021	12,322,993.38	233,173	390,731	0.0159	24,255,255	49.53	489,738	0.5
TOTAL	148,582,912.62	64,977,739	102,882,033		194,283,793		4,501,152	

COMPOSITE ANNUAL ACCRUAL RATE	3.03%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	12.85
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	39.07

MDU Gas

Account #: 381.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 31
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1956	3.18	4	3	0.7785	1		1	66.5
1957	35.06	42	33	0.7787	9		9	65.5
1958	139.38	167	130	0.7786	37		37	64.5
1959	748.19	898	699	0.7786	199		199	63.5
1966	2,122.17	2,547	1,983	0.7786	564		564	56.5
1967	4,387.63	5,265	4,100	0.7786	1,166		1,166	55.5
1968	5,314.86	6,378	4,966	0.7786	1,412		1,412	54.5
1969	30,491.84	36,590	28,490	0.7786	8,100		8,100	53.5
1970	16,595.23	19,593	15,256	0.7661	4,658	0.50	4,658	51.5
1971	54,685.37	64,365	50,116	0.7637	15,506	0.59	15,506	50.5
1972	215,126.17	251,685	195,970	0.7591	62,182	0.78	62,182	49.5
1973	235,436.69	273,477	212,938	0.7537	69,586	0.99	69,586	48.5
1974	535,315.68	616,999	480,415	0.7479	161,964	1.22	132,240	47.5
1975	491,922.46	562,373	437,881	0.7418	152,426	1.47	103,905	46.5
1976	525,937.79	596,262	464,269	0.7356	166,857	1.71	97,439	45.5
1977	521,911.55	586,613	456,755	0.7293	169,539	1.96	86,318	44.5
1978	457,107.37	509,275	396,537	0.7229	151,992	2.22	68,512	43.5
1979	801,002.89	884,498	688,699	0.7165	272,505	2.47	110,155	42.5
1980	723,078.84	791,306	616,136	0.7101	251,559	2.73	92,175	41.5
1981	820,671.03	889,904	692,908	0.7036	291,898	2.99	97,712	40.5
1982	249,544.85	268,036	208,701	0.6969	90,753	3.25	27,903	39.5
1983	281,405.51	299,256	233,011	0.6900	104,676	3.53	29,671	38.5
1984	490,621.47	516,249	401,968	0.6828	186,778	3.82	48,930	37.5
1985	336,913.62	350,515	272,922	0.6751	131,374	4.12	31,858	36.5
1987	179,019.68	181,527	141,343	0.6579	73,481	4.80	15,293	34.5
1988	38,954.05	38,927	30,310	0.6484	16,435	5.18	3,170	33.5
1989	67,347.14	66,237	51,574	0.6382	29,243	5.59	5,229	32.5
1990	173,807.07	167,992	130,804	0.6272	77,764	6.03	12,894	31.5

MDU Gas

Account #: 381.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 31
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1991	451,268.25	427,980	333,239	0.6154	208,283	6.50	32,044	30.5
1992	501,456.97	465,882	362,750	0.6028	238,998	7.00	34,146	29.5
1993	762,703.39	692,941	539,546	0.5895	375,698	7.53	49,896	28.5
1994	797,282.93	707,062	550,541	0.5754	406,198	8.09	50,210	27.5
1995	719,317.72	621,518	483,934	0.5606	379,247	8.68	43,697	26.5
1996	1,120,784.19	941,660	733,206	0.5452	611,735	9.30	65,811	25.5
1997	993,926.89	810,365	630,976	0.5290	561,736	9.94	56,526	24.5
1998	1,212,044.43	956,891	745,066	0.5123	709,388	10.60	66,892	23.5
1999	1,647,981.98	1,257,019	978,755	0.4949	998,823	11.30	88,428	22.5
2000	1,699,981.44	1,249,836	973,162	0.4770	1,066,815	12.01	88,848	21.5
2001	1,624,923.03	1,148,595	894,333	0.4587	1,055,575	12.74	82,859	20.5
2002	1,491,981.11	1,011,204	787,355	0.4398	1,003,022	13.49	74,346	19.5
2003	1,308,712.99	847,958	660,247	0.4204	910,209	14.26	63,822	18.5
2004	1,317,427.34	813,412	633,349	0.4006	947,564	15.05	62,962	17.5
2005	2,356,109.38	1,381,294	1,075,520	0.3804	1,751,812	15.85	110,490	16.5
2006	1,978,551.25	1,097,033	854,185	0.3598	1,520,077	16.68	91,151	15.5
2007	8,121,135.50	4,239,514	3,301,021	0.3387	6,444,342	17.51	367,952	14.5
2008	9,647,859.22	4,717,981	3,673,570	0.3173	7,903,861	18.37	430,329	13.5
2009	634,511.44	288,980	225,009	0.2955	536,405	19.23	27,888	12.5
2010	1,002,550.07	422,388	328,885	0.2734	874,175	20.12	43,457	11.5
2011	2,878,063.85	1,112,857	866,506	0.2509	2,587,171	21.01	123,134	10.5
2012	3,372,612.29	1,185,589	923,137	0.2281	3,123,997	21.92	142,527	9.5
2013	2,625,400.08	829,491	645,868	0.2050	2,504,612	22.84	109,669	8.5
2014	3,368,376.35	942,955	734,215	0.1816	3,307,837	23.77	139,171	7.5
2015	3,584,227.96	872,948	679,705	0.1580	3,621,369	24.71	146,565	6.5
2016	2,169,597.78	448,684	349,360	0.1342	2,254,157	25.66	87,856	5.5
2017	2,453,490.27	416,469	324,276	0.1101	2,619,913	26.61	98,438	4.5
2018	4,266,733.96	564,947	439,886	0.0859	4,680,195	27.58	169,698	3.5

MDU Gas

Account #: 381.00 - Distribution - Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life

Survivor Curve: R3

ASL: 31

Net Salvage: -20%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2019	5,759,145.48	546,111	425,219	0.0615	6,485,756	28.55	227,169	2.5
2020	5,391,097.77	307,436	239,379	0.0370	6,229,938	29.53	210,993	1.5
2021	2,127,295.42	40,516	31,547	0.0124	2,521,207	30.51	82,641	0.5
TOTAL	84,646,197.49	39,354,497	30,642,661		70,932,776		4,596,439	

COMPOSITE ANNUAL ACCRUAL RATE	5.43%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	14.11
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.99

MDU Gas

Account #: 383.00 - Distribution - Service Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 58
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1946	15,910.38	14,436	15,840	0.9481	866	7.88	110	75.5
1947	21,130.25	19,074	20,928	0.9433	1,259	8.14	155	74.5
1948	21,130.25	18,973	20,817	0.9383	1,369	8.40	163	73.5
1949	21,130.25	18,869	20,703	0.9331	1,483	8.67	171	72.5
1950	20,806.94	18,476	20,272	0.9279	1,576	8.95	176	71.5
1951	25,809.25	22,783	24,998	0.9224	2,102	9.24	227	70.5
1952	27,034.58	23,719	26,025	0.9168	2,361	9.54	248	69.5
1953	34,556.19	30,126	33,055	0.9110	3,229	9.84	328	68.5
1954	28,772.56	24,918	27,340	0.9050	2,871	10.16	283	67.5
1955	45,241.58	38,910	42,692	0.8987	4,812	10.49	459	66.5
1956	84,767.21	72,376	79,412	0.8922	9,594	10.84	885	65.5
1957	37,420.53	31,709	34,791	0.8855	4,500	11.19	402	64.5
1958	29,209.77	24,555	26,942	0.8785	3,728	11.56	322	63.5
1959	45,612.86	38,027	41,724	0.8712	6,170	11.95	516	62.5
1960	65,506.02	54,139	59,402	0.8636	9,379	12.35	760	61.5
1961	43,013.80	35,227	38,652	0.8558	6,513	12.76	510	60.5
1962	44,518.05	36,114	39,625	0.8477	7,119	13.19	540	59.5
1963	34,689.57	27,862	30,571	0.8393	5,853	13.63	429	58.5
1964	27,309.47	21,708	23,818	0.8306	4,857	14.09	345	57.5
1965	25,859.29	20,333	22,310	0.8217	4,843	14.57	332	56.5
1966	16,810.75	13,069	14,340	0.8124	3,311	15.06	220	55.5
1967	24,612.24	18,910	20,749	0.8029	5,094	15.56	327	54.5
1968	27,055.47	20,534	22,530	0.7931	5,879	16.08	366	53.5
1969	18,693.34	14,007	15,368	0.7830	4,260	16.61	256	52.5
1970	29,227.68	21,611	23,712	0.7726	6,978	17.16	407	51.5
1971	35,406.49	25,820	28,330	0.7620	8,847	17.72	499	50.5
1972	80,853.58	58,120	63,770	0.7512	21,126	18.29	1,155	49.5
1973	70,100.59	49,645	54,471	0.7400	19,135	18.88	1,013	48.5

MDU Gas

Account #: 383.00 - Distribution - Service Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 58
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1974	92,738.06	64,669	70,956	0.7287	26,419	19.48	1,356	47.5
1975	90,094.50	61,826	67,836	0.7171	26,764	20.09	1,332	46.5
1976	78,854.81	53,220	58,393	0.7053	24,404	20.72	1,178	45.5
1977	80,963.80	53,710	58,931	0.6932	26,081	21.36	1,221	44.5
1978	62,031.78	40,423	44,353	0.6810	20,781	22.00	944	43.5
1979	84,250.92	53,896	59,135	0.6685	29,328	22.66	1,294	42.5
1980	124,441.35	78,096	85,688	0.6558	44,976	23.33	1,927	41.5
1981	125,645.98	77,304	84,819	0.6429	47,109	24.01	1,962	40.5
1982	63,231.65	38,113	41,818	0.6299	24,575	24.71	995	39.5
1983	91,093.22	53,751	58,976	0.6166	36,672	25.41	1,443	38.5
1984	116,925.53	67,490	74,051	0.6032	48,721	26.12	1,866	37.5
1985	97,342.40	54,919	60,258	0.5896	41,951	26.84	1,563	36.5
1986	53,198.01	29,312	32,161	0.5758	23,697	27.56	860	35.5
1987	38,224.55	20,551	22,548	0.5618	17,587	28.30	621	34.5
1988	44,368.62	23,254	25,515	0.5477	21,072	29.05	725	33.5
1989	38,988.02	19,902	21,836	0.5334	19,101	29.80	641	32.5
1990	12,409.21	6,163	6,762	0.5190	6,268	30.57	205	31.5
1991	80,674.36	38,938	42,723	0.5044	41,985	31.34	1,340	30.5
1992	97,836.09	45,840	50,297	0.4896	52,431	32.12	1,632	29.5
1993	136,183.68	61,866	67,880	0.4747	75,113	32.91	2,283	28.5
1994	128,747.54	56,633	62,138	0.4597	73,046	33.70	2,167	27.5
1995	121,108.17	51,512	56,519	0.4445	70,644	34.51	2,047	26.5
1996	129,613.49	53,228	58,403	0.4291	77,692	35.32	2,200	25.5
1997	156,500.78	61,952	67,974	0.4137	96,352	36.13	2,667	24.5
1998	184,970.52	70,458	77,308	0.3980	116,911	36.96	3,163	23.5
1999	133,798.63	48,951	53,709	0.3823	86,779	37.79	2,296	22.5
2000	142,958.23	50,131	55,004	0.3664	95,102	38.63	2,462	21.5
2001	99,623.44	33,409	36,657	0.3504	67,948	39.48	1,721	20.5

MDU Gas

Account #: 383.00 - Distribution - Service Regulators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 58
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	114,771.27	36,718	40,288	0.3343	80,222	40.33	1,989	19.5
2003	181,308.21	55,188	60,553	0.3181	129,821	41.19	3,152	18.5
2004	111,550.24	32,208	35,339	0.3017	81,789	42.05	1,945	17.5
2005	202,172.43	55,185	60,550	0.2852	151,731	42.92	3,535	16.5
2006	221,446.20	56,932	62,467	0.2687	170,052	43.80	3,883	15.5
2007	151,030.23	36,417	39,957	0.2520	118,624	44.68	2,655	14.5
2008	303,487.17	68,299	74,939	0.2352	243,723	45.57	5,348	13.5
2009	105,664.35	22,071	24,217	0.2183	86,731	46.46	1,867	12.5
2010	314,153.35	60,513	66,395	0.2013	263,466	47.36	5,563	11.5
2011	575,614.51	101,465	111,329	0.1842	493,067	48.26	10,216	10.5
2012	678,869.47	108,507	119,055	0.1670	593,758	49.17	12,075	9.5
2013	505,532.32	72,451	79,494	0.1498	451,315	50.08	9,011	8.5
2014	674,903.22	85,524	93,838	0.1324	614,810	51.00	12,055	7.5
2015	862,194.75	94,880	104,103	0.1150	801,202	51.92	15,431	6.5
2016	345,974.71	32,278	35,416	0.0975	327,858	52.85	6,204	5.5
2017	440,610.32	33,697	36,973	0.0799	425,668	53.78	7,916	4.5
2018	736,451.26	43,889	48,155	0.0623	725,118	54.71	13,254	3.5
2019	1,303,718.29	55,595	60,999	0.0446	1,307,905	55.64	23,505	2.5
2020	791,461.97	20,287	22,259	0.0268	808,776	56.58	14,293	1.5
2021	469,994.45	4,025	4,417	0.0089	489,078	57.53	8,502	0.5
TOTAL	12,799,915.00	3,259,696	3,576,574		9,863,336		218,114	

COMPOSITE ANNUAL ACCRUAL RATE	1.70%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.28
COMPOSITE AVERAGE AGE (YEARS)	16.65
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	43.93

MDU Gas

Account #: 385.00 - Distribution - Industrial Meas. & Reg. Station Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1951	2,680.88	2,872	2,949	1.0000	0	1.04	0	70.5
1952	4,868.52	5,182	5,355	1.0000	0	1.29	0	69.5
1953	2,163.85	2,288	2,380	1.0000	0	1.55	0	68.5
1954	745.37	783	820	1.0000	0	1.82	0	67.5
1955	2,362.95	2,463	2,599	1.0000	0	2.10	0	66.5
1956	6,597.03	6,826	7,257	1.0000	0	2.37	0	65.5
1957	6,061.41	6,225	6,668	1.0000	0	2.66	0	64.5
1958	4,054.18	4,132	4,460	1.0000	0	2.94	0	63.5
1959	4,573.78	4,625	5,031	1.0000	0	3.23	0	62.5
1960	12,461.11	12,502	13,707	1.0000	0	3.52	0	61.5
1961	8,196.22	8,158	9,016	1.0000	0	3.81	0	60.5
1962	1,763.36	1,741	1,940	1.0000	0	4.10	0	59.5
1963	10,583.20	10,365	11,642	1.0000	0	4.39	0	58.5
1964	17,835.10	17,324	19,619	1.0000	0	4.68	0	57.5
1965	11,173.34	10,762	12,291	1.0000	0	4.97	0	56.5
1966	5,393.07	5,150	5,894	0.9935	39	5.27	7	55.5
1967	4,491.43	4,252	4,866	0.9848	75	5.57	13	54.5
1968	9,911.64	9,299	10,641	0.9760	262	5.88	44	53.5
1969	612.68	570	652	0.9670	22	6.20	4	52.5
1970	11,417.57	10,512	12,029	0.9578	530	6.52	81	51.5
1971	5,523.88	5,035	5,762	0.9483	314	6.85	46	50.5
1972	7,541.45	6,804	7,785	0.9385	510	7.19	71	49.5
1973	6,520.05	5,819	6,659	0.9284	513	7.55	68	48.5
1974	1,656.04	1,461	1,672	0.9180	149	7.91	19	47.5
1975	13,094.98	11,420	13,068	0.9072	1,336	8.29	161	46.5
1980	6,543.69	5,331	6,101	0.8476	1,097	10.37	106	41.5
1981	242.64	195	223	0.8344	44	10.83	4	40.5
1983	172.25	134	153	0.8068	37	11.80	3	38.5

MDU Gas

Account #: 385.00 - Distribution - Industrial Meas. & Reg. Station Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1984	19,084.23	14,535	16,633	0.7923	4,360	12.30	354	37.5
1985	78,994.35	59,034	67,553	0.7774	19,341	12.82	1,508	36.5
1986	4,425.00	3,242	3,710	0.7621	1,158	13.36	87	35.5
1987	16,965.27	12,173	13,929	0.7464	4,733	13.91	340	34.5
1988	19,930.67	13,991	16,010	0.7303	5,914	14.47	409	33.5
1989	103.59	71	81	0.7137	33	15.05	2	32.5
1990	15,148.91	10,147	11,611	0.6968	5,053	15.64	323	31.5
1991	17,900.06	11,691	13,378	0.6794	6,312	16.25	388	30.5
1992	11,678.51	7,428	8,500	0.6617	4,346	16.87	258	29.5
1993	12,614.53	7,804	8,930	0.6436	4,946	17.50	283	28.5
1994	8,709.85	5,234	5,989	0.6251	3,592	18.15	198	27.5
1995	26,585.34	15,493	17,729	0.6062	11,515	18.81	612	26.5
1996	28,112.90	15,864	18,154	0.5870	12,771	19.48	656	25.5
1997	12,388.03	6,758	7,733	0.5675	5,894	20.16	292	24.5
1998	15,936.47	8,389	9,599	0.5476	7,931	20.86	380	23.5
1999	9,754.16	4,945	5,658	0.5274	5,071	21.57	235	22.5
2000	3,184.71	1,552	1,775	0.5068	1,728	22.28	78	21.5
2001	6,751.97	3,154	3,609	0.4860	3,818	23.01	166	20.5
2002	1,505.72	673	770	0.4648	886	23.75	37	19.5
2003	55,438.44	23,625	27,034	0.4433	33,948	24.50	1,385	18.5
2004	8,460.91	3,429	3,923	0.4215	5,384	25.26	213	17.5
2006	48,061.67	17,425	19,939	0.3772	32,928	26.82	1,228	15.5
2008	153,039.71	48,795	55,836	0.3317	112,508	28.41	3,961	13.5
2013	126,104.75	25,885	29,620	0.2135	109,095	32.54	3,353	8.5
2014	746,852.02	135,828	155,429	0.1892	666,108	33.39	19,951	7.5
2015	72,902.60	11,537	13,202	0.1646	66,991	34.25	1,956	6.5
2016	19,959.39	2,683	3,070	0.1399	18,885	35.11	538	5.5
2017	106,033.12	11,708	13,397	0.1149	103,239	35.98	2,869	4.5

MDU Gas

Account #: 385.00 - Distribution - Industrial Meas. & Reg. Station Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	94,659.57	8,159	9,337	0.0897	94,789	36.87	2,571	3.5
2019	369,319.28	22,821	26,114	0.0643	380,137	37.75	10,069	2.5
2020	277,148.73	10,311	11,799	0.0387	293,065	38.65	7,583	1.5
2021	193,419.80	2,406	2,753	0.0129	210,009	39.55	5,310	0.5
TOTAL	2,750,415.93	689,019	784,042		2,241,416		68,220	

COMPOSITE ANNUAL ACCRUAL RATE	2.48%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	11.83
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	30.89

MDU Gas

Account #: 386.10 - Distribution - Misc. Property on Customer's Premises

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1996	1,679.84	1,680	1,680	1.0000	0		0	26.5
TOTAL	1,679.84	1,680	1,680		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	26.50
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	0.00

MDU Gas

Account #: 387.20 - Distribution - Other Distribution Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1950	6,095.32	6,095	6,095	1.0000	0		0	71.5
1951	5,583.99	5,584	5,584	1.0000	0		0	70.5
1952	3,835.98	3,836	3,836	1.0000	0		0	69.5
1953	285.53	286	286	1.0000	0		0	68.5
1955	5,026.90	5,027	5,027	1.0000	0		0	66.5
1956	826.65	827	827	1.0000	0		0	65.5
1958	3,434.38	3,434	3,434	1.0000	0		0	63.5
1959	3,727.71	3,728	3,728	1.0000	0		0	62.5
1960	6,953.03	6,953	6,953	1.0000	0		0	61.5
1961	857.93	858	858	1.0000	0		0	60.5
1962	1,632.84	1,633	1,633	1.0000	0		0	59.5
1963	6,585.10	6,585	6,585	1.0000	0		0	58.5
1964	1,401.51	1,402	1,402	1.0000	0		0	57.5
1965	2,334.15	2,334	2,334	1.0000	0		0	56.5
1966	355.00	355	355	1.0000	0		0	55.5
1967	1,372.26	1,372	1,372	1.0000	0		0	54.5
1968	474.99	475	475	1.0000	0		0	53.5
1969	205.76	206	206	1.0000	0		0	52.5
1970	1,862.30	1,862	1,862	1.0000	0		0	51.5
1971	82.78	81	83	1.0000	0	0.50	0	50.5
1978	193.93	182	194	1.0000	0	1.79	0	43.5
1979	11,269.15	10,501	11,269	1.0000	0	2.05	0	42.5
1980	8,199.96	7,571	8,200	1.0000	0	2.30	0	41.5
1981	18,505.15	16,928	18,505	1.0000	0	2.56	0	40.5
1982	24,398.55	22,111	24,399	1.0000	0	2.81	0	39.5
1983	34,342.71	30,822	34,343	1.0000	0	3.08	0	38.5
1984	42,801.42	38,025	42,801	1.0000	0	3.35	0	37.5
1985	51,766.92	45,499	51,767	1.0000	0	3.63	0	36.5

MDU Gas

Account #: 387.20 - Distribution - Other Distribution Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1986	71,344.20	61,985	71,344	1.0000	0	3.94	0	35.5
1987	2,462.33	2,113	2,462	1.0000	0	4.26	0	34.5
1988	11,522.03	9,752	11,522	1.0000	0	4.61	0	33.5
1989	9,146.81	7,627	9,102	0.9951	44	4.99	9	32.5
1990	13,687.46	11,227	13,400	0.9790	288	5.39	53	31.5
1991	3,018.54	2,432	2,903	0.9616	116	5.83	20	30.5
1992	8,276.24	6,539	7,804	0.9429	472	6.30	75	29.5
1993	8,327.43	6,440	7,686	0.9230	641	6.80	94	28.5
1994	33,680.29	25,450	30,374	0.9018	3,306	7.33	451	27.5
1995	16,037.28	11,817	14,104	0.8794	1,933	7.89	245	26.5
1996	51,301.41	36,789	43,908	0.8559	7,394	8.49	871	25.5
1997	38,312.61	26,681	31,844	0.8312	6,469	9.11	710	24.5
1998	4,950.24	3,341	3,987	0.8054	963	9.76	99	23.5
2000	7,454.90	4,691	5,598	0.7509	1,857	11.12	167	21.5
2002	1,415.33	822	981	0.6930	435	12.58	35	19.5
2005	9,902.45	4,980	5,944	0.6002	3,959	14.91	265	16.5
2006	1,748.39	832	993	0.5679	756	15.73	48	15.5
2015	78,459.03	16,441	19,623	0.2501	58,836	23.71	2,481	6.5
2016	61,480.35	10,942	13,059	0.2124	48,421	24.66	1,963	5.5
2017	699.18	102	122	0.1744	577	25.62	23	4.5
2021	1,107,722.01	18,167	21,682	0.0196	1,086,040	29.51	36,805	0.5

MDU Gas

Account #: 387.20 - Distribution - Other Distribution Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R3
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	1,785,360.41	493,740	562,854		1,222,507		44,414	

COMPOSITE ANNUAL ACCRUAL RATE	2.49%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	11.49
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	21.70

MDU Gas

Account #: 390.00 - General - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 45
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1928	11,198.16	11,198	11,198	1.0000	0		0	93.5
1929	11,478.12	11,478	11,478	1.0000	0		0	92.5
1930	11,765.07	11,765	11,765	1.0000	0		0	91.5
1931	12,059.19	12,059	12,059	1.0000	0		0	90.5
1932	12,360.67	12,361	12,361	1.0000	0		0	89.5
1933	12,669.69	12,670	12,670	1.0000	0		0	88.5
1934	12,986.42	12,986	12,986	1.0000	0		0	87.5
1935	13,311.09	13,311	13,311	1.0000	0		0	86.5
1936	13,643.86	13,644	13,644	1.0000	0		0	85.5
1937	13,984.96	13,985	13,985	1.0000	0		0	84.5
1938	14,334.59	14,175	14,335	1.0000	0	0.50	0	83.5
1939	14,692.95	14,527	14,693	1.0000	0	0.51	0	82.5
1940	15,060.28	14,840	15,060	1.0000	0	0.66	0	81.5
1944	744.81	718	745	1.0000	0	1.62	0	77.5
1946	15,060.28	14,337	15,060	1.0000	0	2.16	0	75.5
1947	15,060.28	14,245	15,060	1.0000	0	2.44	0	74.5
1948	15,060.28	14,151	15,060	1.0000	0	2.72	0	73.5
1949	3,633.90	3,392	3,634	1.0000	0	3.00	0	72.5
1950	8,818.31	8,174	8,818	1.0000	0	3.29	0	71.5
1951	4,229.80	3,894	4,230	1.0000	0	3.57	0	70.5
1952	8,328.12	7,614	8,328	1.0000	0	3.86	0	69.5
1953	20,108.62	18,254	20,109	1.0000	0	4.15	0	68.5
1954	3,150.93	2,840	3,151	1.0000	0	4.44	0	67.5
1955	67,709.22	60,591	67,709	1.0000	0	4.73	0	66.5
1956	86,710.76	77,033	86,711	1.0000	0	5.02	0	65.5
1957	2,936.53	2,590	2,937	1.0000	0	5.32	0	64.5
1958	1,273.68	1,115	1,274	1.0000	0	5.61	0	63.5
1959	1,421.98	1,235	1,422	1.0000	0	5.91	0	62.5

MDU Gas

Account #: 390.00 - General - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 45
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	12,556.02	10,823	12,556	1.0000	0	6.21	0	61.5
1961	5,868.26	5,018	5,868	1.0000	0	6.52	0	60.5
1962	2,613.71	2,217	2,614	1.0000	0	6.83	0	59.5
1963	12,785.33	10,754	12,785	1.0000	0	7.15	0	58.5
1964	9,937.61	8,286	9,938	1.0000	0	7.48	0	57.5
1965	49,870.40	41,213	49,870	1.0000	0	7.81	0	56.5
1966	37,894.62	31,026	37,895	1.0000	0	8.16	0	55.5
1967	6,603.48	5,355	6,603	1.0000	0	8.51	0	54.5
1968	2,370.54	1,903	2,371	1.0000	0	8.87	0	53.5
1969	5,925.76	4,708	5,926	1.0000	0	9.25	0	52.5
1970	45,486.46	35,746	45,486	1.0000	0	9.64	0	51.5
1971	1,119.99	870	1,120	1.0000	0	10.03	0	50.5
1972	178,819.27	137,313	178,819	1.0000	0	10.45	0	49.5
1973	25,832.84	19,594	25,833	1.0000	0	10.87	0	48.5
1974	15,277.76	11,440	15,278	1.0000	0	11.30	0	47.5
1975	4,750.43	3,510	4,750	1.0000	0	11.75	0	46.5
1976	13,452.36	9,801	13,452	1.0000	0	12.22	0	45.5
1977	3,318.56	2,383	3,319	1.0000	0	12.69	0	44.5
1978	39,753.00	28,110	39,753	1.0000	0	13.18	0	43.5
1979	2,388.45	1,662	2,376	0.9948	12	13.68	1	42.5
1980	29,303.93	20,059	28,671	0.9784	633	14.20	45	41.5
1981	7,513.80	5,055	7,226	0.9616	288	14.73	20	40.5
1982	11,047.24	7,299	10,433	0.9444	614	15.27	40	39.5
1983	1,965.82	1,275	1,822	0.9268	144	15.82	9	38.5
1984	23,063.40	14,664	20,960	0.9088	2,104	16.39	128	37.5
1986	111,357.97	67,900	97,055	0.8716	14,303	17.56	814	35.5
1987	24,357.94	14,525	20,761	0.8523	3,597	18.17	198	34.5
1988	23,714.81	13,816	19,748	0.8327	3,966	18.78	211	33.5

MDU Gas

Account #: 390.00 - General - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 45
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1989	15,050.58	8,558	12,233	0.8128	2,818	19.41	145	32.5
1990	4,011.80	2,224	3,179	0.7924	833	20.05	42	31.5
1991	36,391.88	19,648	28,084	0.7717	8,307	20.70	401	30.5
1992	686.48	361	515	0.7507	171	21.37	8	29.5
1993	111,240.44	56,753	81,122	0.7292	30,119	22.04	1,366	28.5
1994	30,782.37	15,236	21,779	0.7075	9,004	22.73	396	27.5
1998	1,883.54	813	1,163	0.6172	721	25.57	28	23.5
1999	10,810.87	4,492	6,420	0.5939	4,391	26.30	167	22.5
2000	133,614.95	53,300	76,186	0.5702	57,429	27.05	2,123	21.5
2001	123,952.73	47,369	67,708	0.5462	56,245	27.80	2,023	20.5
2002	3,360,893.35	1,227,375	1,754,382	0.5220	1,606,511	28.57	56,238	19.5
2004	3,208.31	1,061	1,517	0.4727	1,692	30.12	56	17.5
2005	39,180.19	12,269	17,538	0.4476	21,643	30.91	700	16.5
2006	16,639.46	4,916	7,026	0.4223	9,613	31.71	303	15.5
2007	4,238,356.15	1,176,258	1,681,318	0.3967	2,557,038	32.51	78,651	14.5
2008	162,026.39	42,038	60,088	0.3709	101,938	33.32	3,059	13.5
2009	1,461,409.05	352,481	503,829	0.3448	957,580	34.15	28,043	12.5
2010	1,213,110.45	270,242	386,278	0.3184	826,832	34.98	23,640	11.5
2011	9,583.55	1,957	2,797	0.2919	6,787	35.81	190	10.5
2012	216,445.76	40,136	57,370	0.2651	159,076	36.66	4,340	9.5
2013	352,831.01	58,755	83,984	0.2380	268,847	37.51	7,168	8.5
2014	48,149.52	7,100	10,149	0.2108	38,001	38.36	991	7.5
2015	88,907.29	11,402	16,298	0.1833	72,609	39.23	1,851	6.5
2016	25,039.35	2,727	3,897	0.1556	21,142	40.10	527	5.5
2017	222,701.59	19,909	28,457	0.1278	194,244	40.98	4,740	4.5
2018	1,042,060.64	72,689	103,901	0.0997	938,160	41.86	22,411	3.5
2019	220,803.25	11,036	15,775	0.0714	205,028	42.75	4,796	2.5
2020	1,426,738.07	42,917	61,345	0.0430	1,365,393	43.65	31,283	1.5

MDU Gas

Account #: 390.00 - General - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 45
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2021	17,684.99	178	254	0.0144	17,431	44.55	391	0.5
TOTAL	15,766,936.32	4,479,705	6,201,672		9,565,265		277,543	

COMPOSITE ANNUAL ACCRUAL RATE	1.76%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	16.01
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.21

MDU Gas

Account #: 391.10 - General - Office Furniture & Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	134,717.36	130,227	90,021	0.6682	44,697	0.50	44,697	14.5
2008	14,663.46	13,197	9,123	0.6221	5,541	1.50	3,694	13.5
2011	3,687.21	2,581	1,784	0.4839	1,903	4.50	423	10.5
2012	2,878.08	1,823	1,260	0.4378	1,618	5.50	294	9.5
2013	8,972.57	5,084	3,515	0.3917	5,458	6.50	840	8.5
2014	6,598.93	3,299	2,281	0.3456	4,318	7.50	576	7.5
2015	7,222.65	3,130	2,164	0.2995	5,059	8.50	595	6.5
2016	4,120.79	1,511	1,044	0.2535	3,076	9.50	324	5.5
2017	10,923.27	3,277	2,265	0.2074	8,658	10.50	825	4.5
2018	64,553.45	15,062	10,412	0.1613	54,141	11.50	4,708	3.5
2019	15,239.53	2,540	1,756	0.1152	13,484	12.50	1,079	2.5
2020	31,354.81	3,135	2,167	0.0691	29,187	13.50	2,162	1.5
2021	2,675.45	89	62	0.0230	2,614	14.50	180	0.5
TOTAL	307,607.56	184,956	127,853		179,755		60,397	

COMPOSITE ANNUAL ACCRUAL RATE	19.63%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.42
COMPOSITE AVERAGE AGE (YEARS)	9.02
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.98

MDU Gas

Account #: 391.30 - General - Computer Equipment - PC

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	1,030.46	721	820	0.7956	211	1.50	140	3.5
2021	17,668.66	1,767	2,008	0.1137	15,660	4.50	3,480	0.5
TOTAL	18,699.12	2,488	2,828		15,871		3,620	

COMPOSITE ANNUAL ACCRUAL RATE 19.36%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.15

COMPOSITE AVERAGE AGE (YEARS) 0.67

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 4.33

MDU Gas

Account #: 392.10 - General - Transportation Equipment - Trailers

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R1
ASL: 20
Net Salvage: 10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	919.23	738	827	1.0000	0	2.15	0	33.5
1991	8,360.24	6,359	7,524	1.0000	0	3.10	0	30.5
1995	5,298.28	3,688	4,768	1.0000	0	4.53	0	26.5
1997	5,287.98	3,490	4,759	1.0000	0	5.33	0	24.5
1998	13,445.80	8,620	12,101	1.0000	0	5.75	0	23.5
2002	31,473.89	17,568	28,327	1.0000	0	7.60	0	19.5
2003	27,658.15	14,813	24,892	1.0000	0	8.10	0	18.5
2004	21,127.88	10,821	19,015	1.0000	0	8.62	0	17.5
2005	39,770.62	19,407	35,794	1.0000	0	9.16	0	16.5
2007	75,425.15	32,979	67,883	1.0000	0	10.28	0	14.5
2008	53,783.17	22,090	48,405	1.0000	0	10.87	0	13.5
2010	45,133.06	16,047	38,447	0.9465	2,173	12.10	180	11.5
2011	66,102.35	21,614	51,785	0.8705	7,707	12.73	605	10.5
2012	26,586.22	7,918	18,971	0.7929	4,957	13.38	370	9.5
2018	29,796.26	3,396	8,137	0.3034	18,680	17.47	1,069	3.5
TOTAL	450,168.28	189,548	371,635		33,516		2,224	

COMPOSITE ANNUAL ACCRUAL RATE 0.49%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.83

COMPOSITE AVERAGE AGE (YEARS) 14.25

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 10.64

MDU Gas

Account #: 392.20 - General - Transportation Equipment - Vehicles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2
ASL: 10
Net Salvage: 20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1994	6,665.89	5,066	3,835	0.7191	1,498	0.50	1,498	27.5
1995	30,400.31	22,992	17,403	0.7156	6,917	0.55	6,917	26.5
1996	1,076.97	805	609	0.7069	252	0.66	252	25.5
2000	16,395.45	11,398	8,627	0.6577	4,489	1.31	3,427	21.5
2001	22,868.12	15,557	11,775	0.6436	6,520	1.50	4,357	20.5
2002	60,123.25	39,966	30,250	0.6289	17,849	1.69	10,556	19.5
2003	123,846.92	80,314	60,789	0.6136	38,288	1.89	20,218	18.5
2004	227,288.72	143,540	108,644	0.5975	73,187	2.11	34,754	17.5
2005	90,578.36	55,594	42,078	0.5807	30,384	2.33	13,052	16.5
2006	26,670.64	15,873	12,014	0.5631	9,322	2.56	3,641	15.5
2007	50,772.32	29,235	22,128	0.5448	18,490	2.80	6,598	14.5
2008	100,964.06	56,127	42,482	0.5260	38,289	3.05	12,549	13.5
2009	139,629.38	74,826	56,635	0.5070	55,068	3.30	16,680	12.5
2010	281,152.83	145,120	109,840	0.4883	115,082	3.55	32,436	11.5
2011	374,593.47	186,138	140,886	0.4701	158,788	3.79	41,911	10.5
2012	180,318.93	86,148	65,205	0.4520	79,050	4.03	19,625	9.5
2013	305,760.51	139,892	105,883	0.4329	138,725	4.28	32,405	8.5
2014	515,664.08	223,896	169,465	0.4108	243,066	4.57	53,157	7.5
2015	1,755,572.41	711,116	538,238	0.3832	866,219	4.94	175,465	6.5
2016	1,544,833.66	567,130	429,257	0.3473	806,610	5.41	149,067	5.5
2017	1,873,055.94	595,583	450,792	0.3008	1,047,652	6.03	173,875	4.5
2018	575,076.89	148,186	112,161	0.2438	347,901	6.78	51,320	3.5
2019	1,820,835.09	346,358	262,156	0.1800	1,194,512	7.62	156,714	2.5
2020	1,689,573.50	198,426	150,187	0.1111	1,201,472	8.53	140,820	1.5
2021	1,042,480.61	41,577	31,469	0.0377	802,515	9.50	84,462	0.5

MDU Gas

Account #: 392.20 - General - Transportation Equipment - Vehicles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2
ASL: 10
Net Salvage: 20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	12,856,198.31	3,940,863	2,982,809		7,302,149		1,245,756	

COMPOSITE ANNUAL ACCRUAL RATE	9.69%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	5.32
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.17

MDU Gas

Account #: 393.00 - General - Stores Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1996	1,389.93	1,181	953	0.6859	437	4.50	97	25.5
2000	755.02	541	437	0.5782	318	8.50	37	21.5
2001	21,319.46	14,568	11,754	0.5513	9,566	9.50	1,007	20.5
2002	14,197.38	9,228	7,445	0.5244	6,752	10.50	643	19.5
2003	14,253.48	8,790	7,092	0.4975	7,162	11.50	623	18.5
2004	5,267.69	3,073	2,479	0.4706	2,789	12.50	223	17.5
2018	5,088.91	594	479	0.0941	4,610	26.50	174	3.5
2020	35,087.10	1,754	1,415	0.0403	33,672	28.50	1,181	1.5
2021	5,939.28	99	80	0.0134	5,859	29.50	199	0.5
TOTAL	103,298.25	39,829	32,134		71,164		4,184	

COMPOSITE ANNUAL ACCRUAL RATE	4.05%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	11.57
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.43

MDU Gas

Account #: 394.10 - General - Tools, Shop, & Garage Equipment - Non-Unitized

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	172,050.35	150,544	165,993	0.9648	6,057	2.50	2,423	17.5
2005	209,470.07	172,813	190,547	0.9097	18,923	3.50	5,406	16.5
2006	234,239.43	181,536	200,165	0.8545	34,074	4.50	7,572	15.5
2007	189,720.92	137,548	151,663	0.7994	38,058	5.50	6,920	14.5
2008	157,584.50	106,370	117,286	0.7443	40,299	6.50	6,200	13.5
2009	72,922.59	45,577	50,254	0.6891	22,669	7.50	3,023	12.5
2010	172,074.59	98,943	109,097	0.6340	62,978	8.50	7,409	11.5
2011	157,395.97	82,633	91,113	0.5789	66,283	9.50	6,977	10.5
2012	158,798.39	75,429	83,170	0.5237	75,628	10.50	7,203	9.5
2013	351,862.77	149,542	164,888	0.4686	186,975	11.50	16,259	8.5
2014	264,155.89	99,058	109,224	0.4135	154,932	12.50	12,395	7.5
2015	274,487.44	89,208	98,363	0.3584	176,124	13.50	13,046	6.5
2016	576,092.53	158,425	174,684	0.3032	401,409	14.50	27,683	5.5
2017	795,502.28	178,988	197,356	0.2481	598,146	15.50	38,590	4.5
2018	711,086.42	124,440	137,211	0.1930	573,876	16.50	34,780	3.5
2019	527,577.86	65,947	72,715	0.1378	454,863	17.50	25,992	2.5
2020	685,399.59	51,405	56,680	0.0827	628,719	18.50	33,985	1.5
2021	2,149,400.32	53,735	59,249	0.0276	2,090,151	19.50	107,187	0.5
TOTAL	7,859,821.91	2,022,141	2,229,659		5,630,163		363,050	

COMPOSITE ANNUAL ACCRUAL RATE	4.62%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.28
COMPOSITE AVERAGE AGE (YEARS)	5.15
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.85

MDU Gas

Account #: 394.30 - General - Vehicle Maintenance Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2006	5,923.44	4,591	4,598	0.7762	1,325	4.50	295	15.5
2007	30,449.83	22,076	22,109	0.7261	8,340	5.50	1,516	14.5
TOTAL	36,373.27	26,667	26,707		9,666		1,811	

COMPOSITE ANNUAL ACCRUAL RATE	4.98%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.73
COMPOSITE AVERAGE AGE (YEARS)	14.66
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.34

MDU Gas

Account #: 395.00 - General - Laboratory Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life

Survivor Curve: SQ

ASL: 20

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	53,124.91	51,797	26,462	0.4981	26,663	0.50	26,663	19.5
2009	59,556.79	37,223	19,017	0.3193	40,540	7.50	5,405	12.5
2013	3,826.75	1,626	831	0.2171	2,996	11.50	261	8.5
2014	25,534.24	9,575	4,892	0.1916	20,642	12.50	1,651	7.5
2018	33,267.14	5,822	2,974	0.0894	30,293	16.50	1,836	3.5
2019	54,739.64	6,842	3,496	0.0639	51,244	17.50	2,928	2.5
2020	32,924.30	2,469	1,262	0.0383	31,663	18.50	1,712	1.5
2021	53,812.00	1,345	687	0.0128	53,125	19.50	2,724	0.5
TOTAL	316,785.77	116,700	59,620		257,166		43,180	

COMPOSITE ANNUAL ACCRUAL RATE	13.63%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.19
COMPOSITE AVERAGE AGE (YEARS)	7.37
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.63

MDU Gas

Account #: 396.10 - General - Trailers - Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2
ASL: 25
Net Salvage: 30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1984	1,685.39	866	1,180	1.0000	0	6.65	0	37.5
1993	2,788.91	1,258	1,952	1.0000	0	8.89	0	28.5
1994	29,115.83	12,933	20,381	1.0000	0	9.14	0	27.5
1997	3,534.95	1,499	2,474	1.0000	0	9.86	0	24.5
1998	7,213.88	3,010	5,050	1.0000	0	10.10	0	23.5
1999	57,054.45	23,408	39,938	1.0000	0	10.35	0	22.5
2001	14,107.86	5,578	9,876	1.0000	0	10.88	0	20.5
2002	17,670.84	6,843	12,370	1.0000	0	11.17	0	19.5
2003	5,063.98	1,916	3,545	1.0000	0	11.49	0	18.5
2004	27,881.96	10,278	19,517	1.0000	0	11.83	0	17.5
2005	9,365.26	3,352	6,556	1.0000	0	12.22	0	16.5
2006	28,677.96	9,921	20,075	1.0000	0	12.65	0	15.5
2007	21,445.76	7,133	15,012	1.0000	0	13.12	0	14.5
2008	19,890.76	6,321	13,924	1.0000	0	13.65	0	13.5
2010	31,042.83	8,793	21,730	1.0000	0	14.88	0	11.5
2011	55,363.27	14,589	37,913	0.9783	841	15.59	54	10.5
2012	34,907.25	8,458	21,980	0.8995	2,455	16.35	150	9.5
2013	68,079.28	14,971	38,905	0.8164	8,751	17.15	510	8.5
2014	156,419.16	30,757	79,928	0.7300	29,566	17.98	1,645	7.5
2015	20,702.99	3,574	9,288	0.6409	5,204	18.83	276	6.5
2016	229,234.62	33,901	88,097	0.5490	72,368	19.72	3,670	5.5
2017	68,558.94	8,391	21,805	0.4544	26,186	20.63	1,269	4.5
2018	143,287.11	13,780	35,809	0.3570	64,492	21.57	2,991	3.5
2019	58,618.83	4,061	10,553	0.2572	30,480	22.53	1,353	2.5
2020	141,293.68	5,910	15,358	0.1553	83,547	23.51	3,554	1.5
2021	53,135.76	743	1,932	0.0519	35,263	24.50	1,439	0.5

MDU Gas

Account #: 396.10 - General - Trailers - Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2
ASL: 25
Net Salvage: 30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	1,306,141.51	242,246	555,146		359,153		16,911	

COMPOSITE ANNUAL ACCRUAL RATE	1.29%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.43
COMPOSITE AVERAGE AGE (YEARS)	8.03
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.38

MDU Gas

Account #: 396.20 - General - Power Operated Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L1
ASL: 3
Net Salvage: 85%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1995	2,696.46	404	-1,219	-3.0134	1,623		1,623	27.5
1999	753.59	113	-341	-3.0134	454		454	23.5
2000	66,368.27	9,955	-29,999	-3.0134	39,954		39,954	22.5
2002	84,776.40	12,716	-38,320	-3.0134	51,036		51,036	20.5
2003	130,365.37	19,555	-58,927	-3.0134	78,481		78,481	19.5
2004	44,828.72	6,724	-20,263	-3.0134	26,987		26,987	18.5
2005	193,813.70	29,072	-87,606	-3.0134	116,678		116,678	17.5
2006	118,679.47	17,802	-53,644	-3.0134	71,446		71,446	16.5
2007	244,145.52	36,622	-110,357	-3.0134	146,978		146,978	15.5
2008	118,600.33	17,790	-53,609	-3.0134	71,399		71,399	14.5
2010	78,497.44	11,775	-35,482	-3.0134	47,256		47,256	12.5
2011	228,311.70	34,247	-103,199	-3.0134	137,446		137,446	11.5
2012	349,796.46	52,469	-158,112	-3.0134	210,581		210,581	10.5
2013	173,033.41	21,629	-65,178	-2.5112	91,133	0.50	91,133	8.5
2014	436,810.84	53,662	-161,707	-2.4680	227,228	0.54	227,228	7.5
2015	279,736.03	32,645	-98,373	-2.3444	140,334	0.67	140,334	6.5
2016	893,003.87	96,571	-291,009	-2.1725	424,959	0.84	424,959	5.5
2017	482,637.34	47,106	-141,950	-1.9608	214,346	1.05	204,535	4.5
2018	580,791.23	49,342	-148,686	-1.7067	235,805	1.30	181,265	3.5
2019	457,831.79	31,947	-96,269	-1.4018	164,944	1.60	102,806	2.5
2020	585,314.24	30,032	-90,499	-1.0308	178,296	1.97	90,331	1.5
2021	3,489,761.83	75,660	-227,996	-0.4356	751,460	2.57	292,809	0.5

MDU Gas

Account #: 396.20 - General - Power Operated Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L1
ASL: 3
Net Salvage: 85%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	9,040,554.01	687,840	-2,072,744		3,428,827		2,755,719	

COMPOSITE ANNUAL ACCRUAL RATE	30.48%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	-0.23
COMPOSITE AVERAGE AGE (YEARS)	4.90
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	1.48

MDU Gas

Account #: 397.10 - General - Comm. Equip. - Fixed Radios

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	25,677.39	24,821	23,288	0.9069	2,390	0.50	2,390	14.5
2009	230,835.87	192,363	180,477	0.7818	50,359	2.50	20,144	12.5
2010	60,049.13	46,038	43,193	0.7193	16,856	3.50	4,816	11.5
2011	38,559.26	26,991	25,324	0.6567	13,236	4.50	2,941	10.5
2013	351,331.96	199,088	186,786	0.5317	164,546	6.50	25,315	8.5
2014	180,810.68	90,405	84,819	0.4691	95,992	7.50	12,799	7.5
2015	67,172.78	29,108	27,310	0.4066	39,863	8.50	4,690	6.5
2016	71,933.82	26,376	24,746	0.3440	47,188	9.50	4,967	5.5
2017	45,623.70	13,687	12,841	0.2815	32,782	10.50	3,122	4.5
2018	15,760.98	3,678	3,450	0.2189	12,311	11.50	1,070	3.5
2020	76,666.80	7,667	7,193	0.0938	69,474	13.50	5,146	1.5
2021	26,121.94	871	817	0.0313	25,305	14.50	1,745	0.5
TOTAL	1,190,544.31	661,093	620,243		570,301		89,145	

COMPOSITE ANNUAL ACCRUAL RATE	7.49%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	8.33
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.67

MDU Gas

Account #: 397.20 - General - Comm. Equip. - Mobile Radios

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2008	98,031.63	88,228	84,721	0.8642	13,311	1.50	8,874	13.5
2009	164,946.06	137,455	131,990	0.8002	32,956	2.50	13,182	12.5
2010	45,022.41	34,517	33,145	0.7362	11,878	3.50	3,394	11.5
2011	2,138.33	1,497	1,437	0.6722	701	4.50	156	10.5
2012	21,603.54	13,682	13,138	0.6082	8,465	5.50	1,539	9.5
2013	19,539.26	11,072	10,632	0.5441	8,907	6.50	1,370	8.5
2014	18,424.79	9,212	8,846	0.4801	9,579	7.50	1,277	7.5
2015	51,534.27	22,332	21,444	0.4161	30,091	8.50	3,540	6.5
2016	26,099.70	9,570	9,189	0.3521	16,910	9.50	1,780	5.5
2017	8,182.69	2,455	2,357	0.2881	5,825	10.50	555	4.5
2018	5,832.33	1,361	1,307	0.2241	4,526	11.50	394	3.5
TOTAL	461,355.01	331,382	318,207		143,148		36,061	

COMPOSITE ANNUAL ACCRUAL RATE	7.82%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	10.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.23

MDU Gas

Account #: 397.30 - General Telephone Communication Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life

Survivor Curve: SQ

ASL: 10

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	2,295.23	1,951	1,403	0.6113	892	1.50	595	8.5
2016	22,189.34	12,204	8,777	0.3955	13,413	4.50	2,981	5.5
2017	101,395.61	45,628	32,813	0.3236	68,582	5.50	12,470	4.5
2020	2,578.64	387	278	0.1079	2,300	8.50	271	1.5
TOTAL	128,458.82	60,170	43,271		85,188		16,317	

COMPOSITE ANNUAL ACCRUAL RATE	12.70%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.34
COMPOSITE AVERAGE AGE (YEARS)	4.68
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.32

MDU Gas

Account #: 397.80 - Network Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life

Survivor Curve: SQ

ASL: 5

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	9,063.76	6,345	4,836	0.5336	4,227	1.50	2,818	3.5
2020	20,001.23	6,000	4,574	0.2287	15,427	3.50	4,408	1.5
2021	11,240.90	1,124	857	0.0762	10,384	4.50	2,308	0.5
TOTAL	40,305.89	13,469	10,267		30,039		9,534	

COMPOSITE ANNUAL ACCRUAL RATE	23.65%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	1.67
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	3.33

MDU Gas

Account #: 398.00 - Miscellaneous Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	2,240.64	1,748	2,241	1.0000	0	5.50	0	19.5
2003	541.85	401	542	1.0000	0	6.50	0	18.5
2005	790.03	521	790	1.0000	0	8.50	0	16.5
2006	11,912.45	7,386	11,912	1.0000	0	9.50	0	15.5
2007	2,964.83	1,720	2,965	1.0000	0	10.50	0	14.5
2008	10,585.40	5,716	10,585	1.0000	0	11.50	0	13.5
2011	2,281.70	958	-4,442	-1.9468	6,724	14.50	464	10.5
2012	1,969.43	748	-6,628	-3.3652	8,597	15.50	555	9.5
2013	13,207.22	4,490	-67,342	-5.0988	80,549	16.50	4,882	8.5
2017	4,061.42	731	4,061	1.0000	0	20.50	0	4.5
2018	9,478.36	1,327	9,478	1.0000	0	21.50	0	3.5
2020	8,595.27	516	8,595	1.0000	0	23.50	0	1.5
2021	3,076.06	62	376	0.1224	2,700	24.50	110	0.5
TOTAL	71,704.66	26,324	-26,865		98,569		6,011	

COMPOSITE ANNUAL ACCRUAL RATE	8.38%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	-0.37
COMPOSITE AVERAGE AGE (YEARS)	9.18
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.82

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[3]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

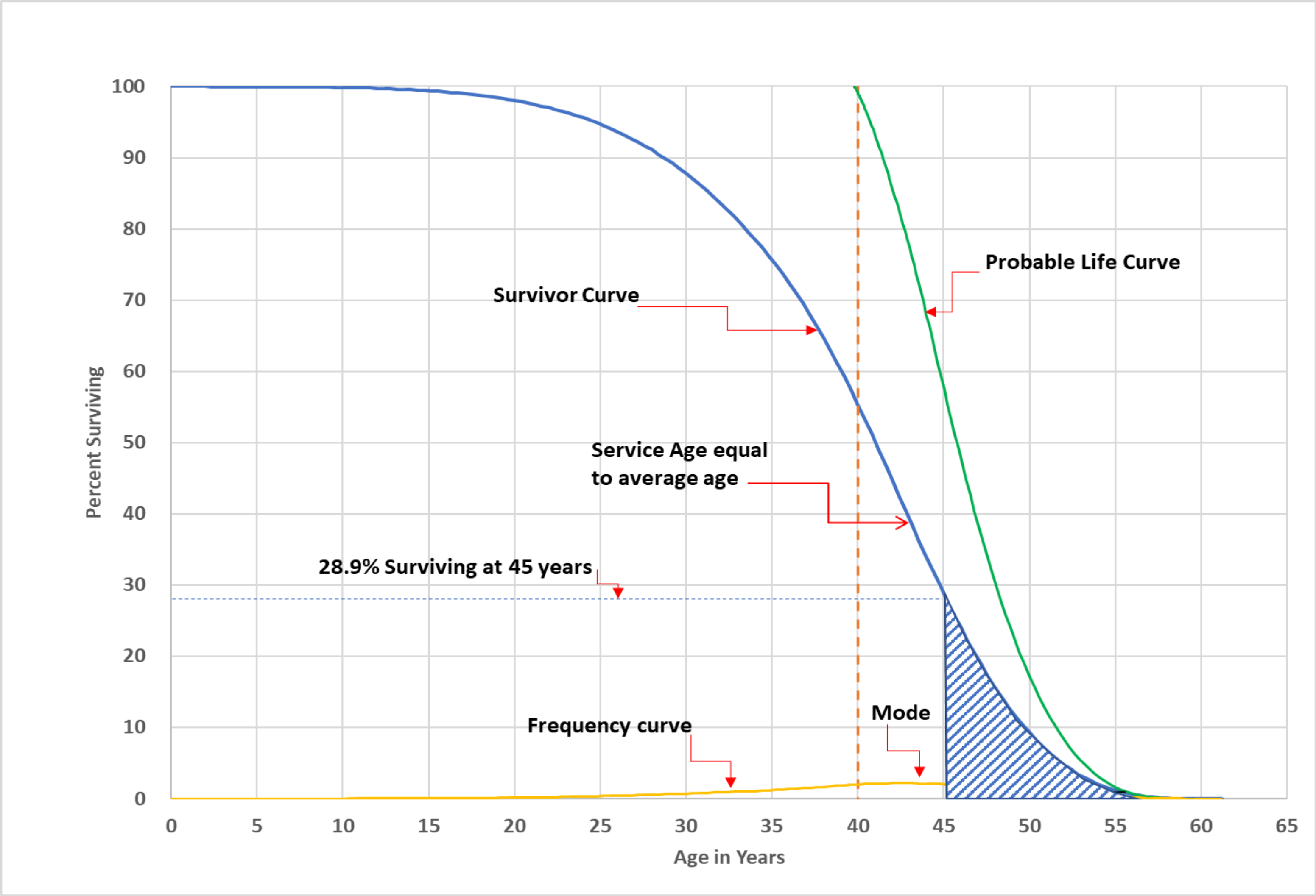
9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age"[4]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[5] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[6]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[3] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[4] *Ibid*, 23.
[5] *Ibid*, 29.
[6] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[7]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[8]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[9] presenting his development of the fourth family consisting of the four O-type survivor curves.

---

[7] *Ibid*, 21

[8] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[9] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

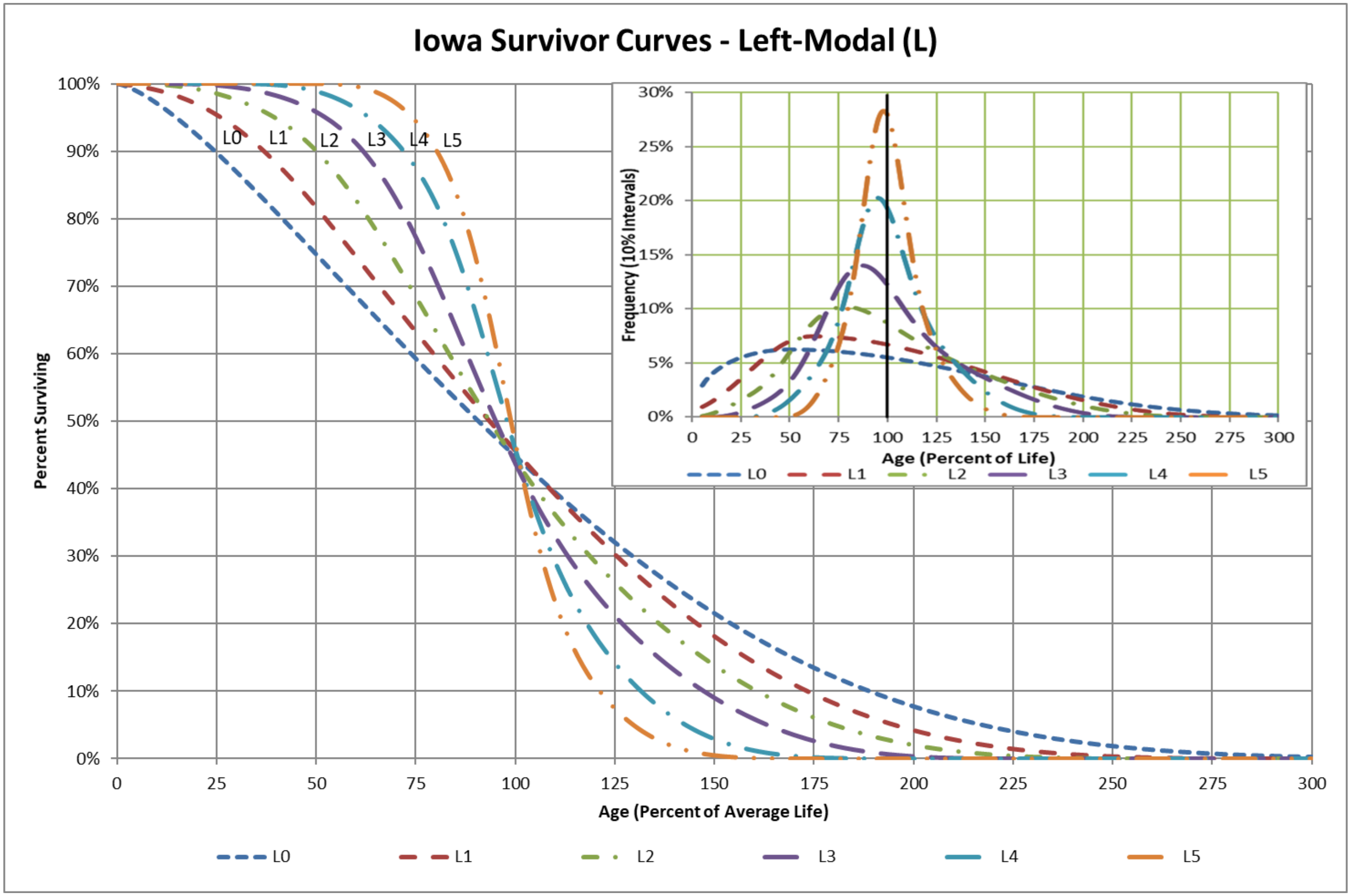


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

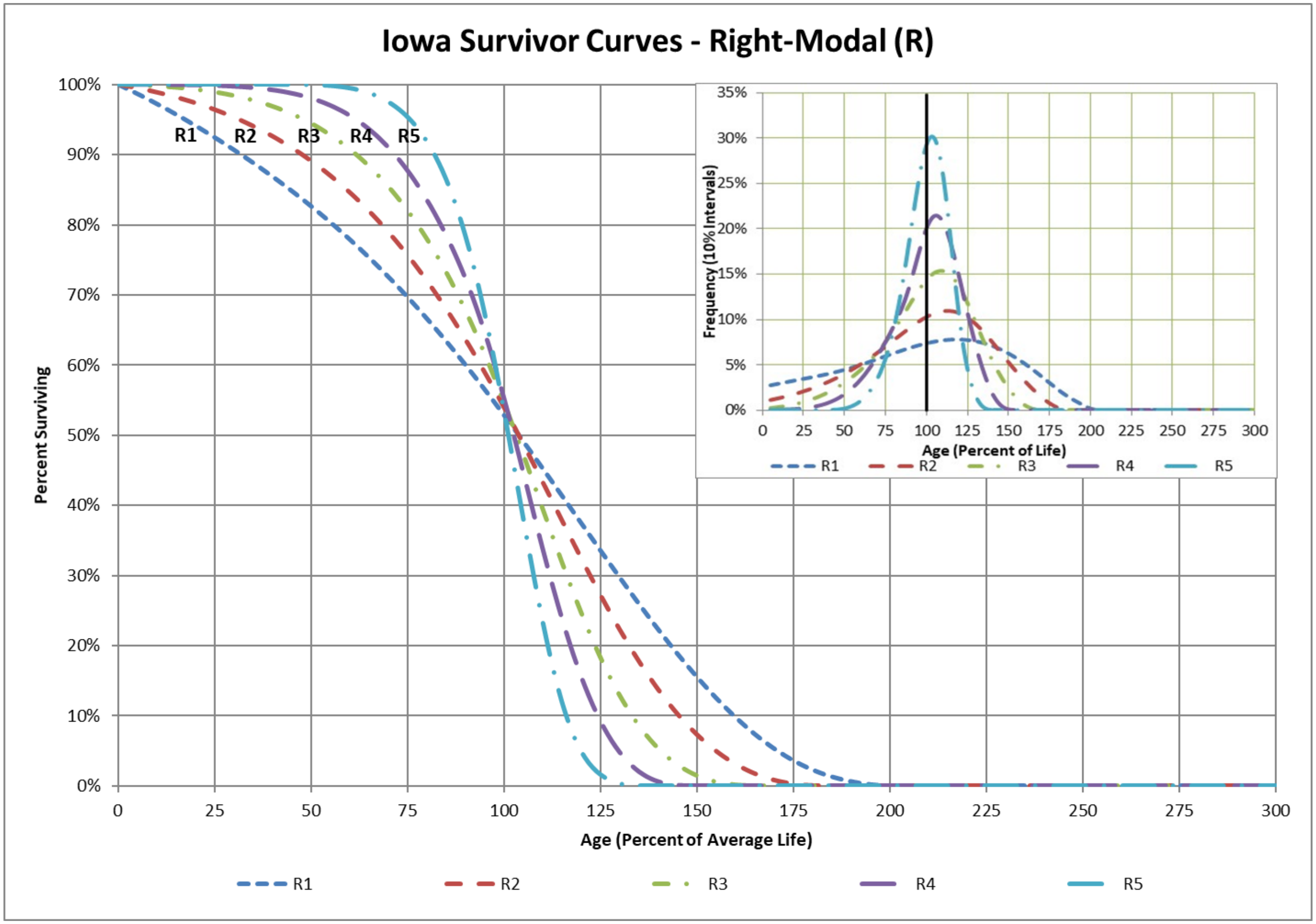


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

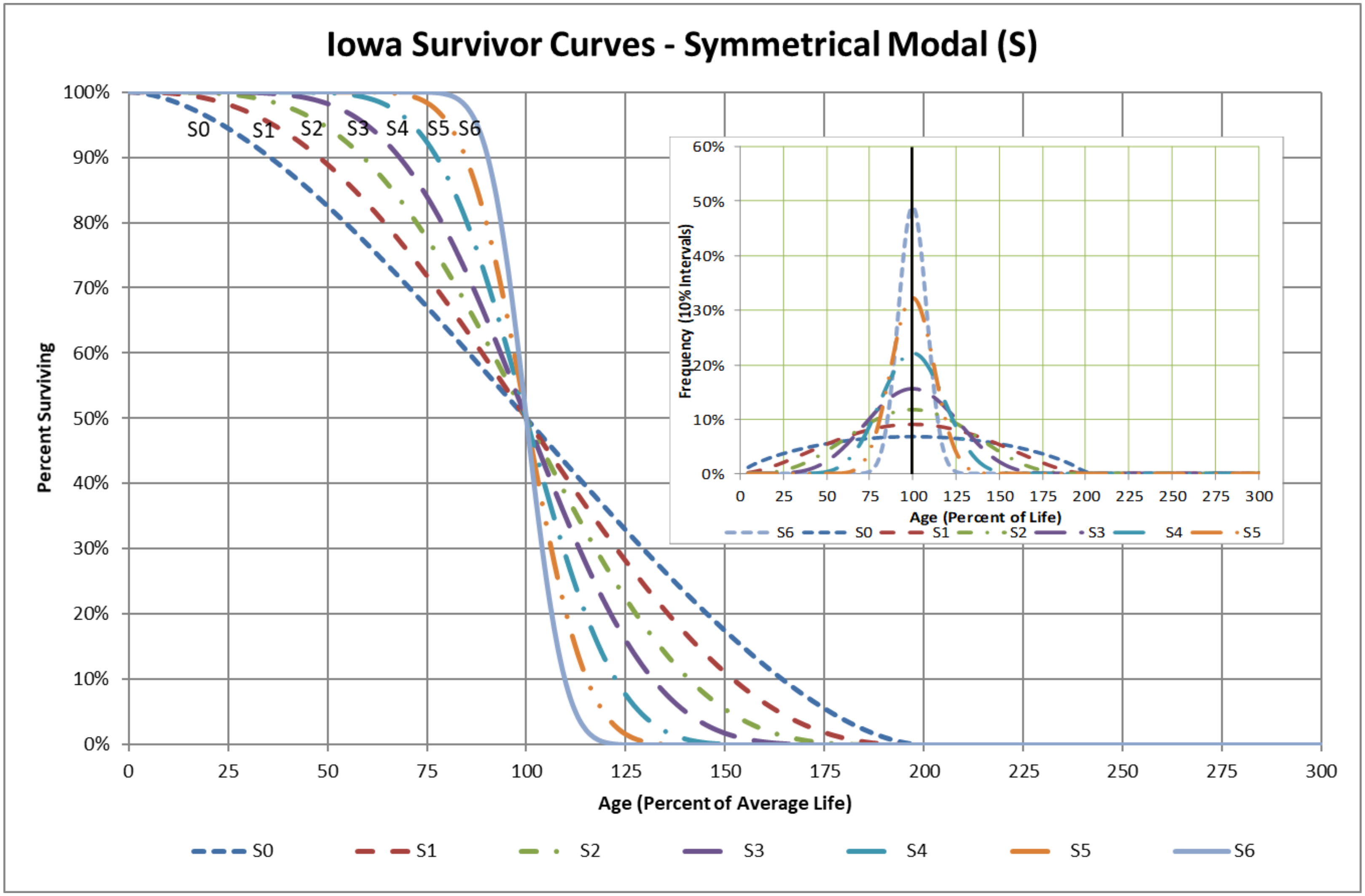
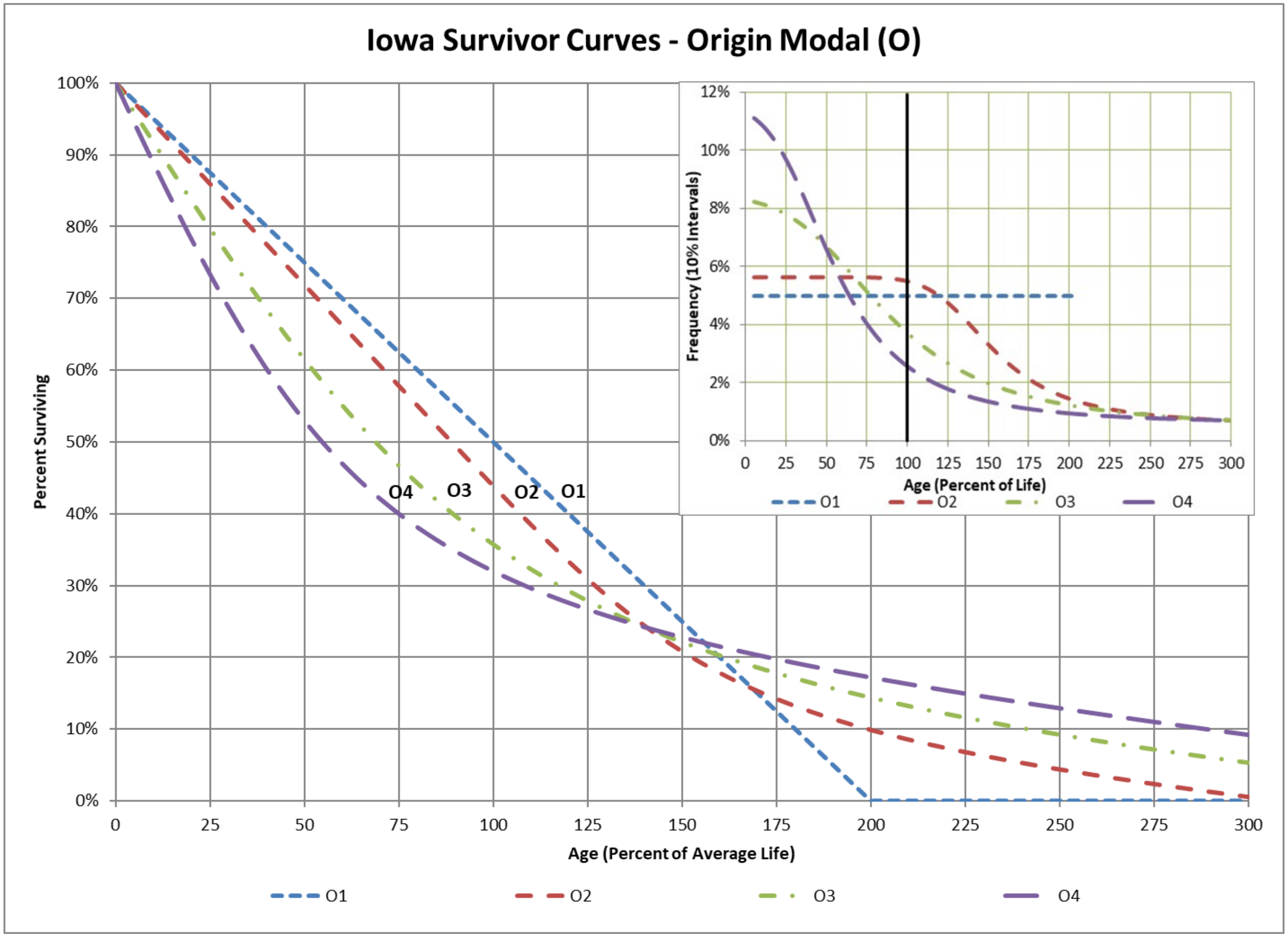


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[10] Engineering Valuation and Depreciation[11] and Depreciation Systems[12].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[10] Anson, Winfrey & Hempstead, supra note 7

[11] Anson, Winfrey & Hempstead, supra note 7

[12] Wolf & Fitch, supra note 2

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					**Placement Band 2003-2017**
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

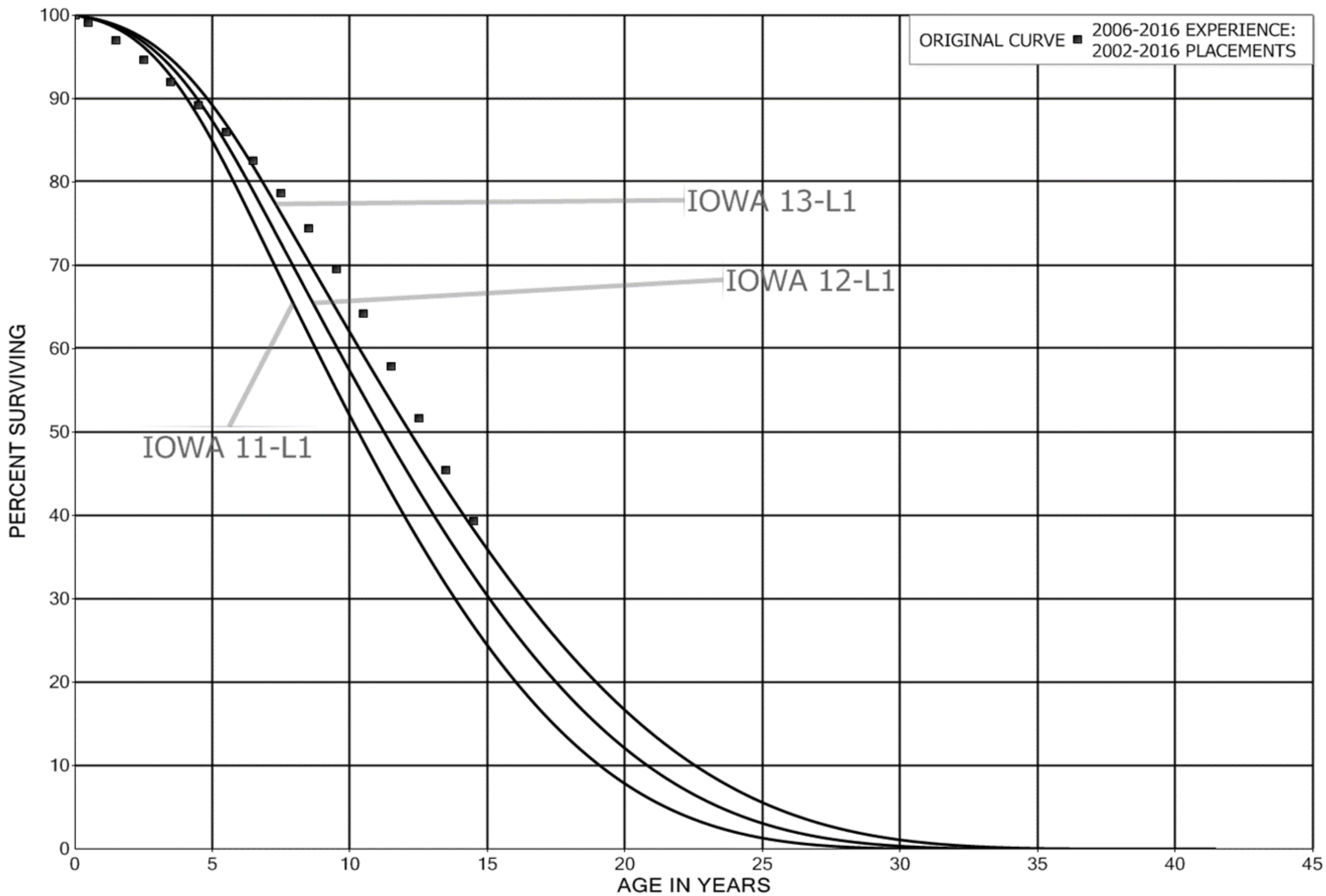


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

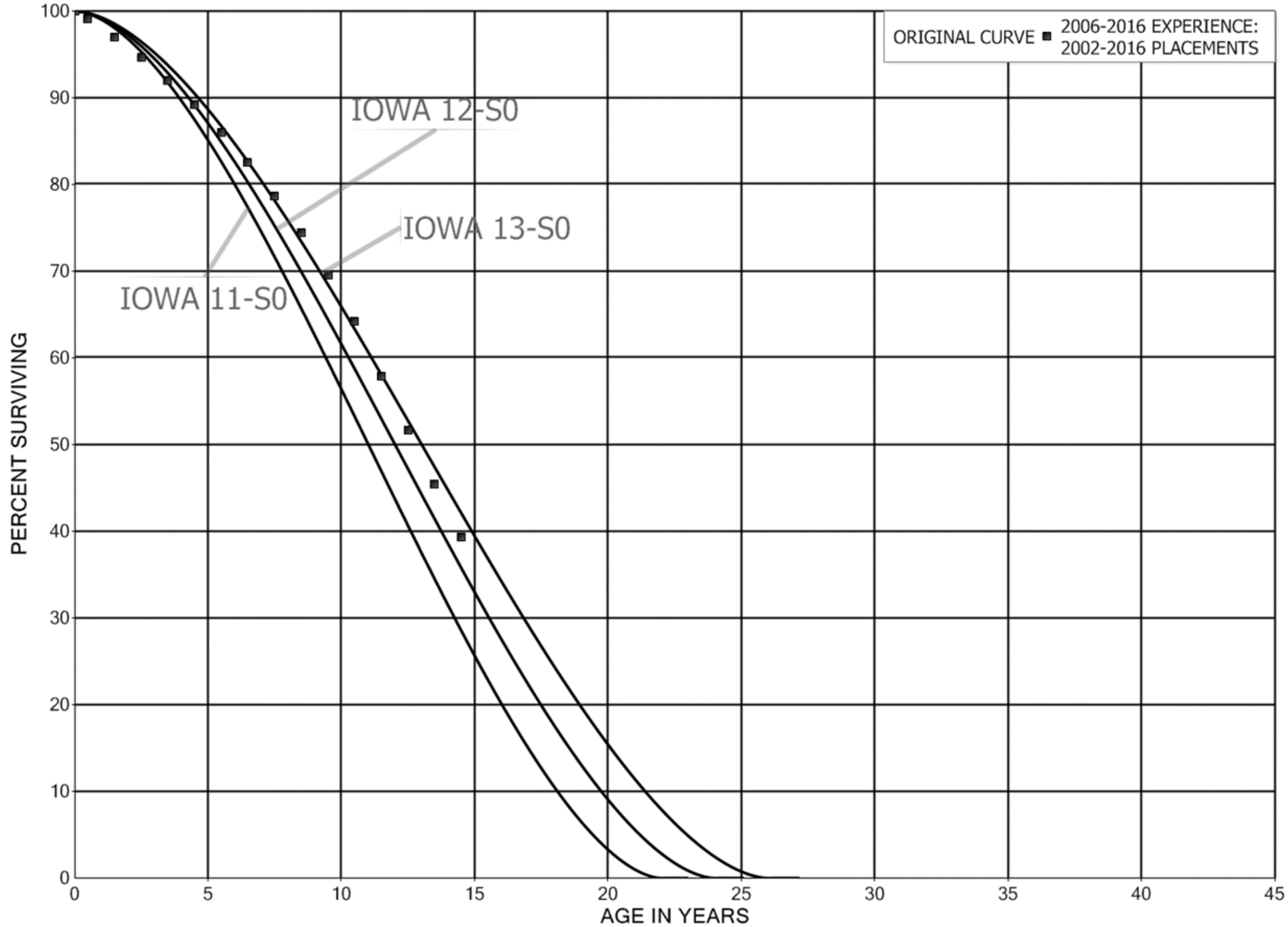


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

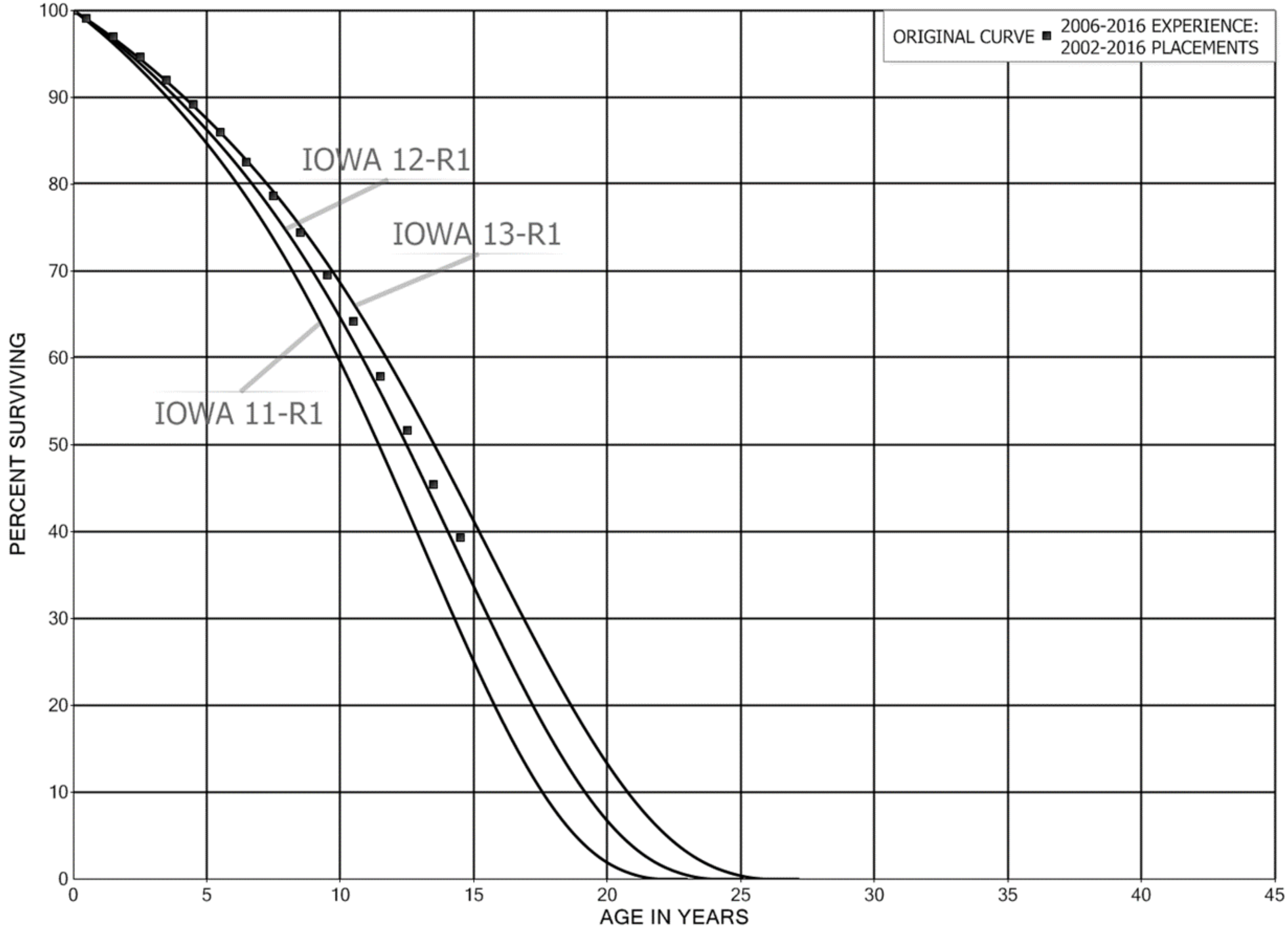
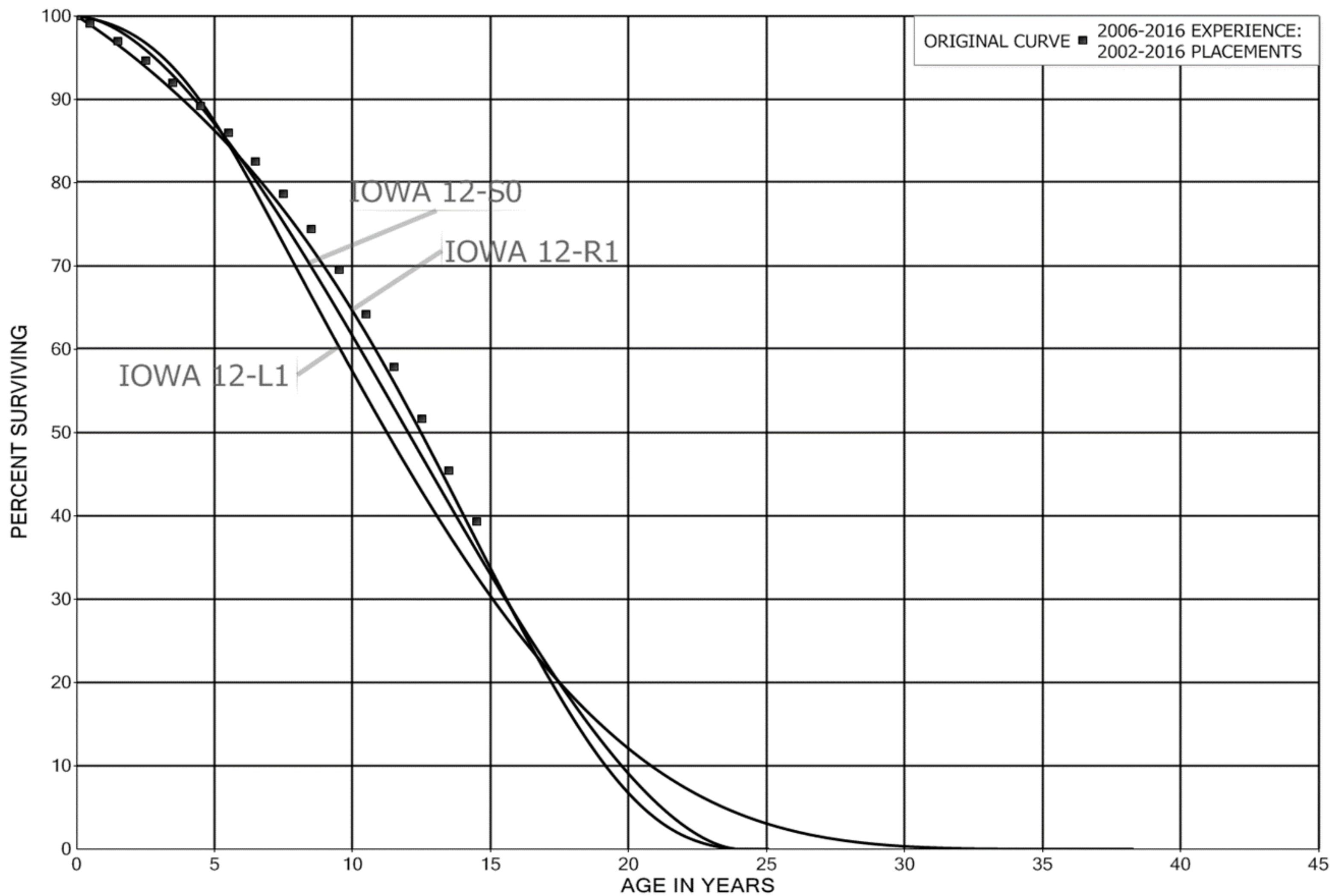


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to Canadian peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account. Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated are usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to Canadian peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and Canadian peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

Exhibit No.___(LEK-4)
Common Report

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO COMMON PLANT IN SERVICE
as of December 31, 2021

Prepared for Montana-Dakota Utilities Co.
April 2023

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
587.997.6489

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to Montana-Dakota Utilities Co.'s ("MDU" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the common general plant accounts, as of December 31, 2021. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of common utility plant, as of December 31, 2021.

The depreciation rates are based on the broad group Straight-Line method using the Average Life Group ("ALG") procedure and were applied on a Remaining Life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2021, are amortized over the composite remaining life of assets.

MDU's accounting policy has not changed since the last depreciation study.

Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to common plant in service, as of December 31, 2021. The annual depreciation accrual rates are summarized by tables related to:

- the total required annual accrual amounts;
- the annual accrual requirements related to the recovery of the original cost of the investment; and
- the annual accrual amount related to the recovery of the expected net salvage requirements at the time of retirement.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $4.3 million, when applied to depreciable plant study balances, as of December 31, 2021, of $81.5 million. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group / Accounts	Original Cost	Previous Study Annual Accrual		Recommended Annual Accrual	
General Plant	$81,481,558	4.30%	$2,924,572	5.31%	$4,327,970
TOTAL	**$81,481,558**	**4.30%**	**$2,924,572**	**5.31%**	**$4,327,970**

Total Depreciable Plant

81.48M

Previous Study Annual Accrual

2.92M

Proposed 2022 Depreciation Expense Accrual

4.33M

Previous Study Depreciation Rate

4.30%

Proposed 2022 Depreciation Rate

5.31%

Change in Annual Accrual

1.40M

Change in Depreciation Rate

1.01%

SECTION 2

2 BASIS OF THE STUDY

2.1 Scope

This study sets forth the results of the depreciation study for the common general plant assets of MDU, to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of investment as of December 31, 2021. The rates and amounts are based on the Straight-Line Method, incorporating the ALG Procedure applied on a Remaining Life Basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the MDU assets in service, as of December 31, 2021.

The service life estimates resulting from the study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data recorded through December 31, 2021;
- a review of MDU company practice and outlook, as they relate to plant operation and retirement; and
- consideration of current practice in the electric and gas system industries, including knowledge of service life estimates used for other electric and gas system companies.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The estimated survivor curves used in this study are based on studies incorporating actual data through 2021 for most accounts.

2.2 Plan of Study

This study is presented in the following order:

Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the basis of the study
Section 3:	Development of the Required Depreciation Rates, presents descriptions of the methods used and factors considered in the service life study
Section 4:	Calculation of Annual and Accrued Depreciation, presents the methods and procedures used in the calculation of depreciation
Section 5:	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, and 1B.
Section 6:	Presents the results of the Retirement Rate Analysis
Section 7:	Presents the results of the Net Salvage Study
Section 8:	Presents the results of the Detailed Depreciation Calculations
Section 9:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10:	Estimation of Net Salvage discusses the methodology used in calculating net salvages

2.3 Depreciation

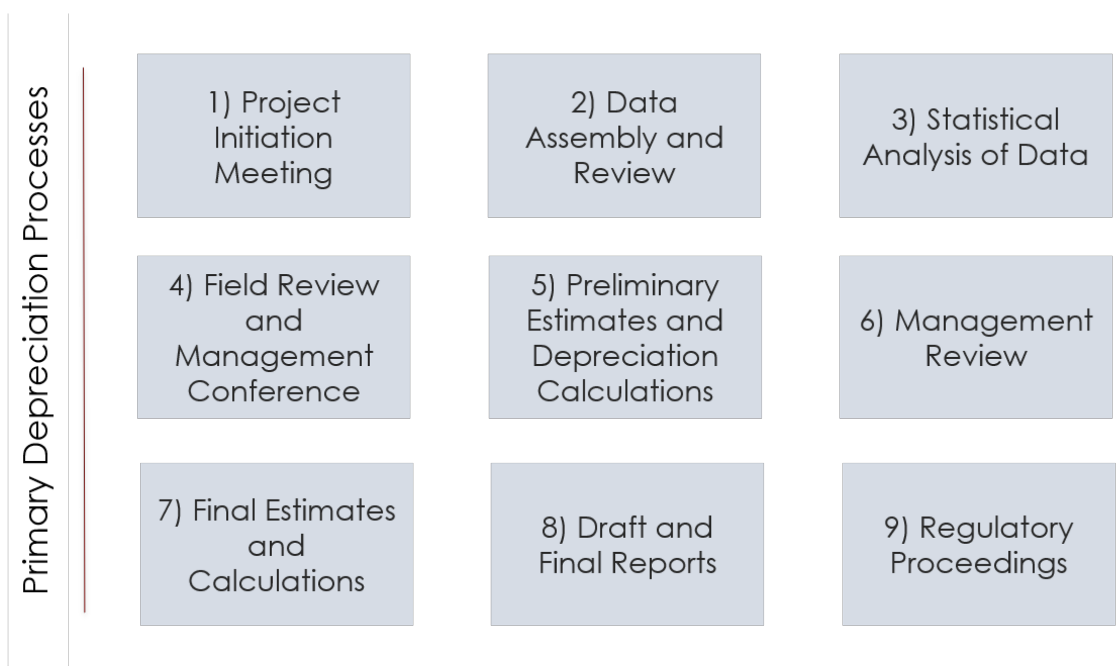
A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. selection of an appropriate grouping procedure;
4. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
5. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

Consistent with the current MDU practice, amortization accounting continues to be recommended for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.



2.4 Information Provided by MDU

MDU has provided Concentric with the required information, as of December 31, 2021 for all accounts being studied in this study. This information includes the following:

- Current balances by vintage year for each account (aged balances) through December 31, 2021. The balances provide the amount of investment sorted by installation year. This file is only inclusive of plant in service and does not include any retirement information;
- retirement transactions for all accounts through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired; and
- cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage through December 31, 2021. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.5 Data Reconciliation

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;
- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that any adjusting transactions are properly accounted for within the databases.

SECTION 3

3 DEVELOPMENT OF THE REQUIRED DEPRECIATION RATES

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e. Iowa curve) and net salvage recommendations (i.e. the depreciation parameters). Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for MDU have been calculated in accordance with the Straight-Line method, the ALG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of common plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature.

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Gas Utilities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service - that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.1.1 Study Depreciation Methods and Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group (ALG) and Equal Life Group (ELG) procedures.

In the ALG Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

While the Equal Life Group Procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Straight-Line Method, Average Life Group Procedure is a commonly used depreciation calculation that has been widely accepted in jurisdictions throughout North America including MDU in prior studies. Concentric recommends its continued use.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and ALG Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account within the remaining life calculations.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to correct the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.1.2 Changes Since Last MDU Full Depreciation Study

The depreciation rates calculated in this study were calculated on the same manner as used in the prior full depreciation study – i.e. using the straight-line method, the ALG Procedure applied on a remaining life basis. However, Concentric notes that in the application of the remaining life basis, the prior study calculated the remaining life on a broad average basis, whereas Concentric incorporates a refinement into the remaining life calculations based on a weighted investment by vintage approach. The vintaged remaining life approach weighs the calculations of remaining life on an allocation of the actual book accumulated depreciation account by the Calculated Accumulated Depreciation (CAD) factor determined for each vintage of plant in service. This method is described as a CAD weighted calculation in the textbook Depreciation Systems by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994 under the title "Adjustments" within the Broad Group Model.

In contrast, the remaining life calculations in prior studies was based on a broad averaging of the composite remaining life. The method is also discussed as the Amortization Method (AM) in Depreciation Systems under the title "Adjustments" within the Broad Group Model.

When depreciation rates are calculated utilizing a remaining life technique, the depreciation rate is established by dividing the undepreciated value of each group of assets (after consideration to the net salvage requirements) by the composite remaining life of the group of assets. This calculation is made for each vintage surviving investment as of the date of the study (December 31, 2021), and then composited into a calculation for the account or group as a whole. This calculation requires two estimates:

1. The actual booked accumulated depreciation for each vintage within each account.

   MDU does not track the booked accumulated depreciation reserve by vintage within each account. Rather the depreciation expense is calculated at an account level and booked to accumulated depreciation at the same account level. Concentric notes that this is the practice employed by virtually all regulated utilities. As such, the accumulated depreciation by account is allocated within the account to each vintage, on the basis of the calculated accumulated depreciation by vintage. The calculated accumulated depreciation is a function of the estimated survivor curve, the average service life estimate, the net salvage estimates and the achieved age of each vintage.

2. The estimated remaining life of each vintage with each account. The estimated remaining life of each vintage is a direct function of the achieved age of each vintage, the estimated survivor curve and the average service life estimate.

Once the above two estimates are determined (the allocated booked reserve by vintage and the average remaining life of each vintage), an annual accrual requirement for each vintage is determined by dividing the net book value for each vintage (considering the estimated future salvage requirements) by the average remaining life of the vintage. The annual requirement for each vintage is summed at the account level and divided into the sum of the accounts original cost surviving as of December 31, 2021.

This process results in each vintage's calculated net book value to be depreciated over an appropriate remaining life. This vintage weighting on CAD approach to the remaining life calculations is widely considered to be the most accurate. Concentric agrees and views this methodology as the correct and most appropriate calculation.

3.1.3 Survivor Curves

The use of an average service life or a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

3.1.4 Survivor Curve and Net Salvage Judgments

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric and gas utility industries, and comparisons of the service life and net salvage estimates from Concentric's studies of other utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based mostly in part on historical data related to actual retirement activity for the years 1968 through 2021, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Concentric notes the data from the previous depreciation consultant was used and considered in the historic net salvage analysis, but more relevancy was placed on the more recent data from 2009 through 2021 provided directly to Concentric by MDU. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 390 – STRUCTURES AND IMPROVEMENTS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$57,959,115	71.13%	38-R3	40-R2	0%	-5%

The investment in Structures and Improvements is approximately $57.9 million, representing 71 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1952 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $7,806,923.44 were recorded for this period. The currently approved life parameter is an Iowa 38-R3 that produced a fit with a related residual measure of 3.0467. An Iowa 40-R2 produced a better fit with a residual measure of 2.5362, as depicted on page 6-2. Discussions with MDU operational and management staff indicated that the Iowa 40-R2 is a good representation of the historical life and future expectations. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 40-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 40-R2 to represent the future expectations for the investment in this account.

This account currently has a previously approved net salvage of zero percent. This account has shown a wide range in historical net salvage activity since 1968. The range has been from negative 31 percent to positive 43 percent. A three-year band produces results that range from over negative 1,000 percent to over positive 100 percent. The five-year band ranges from over negative 500 to over positive 1,000 percent. The full depth band averages positive 21 percent. At this time, Concentric recommends that a slight step down to a negative five percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 392.1- TRANSPORTATION EQUIPMENT – TRAILERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$18,482	0.02%	25-L1	25-R1	20%	15%

The investment in this account relates to Transportation Equipment - Trailers. The investment in this account is approximately $18 thousand, representing 0.02 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1937 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $55,565.59 were recorded for this period. The currently approved life parameter is an Iowa 25-L1 which produced a fit with a related residual measure of 1.748. An Iowa 25-R1 produced a fit with a related residual measure of 1.7738, as depicted on page 6-6. Discussions with MDU operational and management staff indicated that the Iowa 25-R1 is a good representation of the historical life and future expectations. Based on the above and considerations, and on Concentric's experience, an Iowa 25-R1 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 25-R1 to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 20 percent. This account has shown a limited range in the historical net salvage activity with low retirements since 2013. At this time, Concentric recommends that a positive 15 percent net salvage estimate be used in the depreciation calculations within this study.

ACCOUNT 392.2 – TRANSPORTATION EQUIPMENT – VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curve	Previously Approved Salvage	Concentric Recommended Salvage
$8,552,949	10.5%	9-R3	10-L2.5	20%	20%

The investment in this account relates to Transportation Equipment – Vehicles. This includes everything from ¼ ton trucks to ¾ ton trucks, service trucks, and trucks with cranes.

The investment in Transportation Equipment - Vehicles is approximately $8.5 million, representing 10.5 percent of the total depreciable plant studied. The retirements, additions and other plant transactions, for the period 1979 through 2021, were analyzed by the retirement rate method. Retirements, for the period 2009 through 2021, of $7,601,423.76 were recorded for this period. The currently approved life parameter for the MDU account is an Iowa 9-R3 that produced a fit with a related residual measure of 0.2624. Data analysis and discussion with MDU personnel indicated that a slight adjustment to a 10-L2.5, with a residual measure of 0.1571, produced a better visual and mathematical fit, and is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L2.5 going forward to represent the future expectations for the investment in this account.

This account currently has an approved net salvage of positive 20 percent. This account has shown a close range in historical net salvage activity since 2009. The range has been from positive 31 percent to positive 82 percent. A three-year band produces results that range from positive 15 percent to positive 49 percent. The five-year band ranges from positive 18 percent to positive 68 percent. The full depth band averages positive 31 percent. At this time, Concentric recommends that a positive 20 percent net salvage estimate continue to be used in the depreciation calculations within this study.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable plant in service. The accounts and their amortization periods are as follows:

Account	Title	Investment	Recommended Amortization Period in Years
391.1	Office Furniture & Equipment	$2,130,096	15
391.3	Computer Equipment – PC	$3,638,802	5
391.5	Computer Equipment – Other	$2,045,305	5
393.0	Stores Equipment	$174,519	30
394.1	Tools, Shop, & Garage Equipment	$759,520	20
394.3	Vehicle Maintenance Equipment	$46,590	20
394.4	Vehicle Refueling Equipment	$3,815	20
397.1	Communication Equipment – Fixed Radios	$2,454,294	15
397.2	Communication Equipment – Mobile Radios	$1,069,272	15
397.3	General Telephone Communication Equipment	$681,544	10
397.5	Supervisory & Telemetering Equipment	$15,704	10
397.8	Network Equipment	$387,937	5
398.0	Miscellaneous Equipment	$1,543,614	25

For the purpose of calculating annual amortization amounts, as of December 31, 2021, the book depreciation reserve for each plant account (or sub-account) is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

4.2 Monitoring of Book Accumulated Depreciation

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual vintage remaining lives.

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study and are shown in Tables 1, 1A, and 1B, related to investment as of December 31, 2021. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the ALG procedure, based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The following tables provide summaries by account of the original cost of investment, calculated and booked accumulated depreciation amounts, the required amount of annual depreciation expense, the required depreciation rate to be applied against the original cost of the account and the estimated composite remaining life of the surviving plant in service.

The detailed calculations of annual depreciation applicable to depreciable assets, as of December 31, 2021, are presented in account sequence starting in Section 5 – Page 5-2. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth (for each installation year) the original cost, calculated accrued depreciation and the calculated annual accrual.

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN COMMON PLANT AS OF DECEMBER 31, 2021

- TOTAL -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE	REMAINING LIFE
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	40-R2	-5	57,959,115	16,797,415	17,279,728	1,490,513	2.57%	29.0
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	1,006,971	980,352	144,983	6.81%	7.9
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	1,803,390	1,465,895	886,780	24.37%	2.5
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	990,748	806,878	484,639	23.70%	2.6
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	15	18,482	4,321	4,252	633	3.42%	18.1
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	20	8,552,949	2,647,624	1,941,593	825,496	9.65%	6.1
393.0	STORES EQUIPMENT	30-SQ	0	174,519	44,725	50,428	5,123	2.94%	22.3
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	329,182	602,422	9,640	1.27%	11.3
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	36,560	36,561	2,328	5.00%	4.3
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	3,147	3,815	-	0.00%	3.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	1,108,474	1,075,983	172,894	7.04%	8.2
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	658,235	644,848	75,385	7.05%	5.8
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	508,725	483,979	80,619	11.83%	2.5
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	11,645	7,698	4,356	27.74%	2.6
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	187,973	139,218	97,514	25.14%	2.6
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	529,827	695,508	47,067	3.05%	16.4
TOTAL GENERAL PLANT				**81,481,558**	**26,668,962**	**26,219,158**	**4,327,970**	**5.31%**	
TOTAL COMMON PLANT STUDIED				**81,481,558**	**26,668,962**	**26,219,158**	**4,327,970**	**5.31%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437					
389.0	LAND & LAND RIGHTS GENERAL			3,285,775					
392.3	AIRCRAFT EQUIPMENT			5,104,289					
TOTAL PLANT				157,961,059					

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1A. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF AVERAGE ORIGINAL COST IN COMMON PLANT AS OF DECEMBER 31, 2021

- LIFE -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE	REMAINING LIFE
GENERAL PLANT									
390.0	STRUCTURES & IMPROVEMENTS	40-R2	0	57,959,115	15,997,538	18,045,786	1,318,028	2.27%	29.0
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	1,006,971	980,352	144,983	6.81%	7.9
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	1,803,390	1,465,895	886,780	24.37%	2.5
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	990,748	806,878	484,639	23.70%	2.6
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	15	18,482	4,321	4,252	633	3.42%	18.1
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	20	8,552,949	2,647,624	1,941,593	825,496	9.65%	6.1
393.0	STORES EQUIPMENT	30-SQ	0	174,519	44,725	50,428	5,123	2.94%	22.3
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	329,182	602,422	9,640	1.27%	11.3
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	36,560	36,561	2,328	5.00%	4.3
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	3,147	3,815	-	0.00%	3.5
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	1,108,474	1,075,983	172,894	7.04%	8.2
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	658,235	644,848	75,385	7.05%	5.8
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	508,725	483,979	80,619	11.83%	2.5
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	11,645	7,698	4,356	27.74%	2.6
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	187,973	139,218	97,514	25.14%	2.6
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	529,827	695,508	47,067	3.05%	16.4
TOTAL GENERAL PLANT				**81,481,558**	**25,869,085**	**26,985,216**	**4,155,485**	**5.10%**	
TOTAL COMMON PLANT STUDIED				**81,481,558**	**25,869,085**	**26,985,216**	**4,155,485**	**5.10%**	
PLANT NOT STUDIED									
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437					
389.0	LAND & LAND RIGHTS GENERAL			3,285,775					
392.3	AIRCRAFT EQUIPMENT			5,104,289					
TOTAL PLANT				157,961,059					

MONTANA-DAKOTA UTILITIES CO. - COMMON PLANT

TABLE 1B. REVISED SUMMARY OF SERVICE LIFE AND NET SALVAGE ESTIMATES AND CALCULATED ANNUAL AND ACCRUED DEPRECIATION RELATED TO THE RECOVERY OF NET SALVAGE IN COMMON PLANT AS OF DECEMBER 31, 2021

- NET SALVAGE -

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVING ORIGINAL COST AS OF 12/31/2021	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE	ACCRUAL AMOUNT	RATE
GENERAL PLANT								
390.0	STRUCTURES & IMPROVEMENTS	40-R2	-5	57,959,115	799,877	(766,058)	172,485	0.30%
391.1	OFFICE FURNITURE & EQUIPMENT	15-SQ	0	2,130,096	-	-	-	0.00%
391.3	COMPUTER EQUIPMENT - PC	5-SQ	0	3,638,802	-	-	-	0.00%
391.5	COMPUTER EQUIPMENT - OTHER	5-SQ	0	2,045,305	-	-	-	0.00%
392.1	TRANSPORTATION EQUIPMENT - TRAILERS	25-R1	0	18,482	-	-	-	0.00%
392.2	TRANSPORTATION EQUIPMENT	10-L2.5	0	8,552,949	-	-	-	0.00%
393.0	STORES EQUIPMENT	30-SQ	0	174,519	-	-	-	0.00%
394.1	TOOLS, SHOP, & GARAGE EQUIPMENT	20-SQ	0	759,520	-	-	-	0.00%
394.3	VEHICLE MAINTENANCE EQUIPMENT	20-SQ	0	46,590	-	-	-	0.00%
394.4	VEHICLE REFUELING EQUIPMENT	20-SQ	0	3,815	-	-	-	0.00%
397.1	COMMUNICATION EQUIPMENT - FIXED RADIOS	15-SQ	0	2,454,294	-	-	-	0.00%
397.2	COMMUNICATION EQUIPMENT - MOBILE RADIOS	15-SQ	0	1,069,272	-	-	-	0.00%
397.3	GENERAL TELEPHONE COMMUNICATION EQUIPMENT	10-SQ	0	681,544	-	-	-	0.00%
397.5	SUPERVISORY & TELEMETERING EQUIPMENT	10-SQ	0	15,704	-	-	-	0.00%
397.8	NETWORK EQUIPMENT	5-SQ	0	387,937	-	-	-	0.00%
398.0	MISCELLANEOUS EQUIPMENT	25-SQ	0	1,543,614	-	-	-	0.00%
TOTAL GENERAL PLANT				**81,481,558**	**799,877**	**(766,058)**	**172,485**	**0.21%**
TOTAL COMMON PLANT STUDIED				**81,481,558**	**799,877**	**(766,058)**	**172,485**	**0.21%**
PLANT NOT STUDIED								
303.0	MISCELLANEOUS INTANGIBLE PLANT			68,089,437				
389.0	LAND & LAND RIGHTS GENERAL			3,285,775				
392.3	AIRCRAFT EQUIPMENT			5,104,289				
TOTAL PLANT				157,961,059				

SECTION 6

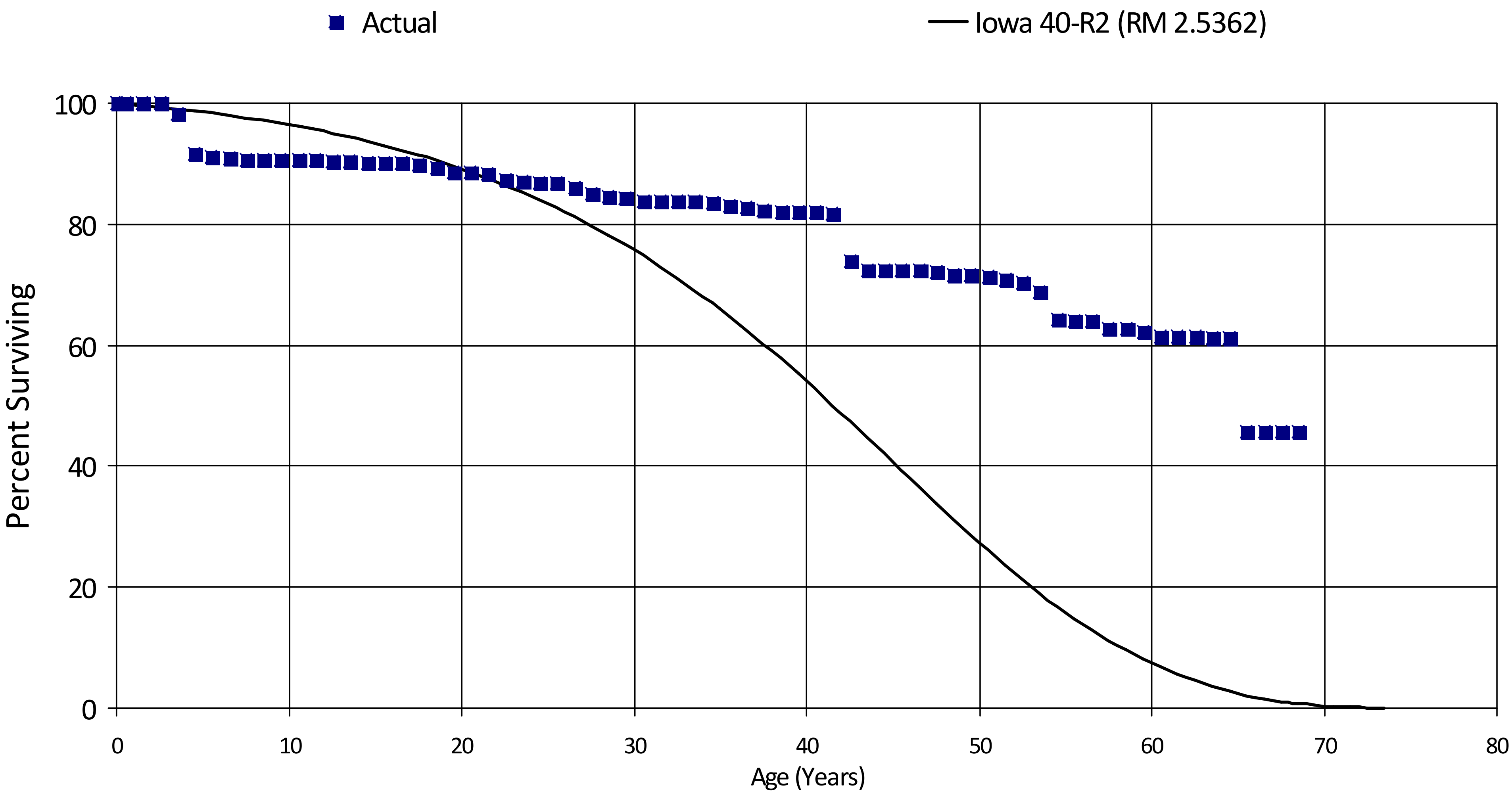
6 RETIREMENT RATE ANALYSIS

MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	65,766,039	13,475	0.00020	0.99980	100.00
0.5	65,679,966	39,092	0.00060	0.99940	99.98
1.5	57,830,913	20,887	0.00036	0.99964	99.92
2.5	56,318,909	1,003,331	0.01782	0.98218	99.88
3.5	52,804,475	3,429,736	0.06495	0.93505	98.10
4.5	45,614,835	263,478	0.00578	0.99422	91.73
5.5	43,986,084	142,215	0.00323	0.99677	91.20
6.5	43,276,893	110,672	0.00256	0.99744	90.91
7.5	27,321,253	24,730	0.00091	0.99909	90.68
8.5	26,974,929	4,989	0.00018	0.99982	90.60
9.5	25,865,503	13,890	0.00054	0.99946	90.58
10.5	25,422,780	0	0.00000	1.00000	90.53
11.5	23,139,844	16,504	0.00071	0.99929	90.53
12.5	23,123,340	40,006	0.00173	0.99827	90.47
13.5	22,285,383	48,884	0.00219	0.99781	90.31
14.5	22,065,083	4,793	0.00022	0.99978	90.11
15.5	22,040,286	15,872	0.00072	0.99928	90.09
16.5	18,129,628	33,129	0.00183	0.99817	90.03
17.5	16,870,206	112,893	0.00669	0.99331	89.87
18.5	16,566,860	130,387	0.00787	0.99213	89.27
19.5	16,029,336	0	0.00000	1.00000	88.57
20.5	15,862,316	59,046	0.00372	0.99628	88.57
21.5	15,171,557	144,610	0.00953	0.99047	88.24
22.5	14,844,554	51,782	0.00349	0.99651	87.40
23.5	14,607,148	40,651	0.00278	0.99722	87.09
24.5	13,922,697	9,569	0.00069	0.99931	86.85
25.5	13,624,592	136,345	0.01001	0.98999	86.79
26.5	23,910,259	227,418	0.00951	0.99049	85.92

MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021 Experience Band - 2009 - 2021

27.5	21,009,324	148,104	0.00705	0.99295	85.10
28.5	20,522,861	27,625	0.00135	0.99865	84.50
29.5	20,166,019	139,561	0.00692	0.99308	84.39
30.5	19,921,820	24	0.00000	1.00000	83.81
31.5	19,820,262	21,480	0.00108	0.99892	83.81
32.5	19,764,835	8,757	0.00044	0.99956	83.72
33.5	19,746,416	35,112	0.00178	0.99822	83.68
34.5	19,705,848	130,913	0.00664	0.99336	83.53
35.5	19,190,872	38,262	0.00199	0.99801	82.98
36.5	18,083,098	101,848	0.00563	0.99437	82.81
37.5	11,575,849	63,298	0.00547	0.99453	82.34
38.5	10,681,923	0	0.00000	1.00000	81.89
39.5	7,282,278	0	0.00000	1.00000	81.89
40.5	6,991,807	10,837	0.00155	0.99845	81.89
41.5	6,462,831	629,902	0.09747	0.90253	81.76
42.5	4,657,096	97,810	0.02100	0.97900	73.79
43.5	4,532,160	-13,846	-0.00306	1.00306	72.24
44.5	4,021,935	6,046	0.00150	0.99850	72.46
45.5	3,972,989	0	0.00000	1.00000	72.35
46.5	3,972,989	9,424	0.00237	0.99763	72.35
47.5	3,937,914	27,540	0.00699	0.99301	72.18
48.5	3,812,362	0	0.00000	1.00000	71.68
49.5	3,363,329	11,960	0.00356	0.99644	71.68
50.5	3,293,627	29,387	0.00892	0.99108	71.42
51.5	3,261,294	18,061	0.00554	0.99446	70.78
52.5	3,074,356	67,113	0.02183	0.97817	70.39
53.5	738,579	49,944	0.06762	0.93238	68.85
54.5	523,232	2,459	0.00470	0.99530	64.19
55.5	150,655	0	0.00000	1.00000	63.89
56.5	143,620	2,816	0.01961	0.98039	63.89
57.5	80,158	0	0.00000	1.00000	62.64

MDU Common

Account 390.00 - Structures & Improvements

Placement Band - 1952 - 2021   Experience Band - 2009 - 2021

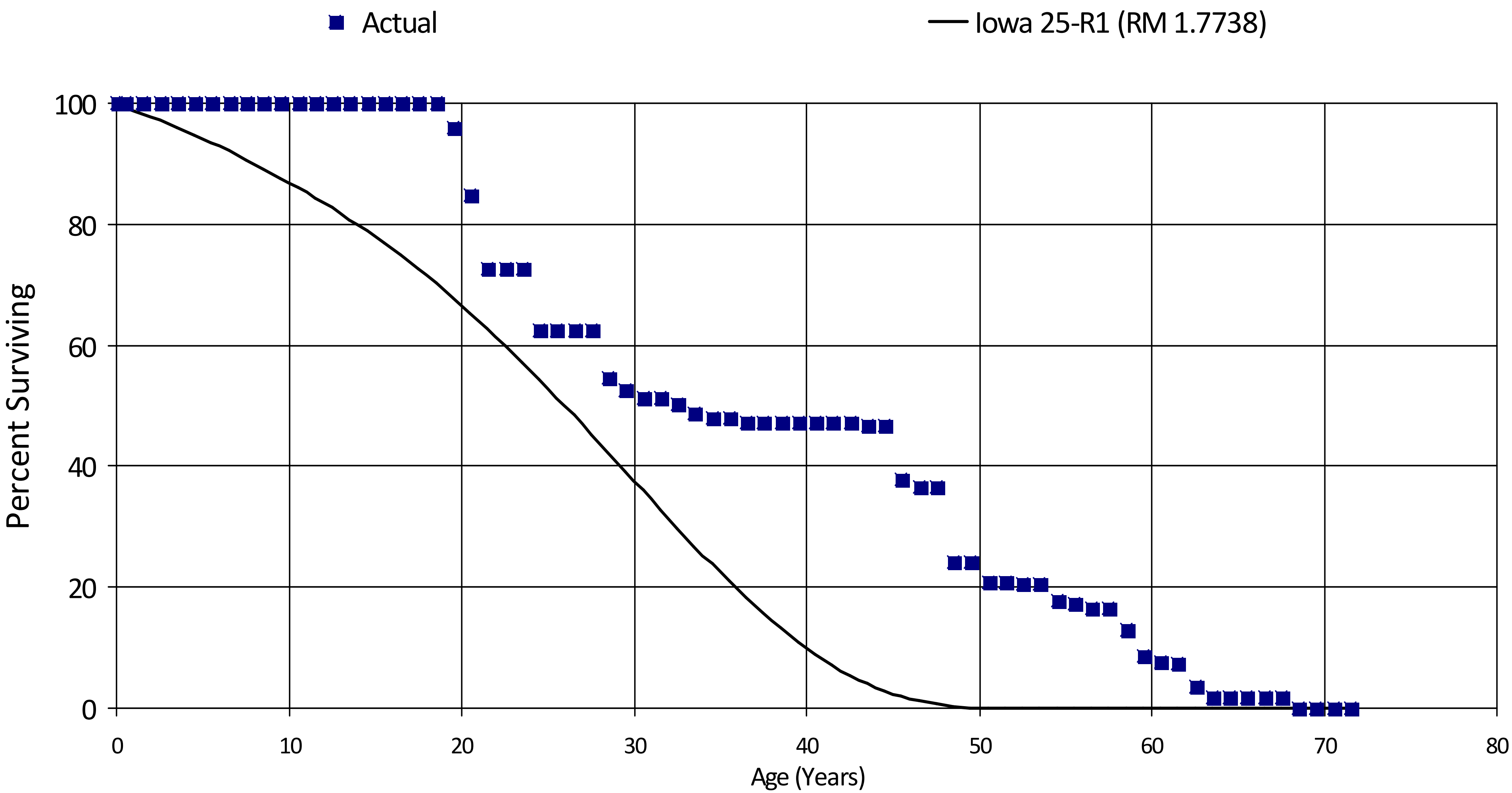
58.5	82,900	630	0.00760	0.99240	62.64
59.5	67,751	891	0.01315	0.98685	62.16
60.5	65,325	0	0.00000	1.00000	61.34
61.5	63,239	0	0.00000	1.00000	61.34
62.5	62,367	185	0.00297	0.99703	61.34
63.5	61,320	0	0.00000	1.00000	61.16
64.5	9,503	2,393	0.25182	0.74818	61.16
65.5	4,602	0	0.00000	1.00000	45.76
66.5	4,585	0	0.00000	1.00000	45.76
67.5	1,102	0	0.00000	1.00000	45.76
68.5	-2,393	0	0.00000	1.00000	45.76
	Totals:	7,806,920			

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021 Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	74,048	0	0.00000	1.00000	100.00
0.5	74,048	0	0.00000	1.00000	100.00
1.5	74,048	0	0.00000	1.00000	100.00
2.5	74,048	0	0.00000	1.00000	100.00
3.5	74,048	0	0.00000	1.00000	100.00
4.5	74,048	0	0.00000	1.00000	100.00
5.5	74,048	0	0.00000	1.00000	100.00
6.5	74,048	0	0.00000	1.00000	100.00
7.5	74,048	0	0.00000	1.00000	100.00
8.5	71,565	0	0.00000	1.00000	100.00
9.5	62,980	0	0.00000	1.00000	100.00
10.5	55,566	0	0.00000	1.00000	100.00
11.5	55,566	0	0.00000	1.00000	100.00
12.5	55,566	0	0.00000	1.00000	100.00
13.5	55,566	0	0.00000	1.00000	100.00
14.5	55,566	0	0.00000	1.00000	100.00
15.5	55,566	0	0.00000	1.00000	100.00
16.5	55,566	0	0.00000	1.00000	100.00
17.5	55,566	0	0.00000	1.00000	100.00
18.5	55,566	2,295	0.04130	0.95870	100.00
19.5	53,271	6,178	0.11597	0.88403	95.87
20.5	47,093	6,781	0.14399	0.85601	84.75
21.5	40,312	0	0.00000	1.00000	72.55
22.5	40,312	0	0.00000	1.00000	72.55
23.5	40,312	5,664	0.14050	0.85950	72.55
24.5	34,648	0	0.00000	1.00000	62.36
25.5	34,648	0	0.00000	1.00000	62.36
26.5	34,648	0	0.00000	1.00000	62.36

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

27.5	34,648	4,278	0.12347	0.87653	62.36
28.5	30,371	1,112	0.03661	0.96339	54.66
29.5	29,258	748	0.02557	0.97443	52.66
30.5	28,511	0	0.00000	1.00000	51.31
31.5	28,511	611	0.02143	0.97857	51.31
32.5	27,900	776	0.02781	0.97219	50.21
33.5	27,123	448	0.01652	0.98348	48.81
34.5	26,675	0	0.00000	1.00000	48.00
35.5	26,675	402	0.01507	0.98493	48.00
36.5	26,272	0	0.00000	1.00000	47.28
37.5	26,272	0	0.00000	1.00000	47.28
38.5	26,272	0	0.00000	1.00000	47.28
39.5	26,272	0	0.00000	1.00000	47.28
40.5	26,272	0	0.00000	1.00000	47.28
41.5	26,272	0	0.00000	1.00000	47.28
42.5	26,272	365	0.01389	0.98611	47.28
43.5	25,907	0	0.00000	1.00000	46.62
44.5	25,907	4,902	0.18921	0.81079	46.62
45.5	21,005	671	0.03194	0.96806	37.80
46.5	20,334	0	0.00000	1.00000	36.59
47.5	20,334	6,950	0.34179	0.65821	36.59
48.5	13,384	0	0.00000	1.00000	24.08
49.5	13,384	1,758	0.13135	0.86865	24.08
50.5	11,627	0	0.00000	1.00000	20.92
51.5	11,627	254	0.02185	0.97815	20.92
52.5	11,373	0	0.00000	1.00000	20.46
53.5	11,373	1,439	0.12652	0.87348	20.46
54.5	9,934	333	0.03352	0.96648	17.87
55.5	9,601	417	0.04343	0.95657	17.27
56.5	9,184	0	0.00000	1.00000	16.52
57.5	9,184	2,021	0.22005	0.77995	16.52

MDU Common

Account 392.10 - Transportation Equipment - Trailers

Placement Band - 1937 - 2021   Experience Band - 2009 - 2021

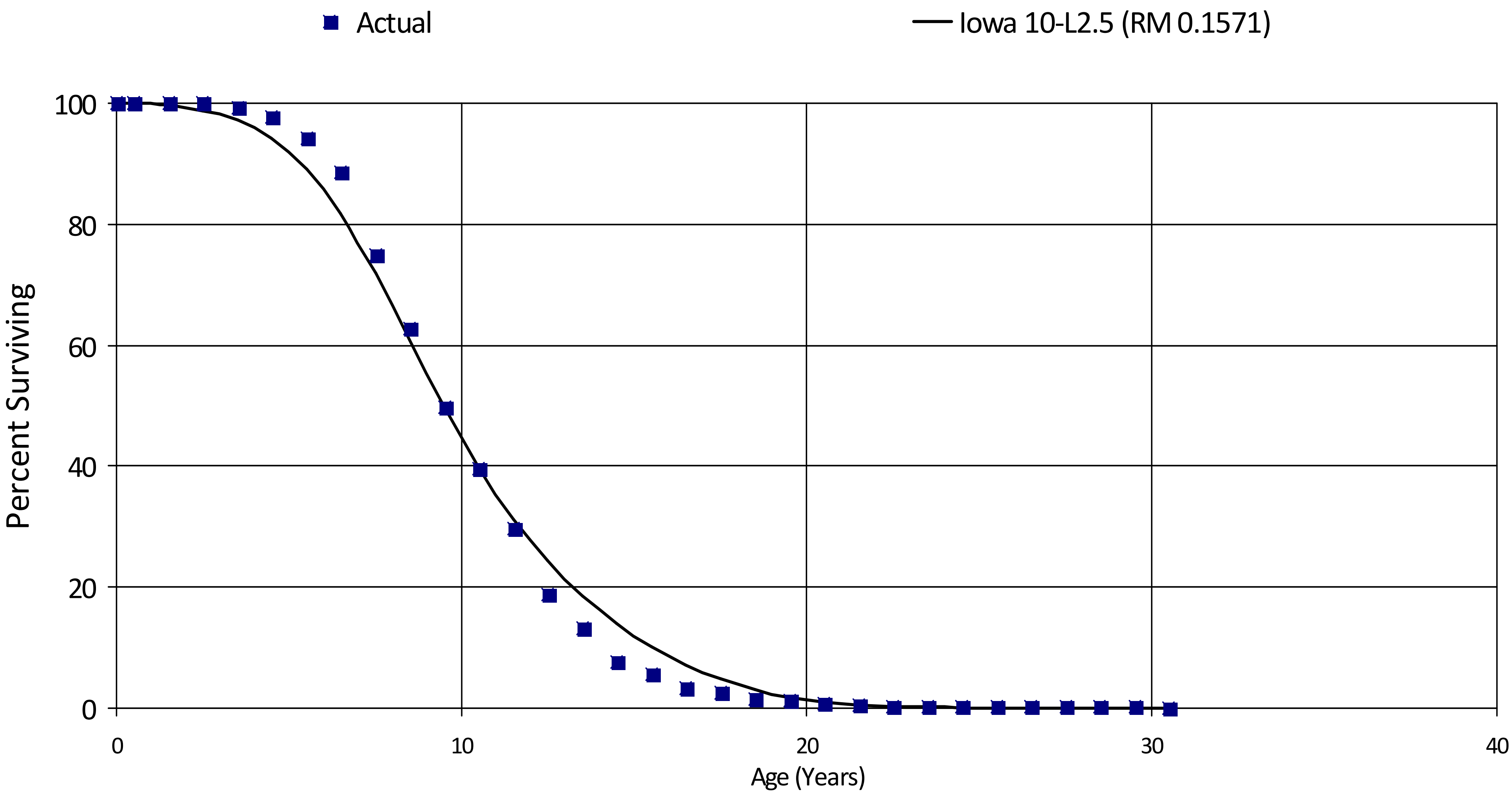
58.5	7,163	2,418	0.33755	0.66245	12.88
59.5	4,745	551	0.11611	0.88389	8.53
60.5	4,195	56	0.01335	0.98665	7.54
61.5	4,139	2,155	0.52066	0.47934	7.44
62.5	1,984	1,012	0.51008	0.48992	3.57
63.5	972	0	0.00000	1.00000	1.75
64.5	972	0	0.00000	1.00000	1.75
65.5	972	0	0.00000	1.00000	1.75
66.5	972	0	0.00000	1.00000	1.75
67.5	972	947	0.97447	0.02553	1.75
68.5	25	0	0.00000	1.00000	0.04
69.5	25	0	0.00000	1.00000	0.04
70.5	25	0	0.00000	1.00000	0.04
71.5	25	25	1.00000		0.04
	Totals:	55,567			

MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021 Experience Band - 2009 - 2021

Actual and Smooth Survivor Curves



MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021   Experience Band - 2009 - 2021

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,154,373	0	0.00000	1.00000	100.00
0.5	15,921,146	0	0.00000	1.00000	100.00
1.5	14,926,282	13,683	0.00092	0.99908	100.00
2.5	13,066,738	85,792	0.00657	0.99343	99.91
3.5	12,019,875	196,860	0.01638	0.98362	99.25
4.5	10,971,841	387,493	0.03532	0.96468	97.62
5.5	9,209,486	538,637	0.05849	0.94151	94.17
6.5	7,744,781	1,209,555	0.15618	0.84382	88.66
7.5	5,936,758	968,739	0.16318	0.83682	74.81
8.5	4,799,794	989,697	0.20620	0.79380	62.60
9.5	3,476,252	705,665	0.20300	0.79700	49.69
10.5	2,583,629	648,788	0.25111	0.74889	39.60
11.5	1,896,318	697,431	0.36778	0.63222	29.66
12.5	1,198,887	358,698	0.29919	0.70081	18.75
13.5	840,189	345,824	0.41160	0.58840	13.14
14.5	467,451	127,299	0.27233	0.72767	7.73
15.5	340,151	141,041	0.41464	0.58536	5.62
16.5	199,110	48,943	0.24581	0.75419	3.29
17.5	150,167	54,251	0.36127	0.63873	2.48
18.5	95,916	24,033	0.25056	0.74944	1.58
19.5	58,994	22,124	0.37502	0.62498	1.18
20.5	36,870	12,603	0.34182	0.65818	0.74
21.5	24,268	15,588	0.64233	0.35767	0.49
22.5	8,680	0	0.00000	1.00000	0.18
23.5	8,680	0	0.00000	1.00000	0.18
24.5	8,680	0	0.00000	1.00000	0.18
25.5	8,680	0	0.00000	1.00000	0.18
26.5	8,680	0	0.00000	1.00000	0.18

MDU Common

Account 392.20 - Transportation Equipment

Placement Band - 1979 - 2021   Experience Band - 2009 - 2021

27.5	8,680	0	0.00000	1.00000	0.18
28.5	8,680	0	0.00000	1.00000	0.18
29.5	8,680	8,680	1.00005	-0.00005	0.18
30.5	0	0	0.00000	0.00000	0.00
	Totals:	7,601,424			

SECTION 7

7 NET SALVAGE

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 390 - GENERAL PLANT - STRUCTURES & IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1968	4,756	40	1	(662)	(14)	622	13					622	13
1969	23,146	979	4	(350)	(2)	(629)	-3					-3	0
1970	9,536	1,402	15	(5,551)	(58)	4,149	44	1,381	11			1,381	11
1971	56	1,458	2,626	(816)	(1,470)	(642)	-1,156	960	9			875	9
1972	89,020	100	0	(20,851)	(23)	20,751	23	8,086	25	4,850	19	4,850	19
1973	823	-	0	(556)	(68)	556	68	6,888	23	4,837	20	4,135	19
1974	6,649	2,381	36	0	0	(2,381)	-36	6,309	20	4,487	21	3,204	17
1975	0	-		0		0		-608	-24	3,657	19	3,204	17
1976	699	18	3	0	0	(18)	-3	-800	-33	3,782	19	2,801	17
1977	33,563	7,368	22	(10)	(0)	(7,358)	-22	-2,459	-22	-1,840	-22	1,672	9
1978	5,945	471	8	(167)	(3)	(304)	-5	-2,560	-19	-2,012	-21	1,475	8
1979	362	29	8	2	1	(31)	-9	-2,564	-19	-1,542	-19	1,338	8
1980	36,429	-	0	(46,043)	(126)	46,043	126	15,236	107	7,666	50	5,063	29
1981	386	-	0	0	0	0	0	15,337	124	7,670	50	5,063	29
1982	2,390	-	0	35,198	1,473	(35,198)	-1,473	3,615	28	2,102	23	1,966	12
1983	151,268	17,106	11	(52,055)	(34)	34,949	23	-83	0	9,152	24	4,322	17
1984	0	-		(240)		240		-3	0	9,207	24	4,050	17
1985	29,321	-	0	0	0	0	0	11,730	19	-2	0	4,050	15
1986	353,206	23,017	7	(463)	(0)	(22,554)	-6	-7,438	-6	-4,513	-4	2,387	5
1987	114,669	178,551	156	(7)	(0)	(178,544)	-156	-67,033	-40	-33,182	-26	-8,256	-16
1988	1,066	44,428	4,168	(20)	(2)	(44,408)	-4,167	-81,835	-52	-49,053	-49	-10,264	-21
1989	2,908	1,362	47	0	0	(1,362)	-47	-74,771	-189	-49,374	-49	-9,796	-21
1990	1,179	4,184	355	0	0	(4,184)	-355	-16,651	-969	-50,210	-53	-9,515	-22
1991	11,318	21,000	186	0	0	(21,000)	-186	-8,848	-172	-49,899	-190	-10,062	-24
1992	6,400	59,486	929	0	0	(59,486)	-929	-28,223	-448	-26,088	-570	-12,309	-31
1993	66,938	11,015	16	(5,500)	(8)	(5,515)	-8	-28,667	-102	-18,309	-103	-12,013	-29
1994	76,340	3,348	4	(53)	(0)	(3,296)	-4	-22,765	-46	-18,696	-58	-11,650	-27
1995	249,269	48,516	19	(188,096)	(75)	139,580	56	43,590	33	10,057	12	-5,601	-11
1996	174,572	22,546	13	(26,753)	(15)	4,207	2	46,830	28	15,098	13	-5,224	-9
1997	97788.56	4,265	4	(45,364)	(46)	41,099	42	61,629	35	35,215	26	-3,508	-6
1998	255,812	40,399	16		0	(40,399)	-16	1,636	1	28,238	17	-4,825	-7
1999	303792.23	12,226	4	(30,685)	(10)	18,459	6	6,386	3	32,589	15	-4,023	-6
2000	172,070	30,935	18	(10,284)	(6)	(20,651)	-12	-14,197	-6	543	0	-4,577	-6
2001	109,760	14,719	13		0	(14,719)	-13	-5,637	-3	-3,242	-2	-4,904	-6
2002	110,036	29,202	27		0	(29,202)	-27	-21,524	-16	-17,302	-9	-5,663	-7
2003	16416	-	0		0	0	0	-14,640	-19	-9,223	-6	-5,663	-7
2004	0	26,474		(639,099)		612,625		194,474	461	109,611	134	13,073	17
2005	(32,273)	225	(1)		0	(225)	1	204,133	-3,862	113,696	279	12,682	17
2006	13,529	9,973	74	(330,000)	(2,439)	320,028	2,365	310,809	-4,975	180,645	839	21,463	30
2007	45,025	14,205	32	(111,000)	(247)	96,795	215	138,866	1,585	205,845	2,410	23,555	33
2008	26,949	2,070	8		0	(2,070)	-8	138,251	485	205,430	1,930	22,863	33

Montana-Dakota Utilities Co. - Common Plant

ACCOUNT 390 - GENERAL PLANT - STRUCTURES & IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2009	542,058	41,867	8	(526,444)	(97)	484,577	89	193,101	94	179,821	151	35,013	43
2010	59,049	3,138		(244)		(2,894)		159,871	76	179,287	131	34,041	42
2011	88,464	19,861	22	(453)	(1)	(19,408)	-22	154,091	67	111,400	73	32,705	40
2012	192,754	3,872	2	(250)	(0)	(3,622)	-2	-8,641	-8	91,316	50	31,819	38
2013	11,998					0		-7,677	-8	91,730	51	31,819	38
2014	762,013	1,212	0		0	(1,212)	0	-1,611	0	-5,427	-2	31,033	31
2015	28,556	93,108	326		0	(93,108)	-326	-31,440	-12	-23,470	-11	28,146	28
2016	4,973,129	120,759	2	(1,250,383)	(25)	1,129,624	23	345,101	18	206,337	17	53,179	25
2017	177,483	191,183	108	(91,149)	(51)	(100,034)	-56	312,161	18	187,054	16	49,774	24
2018	165,707	28,937	17	(1,000)	(1)	(27,937)	-17	333,884	19	181,467	15	48,085	23
2019	282,192	60,776	22	(9,760)	(3)	(51,016)	-18	-59,662	-29	171,506	15	45,977	22
2020	301,002	77,992	26		0	(77,992)	-26	-52,315	-21	174,529	15	43,394	21
2021	222,519.29	124,870	56	(179,182)	(81)	54,312	24	-24,899	-9	-40,533	-18	43,617	21
TOTAL	**10,378,043**	**1,401,070**	**13.50**	**-3,538,286**	**(34.09)**	**2,137,217**	**20.59**						

Montana-Dakota Utilities Co. - Common Plant

ACCOUNT 392.1 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - TRAILERS

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2005	0			(3,500)		3,500						3,500	0
2006	0					0						3,500	0
2007	0			(950)		950		1,483	0			2,225	0
2008	0			(4,850)		4,850		1,933	0			3,100	0
2009	26,134		0	(385)	(1)	385	1	3,228	37	1,937	37	2,421	37
2010	6,896		0	(476)	(7)	476	7	3,387	31	1,332	20	2,032	31
2011	10,083		0	(680)	(7)	680	7	3,614	25	1,468	17	1,807	25
2012	12,453		0	(2,853)	(23)	2,853	23	1,336	14	1,849	17	1,956	25
2013						0		1,178	16	879	8	1,956	25
2014						0		951	23	802	14	1,956	25
2015						0		0	0	707	16	1,956	25
2016						0		0	0	571	23	1,956	25
2017				(4,155)		4,155		1,385	0	831	0	2,231	32
2018				(3,720)		3,720		2,625	0	1,575	0	2,397	39
2019				(19,050)		19,050		8,975	0	5,385	0	4,062	73
2020						0		7,590	0	5,385	0	4,062	73
2021						0		6,350	0	5,385	0	4,062	73
TOTAL	**55,566**	**0**	**0.00**	**-40,619**	**(73.10)**	**40,619**	**73.10**						

Montana-Dakota Utilities Co. - Common Plant
ACCOUNT 392.2 - GENERAL PLANT - TRANSPORTATION EQUIPMENT - VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2004	0			(124,143)		124,143						124,143	0
2005	0			(74,531)		74,531						99,337	0
2006	0			(112,620)		112,620		103,765	0			103,765	0
2007	0			(143,063)		143,063		110,071	0			113,589	0
2008	0			(123,203)		123,203		126,295	0	115,512	0	115,512	0
2009	943,733		0	(192,584)	(20)	192,584	20	152,950	49	129,200	68	128,357	82
2010	465,031		0	(126,147)	(27)	126,147	27	147,311	31	139,523	50	128,042	64
2011	137,474		0	(33,401)	(24)	33,401	24	117,377	23	123,680	40	116,211	60
2012	228,230		0	(85,168)	(37)	85,168	37	81,572	29	112,100	32	112,762	57
2013	65,494		0	(49,347)	(75)	49,347		55,972	39	97,329	26	106,421	58
2014	507,650		0	(128,676)	(25)	128,676	25	87,730	33	84,548	30	108,444	51
2015	565,400		0	(135,436)	(24)	135,436	24	104,486	28	86,405	29	110,693	46
2016	1,307,335		0	(135,238)	(10)	135,238	10	133,117	17	106,773	20	112,581	35
2017	832,091	(2)	(0)	(127,071)	(15)	127,073	15	132,582	15	115,154	18	113,616	31
2018	487,481	(15)	(0)	(170,917)	(35)	170,932	35	144,414	16	139,471	19	117,437	32
2019	873,014		0	(198,937)	(23)	198,937	23	165,647	23	153,523	19	122,531	31
2020	734,877		0	(250,036)	(34)	250,036	34	206,635	30	176,443	21	130,031	31
2021	453,616		0	(146,366)	(32)	146,366		198,446	29	178,669	26	130,939	31
TOTAL	**7,601,424**	**(17)**	**(0.00)**	**-2,356,882**	**(31.01)**	**2,356,899**	**31.01**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATIONS

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1953	1,101.98	1,112	1,144	0.9888	13	1.55	8	68.5
1954	863.89	866	891	0.9819	16	1.82	9	67.5
1956	2,508.43	2,478	2,549	0.9677	85	2.37	36	65.5
1957	8,477.14	8,310	8,548	0.9604	353	2.66	133	64.5
1958	708.02	689	709	0.9531	35	2.94	12	63.5
1959	413.04	399	410	0.9462	23	3.23	7	62.5
1960	2,078.30	1,990	2,048	0.9383	135	3.52	38	61.5
1961	1,232.59	1,171	1,205	0.9308	90	3.81	24	60.5
1962	5,940.05	5,598	5,759	0.9234	478	4.10	117	59.5
1964	18,983.94	17,601	18,107	0.9084	1,826	4.68	390	57.5
1965	3,056.19	2,810	2,891	0.9008	318	4.97	64	56.5
1966	143,317.20	130,649	134,400	0.8931	16,083	5.27	3,051	55.5
1967	161,052.17	145,537	149,716	0.8853	19,389	5.57	3,478	54.5
1968	806,161.69	721,976	742,707	0.8774	103,763	5.88	17,638	53.5
1969	49,712.30	44,110	45,377	0.8693	6,821	6.20	1,101	52.5
1971	35,288.82	30,706	31,588	0.8525	5,466	6.85	798	50.5
1972	423,317.91	364,546	375,014	0.8437	69,470	7.19	9,657	49.5
1973	29,001.76	24,707	25,416	0.8346	5,035	7.55	667	48.5
1974	16,140.20	13,596	13,986	0.8253	2,961	7.91	374	47.5
1976	36,819.79	30,275	31,144	0.8056	7,516	8.68	866	45.5
1977	299,565.32	243,149	250,131	0.7952	64,413	9.08	7,095	44.5
1978	6,271.01	5,021	5,166	0.7845	1,419	9.50	149	43.5
1979	516,956.94	408,091	419,809	0.7734	122,996	9.93	12,390	42.5
1980	243,249.46	189,177	194,609	0.7619	60,803	10.37	5,862	41.5
1981	178,300.70	136,511	140,430	0.7501	46,785	10.83	4,319	40.5
1982	1,478,135.25	1,113,244	1,145,209	0.7379	406,833	11.31	35,975	39.5
1983	320,357.51	237,151	243,961	0.7253	92,415	11.80	7,832	38.5
1984	2,770,584.09	2,014,235	2,072,070	0.7123	837,043	12.30	68,027	37.5

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	505,787.81	360,806	371,166	0.6989	159,912	12.82	12,469	36.5
1986	233,540.28	163,317	168,007	0.6851	77,210	13.36	5,779	35.5
1988	4,844.35	3,246	3,339	0.6565	1,747	14.47	121	33.5
1989	4,397.52	2,880	2,963	0.6416	1,655	15.05	110	32.5
1991	59,438.01	37,055	38,119	0.6108	24,291	16.25	1,495	30.5
1992	153,963.54	93,480	96,164	0.5948	65,498	16.87	3,882	29.5
1993	301,888.43	178,276	183,395	0.5786	133,588	17.50	7,632	28.5
1994	2,219,352.92	1,272,963	1,309,515	0.5619	1,020,806	18.15	56,244	27.5
1995	552,945.17	307,591	316,423	0.5450	264,169	18.81	14,045	26.5
1996	288,535.48	155,421	159,884	0.5277	143,078	19.48	7,345	25.5
1997	643,800.12	335,236	344,862	0.5102	331,129	20.16	16,422	24.5
1998	182,161.40	91,529	94,157	0.4923	97,112	20.86	4,656	23.5
1999	182,391.90	88,260	90,794	0.4741	100,717	21.57	4,670	22.5
2000	631,714.02	293,778	302,214	0.4556	361,086	22.28	16,204	21.5
2001	167,019.55	74,475	76,613	0.4369	98,757	23.01	4,291	20.5
2002	407,136.47	173,635	178,621	0.4178	248,872	23.75	10,477	19.5
2003	190,452.63	77,472	79,696	0.3985	120,279	24.50	4,909	18.5
2004	1,226,294.00	474,335	487,955	0.3790	799,654	25.26	31,651	17.5
2005	3,894,785.97	1,427,704	1,468,698	0.3591	2,620,827	26.04	100,664	16.5
2006	20,003.59	6,923	7,122	0.3391	13,882	26.82	518	15.5
2007	171,416.43	55,767	57,369	0.3187	122,619	27.61	4,442	14.5
2008	797,951.24	242,851	249,825	0.2982	588,024	28.41	20,701	13.5
2010	2,282,936.10	597,345	614,497	0.2564	1,782,586	30.03	59,356	11.5
2011	428,832.46	102,907	105,861	0.2351	344,413	30.86	11,161	10.5
2012	1,104,436.85	240,834	247,749	0.2136	911,910	31.69	28,773	9.5
2013	321,593.54	63,012	64,821	0.1920	272,852	32.54	8,386	8.5
2014	15,844,968.08	2,750,706	2,829,689	0.1701	13,807,528	33.39	413,565	7.5
2015	566,977.13	85,649	88,108	0.1480	507,218	34.25	14,811	6.5

MDU Common

Account #: 390.00 - Structures & Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2016	1,365,272.00	175,199	180,230	0.1257	1,253,306	35.11	35,695	5.5
2017	3,759,904.19	396,279	407,658	0.1033	3,540,242	35.98	98,381	4.5
2018	2,511,103.30	206,614	212,547	0.0806	2,424,112	36.87	65,756	3.5
2019	1,491,116.43	87,951	90,477	0.0578	1,475,196	37.75	39,075	2.5
2020	7,809,961.18	277,351	285,315	0.0348	7,915,144	38.65	204,805	1.5
2021	72,597.36	862	887	0.0116	75,341	39.55	1,905	0.5
TOTAL	57,959,115.14	16,797,415	17,279,728		43,577,343		1,490,513	

COMPOSITE ANNUAL ACCRUAL RATE 2.57%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.30

COMPOSITE AVERAGE AGE (YEARS) 14.00

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 28.96

MDU Common

Account #: 391.10 - Office Furniture & Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	168,807.34	163,180	158,867	0.9411	9,941	0.50	9,940	14.5
2008	81,864.85	73,678	71,731	0.8762	10,134	1.50	6,756	13.5
2010	32,157.67	24,654	24,002	0.7464	8,155	3.50	2,330	11.5
2011	74,683.24	52,278	50,896	0.6815	23,787	4.50	5,286	10.5
2012	216,594.23	137,176	133,550	0.6166	83,044	5.50	15,099	9.5
2013	137,346.05	77,829	75,772	0.5517	61,574	6.50	9,473	8.5
2014	551,783.78	275,892	268,599	0.4868	283,185	7.50	37,758	7.5
2015	232,350.52	100,685	98,024	0.4219	134,327	8.50	15,803	6.5
2016	76,630.17	28,098	27,355	0.3570	49,275	9.50	5,187	5.5
2017	62,199.61	18,660	18,167	0.2921	44,033	10.50	4,194	4.5
2018	37,293.50	8,702	8,472	0.2272	28,822	11.50	2,506	3.5
2019	53,306.88	8,884	8,650	0.1623	44,657	12.50	3,573	2.5
2020	356,250.74	35,625	34,683	0.0974	321,567	13.50	23,820	1.5
2021	48,827.31	1,628	1,585	0.0325	47,243	14.50	3,258	0.5
TOTAL	2,130,095.89	1,006,971	980,352		1,149,744		144,983	

COMPOSITE ANNUAL ACCRUAL RATE	6.81%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.46
COMPOSITE AVERAGE AGE (YEARS)	7.09
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.91

MDU Common

Account #: 391.30 - Computer Equipment - PC

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	475,481.03	427,933	347,848	0.7316	127,633	0.50	127,633	4.5
2018	961,371.69	672,960	547,019	0.5690	414,352	1.50	276,235	3.5
2019	495,525.06	247,763	201,395	0.4064	294,130	2.50	117,652	2.5
2020	1,420,457.68	426,137	346,388	0.2439	1,074,070	3.50	306,877	1.5
2021	285,966.55	28,597	23,245	0.0813	262,722	4.50	58,383	0.5
TOTAL	3,638,802.01	1,803,390	1,465,895		2,172,907		886,780	

COMPOSITE ANNUAL ACCRUAL RATE	24.37%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.40
COMPOSITE AVERAGE AGE (YEARS)	2.48
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.52

MDU Common

Account #: 391.50 - Computer Equipment - Other

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	260,962.58	234,866	191,278	0.7330	69,684	0.50	69,684	4.5
2018	223,116.29	156,181	127,196	0.5701	95,920	1.50	63,947	3.5
2019	656,663.26	328,332	267,397	0.4072	389,266	2.50	155,706	2.5
2020	904,563.36	271,369	221,006	0.2443	683,557	3.50	195,302	1.5
TOTAL	2,045,305.49	990,748	806,878		1,238,428		484,639	

COMPOSITE ANNUAL ACCRUAL RATE 23.70%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.39

COMPOSITE AVERAGE AGE (YEARS) 2.42

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 2.58

MDU Common

Account #: 392.10 - Transportation Equipment - Trailers

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: R1
ASL: 25
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	7,414.01	1,857	1,828	0.2900	4,474	17.63	254	10.5
2012	8,585.60	1,955	1,924	0.2637	5,374	18.30	294	9.5
2013	2,482.58	508	500	0.2371	1,610	18.98	85	8.5
TOTAL	18,482.19	4,321	4,252		11,458		633	

COMPOSITE ANNUAL ACCRUAL RATE	3.42%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	9.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.12

MDU Common

Account #: 392.20 - Transportation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 10
Net Salvage: 20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	12,889.32	8,700	6,380	0.6187	3,932	1.56	2,515	19.5
2007	26,914.31	16,167	11,856	0.5506	9,676	2.49	3,883	14.5
2010	38,523.34	21,013	15,409	0.5000	15,409	3.18	4,843	11.5
2011	186,957.73	99,052	72,638	0.4857	76,928	3.38	22,777	10.5
2012	333,845.03	171,905	126,064	0.4720	141,012	3.56	39,572	9.5
2013	168,225.10	83,656	61,348	0.4558	73,233	3.78	19,353	8.5
2014	598,467.61	282,723	207,330	0.4330	271,444	4.09	66,289	7.5
2015	926,067.25	404,588	296,698	0.4005	444,156	4.54	97,855	6.5
2016	1,374,862.37	535,713	392,857	0.3572	707,033	5.13	137,840	5.5
2017	851,173.46	282,506	207,171	0.3042	473,767	5.85	80,969	4.5
2018	961,071.79	255,519	187,380	0.2437	581,477	6.68	87,091	3.5
2019	1,845,860.99	358,718	263,060	0.1781	1,213,629	7.57	160,304	2.5
2020	994,864.15	118,052	86,572	0.1088	709,320	8.52	83,285	1.5
2021	233,226.92	9,313	6,830	0.0366	179,752	9.50	18,920	0.5
TOTAL	8,552,949.37	2,647,624	1,941,593		4,900,766		825,496	

COMPOSITE ANNUAL ACCRUAL RATE	9.65%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	4.58
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.13

MDU Common

Account #: 393.00 - Stores Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1995	10,272.04	9,074	10,231	0.9960	41	3.50	12	26.5
1999	9,502.32	7,127	8,036	0.8456	1,467	7.50	196	22.5
2000	12,486.01	8,948	10,089	0.8081	2,397	8.50	282	21.5
2007	4,385.78	2,120	2,390	0.5450	1,996	15.50	129	14.5
2014	41,481.25	10,370	11,693	0.2819	29,788	22.50	1,324	7.5
2017	15,127.75	2,269	2,559	0.1691	12,569	25.50	493	4.5
2018	15,273.31	1,782	2,009	0.1315	13,264	26.50	501	3.5
2019	22,339.62	1,862	2,099	0.0940	20,241	27.50	736	2.5
2020	13,367.66	668	754	0.0564	12,614	28.50	443	1.5
2021	30,283.24	505	569	0.0188	29,714	29.50	1,007	0.5
TOTAL	174,518.98	44,725	50,428		124,091		5,123	

COMPOSITE ANNUAL ACCRUAL RATE	2.94%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	7.69
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	22.31

MDU Common

Account #: 394.10 - Tools, Shop & Garage Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	46,034.92	40,281	46,035	1.0000	0	2.50	0	17.5
2005	30,657.04	25,292	30,657	1.0000	0	3.50	0	16.5
2006	34,082.71	26,414	34,083	1.0000	0	4.50	0	15.5
2007	15,616.53	11,322	15,617	1.0000	0	5.50	0	14.5
2008	46,070.14	31,097	46,070	1.0000	0	6.50	0	13.5
2009	6,617.89	4,136	6,618	1.0000	0	7.50	0	12.5
2010	29,472.55	16,947	29,473	1.0000	0	8.50	0	11.5
2011	64,949.37	34,098	64,949	1.0000	0	9.50	0	10.5
2012	39,091.97	18,569	39,092	1.0000	0	10.50	0	9.5
2013	33,002.84	14,026	33,003	1.0000	0	11.50	0	8.5
2014	97,204.70	36,452	97,205	1.0000	0	12.50	0	7.5
2015	68,621.75	22,302	68,622	1.0000	0	13.50	0	6.5
2016	42,870.94	11,790	24,282	0.5664	18,589	14.50	1,282	5.5
2017	120,692.81	27,156	49,697	0.4118	70,996	15.50	4,580	4.5
2018	25,947.90	4,541	8,310	0.3203	17,638	16.50	1,069	3.5
2019	27,070.16	3,384	6,192	0.2288	20,878	17.50	1,193	2.5
2020	11,763.56	882	1,615	0.1373	10,149	18.50	549	1.5
2021	19,751.73	494	904	0.0458	18,848	19.50	967	0.5
TOTAL	759,519.51	329,182	602,422		157,098		9,640	

COMPOSITE ANNUAL ACCRUAL RATE	1.27%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.79
COMPOSITE AVERAGE AGE (YEARS)	8.67
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.33

MDU Common

Account #: 394.30 - Vehicle Maintenance Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	9,575.67	8,857	8,858	0.9251	718	1.50	478	18.5
2004	3,101.37	2,714	2,714	0.8750	388	2.50	155	17.5
2006	8,048.09	6,237	6,237	0.7750	1,811	4.50	402	15.5
2007	25,864.74	18,752	18,752	0.7250	7,113	5.50	1,293	14.5
TOTAL	46,589.87	36,560	36,561		10,028		2,328	

COMPOSITE ANNUAL ACCRUAL RATE 5.00%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.78

COMPOSITE AVERAGE AGE (YEARS) 15.69

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 4.31

MDU Common

Account #: 394.40 - Vehicle Refueling Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	3,814.65	3,147	3,815	1.0000	0	3.50	0	16.5
TOTAL	3,814.65	3,147	3,815		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	16.50
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	3.50

MDU Common

Account #: 397.10 - Radio Communications Equipment - Fixed

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	6,750.02	6,525	6,334	0.9383	416	0.50	416	14.5
2008	25,327.84	22,795	22,127	0.8736	3,201	1.50	2,134	13.5
2009	678,246.85	565,206	548,639	0.8089	129,608	2.50	51,843	12.5
2010	67,374.52	51,654	50,140	0.7442	17,235	3.50	4,924	11.5
2011	91,653.20	64,157	62,277	0.6795	29,376	4.50	6,528	10.5
2012	27,015.84	17,110	16,609	0.6148	10,407	5.50	1,892	9.5
2013	155,578.42	88,161	85,577	0.5501	70,001	6.50	10,769	8.5
2014	184,685.25	92,343	89,636	0.4853	95,049	7.50	12,673	7.5
2015	54,109.51	23,447	22,760	0.4206	31,349	8.50	3,688	6.5
2016	92,224.08	33,816	32,824	0.3559	59,400	9.50	6,253	5.5
2017	127,555.40	38,267	37,145	0.2912	90,410	10.50	8,611	4.5
2018	158,855.85	37,066	35,980	0.2265	122,876	11.50	10,685	3.5
2019	140,371.08	23,395	22,709	0.1618	117,662	12.50	9,413	2.5
2020	345,707.09	34,571	33,557	0.0971	312,150	13.50	23,122	1.5
2021	298,839.12	9,961	9,669	0.0324	289,170	14.50	19,943	0.5
TOTAL	2,454,294.07	1,108,474	1,075,983		1,378,311		172,894	

COMPOSITE ANNUAL ACCRUAL RATE	7.04%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.44
COMPOSITE AVERAGE AGE (YEARS)	6.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.23

MDU Common

Account #: 397.20 - Radio Communications Equipment - Mobile

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	1,255.68	1,214	1,189	0.9473	66	0.50	66	14.5
2008	95,101.86	85,592	83,851	0.8817	11,251	1.50	7,501	13.5
2009	265,292.40	221,077	216,581	0.8164	48,711	2.50	19,485	12.5
2010	61,810.83	47,388	46,425	0.7511	15,386	3.50	4,396	11.5
2011	56,091.35	39,264	38,465	0.6858	17,626	4.50	3,917	10.5
2012	64,821.15	41,053	40,218	0.6205	24,603	5.50	4,473	9.5
2013	51,295.64	29,068	28,476	0.5551	22,819	6.50	3,511	8.5
2014	97,289.52	48,645	47,655	0.4898	49,634	7.50	6,618	7.5
2015	232,388.11	100,702	98,654	0.4245	133,735	8.50	15,733	6.5
2016	72,591.10	26,617	26,075	0.3592	46,516	9.50	4,896	5.5
2017	44,636.05	13,391	13,118	0.2939	31,518	10.50	3,002	4.5
2018	11,664.67	2,722	2,666	0.2286	8,998	11.50	782	3.5
2020	15,034.10	1,503	1,473	0.0980	13,561	13.50	1,005	1.5
TOTAL	1,069,272.46	658,235	644,848		424,424		75,385	

COMPOSITE ANNUAL ACCRUAL RATE	7.05%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.60
COMPOSITE AVERAGE AGE (YEARS)	9.23
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.77

MDU Common

Account #: 397.30 - General Telephone Communication Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	22,514.99	21,389	20,349	0.9038	2,166	0.50	2,166	9.5
2013	368,021.74	312,818	297,602	0.8087	70,420	1.50	46,947	8.5
2014	48,423.02	36,317	34,551	0.7135	13,872	2.50	5,549	7.5
2015	145,186.63	94,371	89,781	0.6184	55,406	3.50	15,830	6.5
2017	97,398.06	43,829	41,697	0.4281	55,701	5.50	10,127	4.5
TOTAL	681,544.44	508,725	483,979		197,565		80,619	

COMPOSITE ANNUAL ACCRUAL RATE	11.83%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.71
COMPOSITE AVERAGE AGE (YEARS)	7.46
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.54

MDU Common

Account #: 397.50 - Supervisory & Telemetering Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	3,111.92	2,956	1,954	0.6280	1,158	0.50	1,158	9.5
2013	10,073.86	8,563	5,660	0.5619	4,413	1.50	2,942	8.5
2021	2,517.81	126	83	0.0331	2,435	9.50	256	0.5
TOTAL	15,703.59	11,645	7,698		8,006		4,356	

COMPOSITE ANNUAL ACCRUAL RATE 27.74%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.49

COMPOSITE AVERAGE AGE (YEARS) 7.42

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 2.58

MDU Common

Account #: 397.80 - Network Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	7,670.26	6,903	5,113	0.6666	2,557	0.50	2,557	4.5
2018	8,414.86	5,890	4,363	0.5184	4,052	1.50	2,702	3.5
2019	332,413.29	166,207	123,097	0.3703	209,316	2.50	83,726	2.5
2020	25,144.25	7,543	5,587	0.2222	19,557	3.50	5,588	1.5
2021	14,293.86	1,429	1,059	0.0741	13,235	4.50	2,941	0.5
TOTAL	387,936.52	187,973	139,218		248,718		97,514	

COMPOSITE ANNUAL ACCRUAL RATE	25.14%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	2.42
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.58

MDU Common

Account #: 398.00 - Miscellaneous Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2021

ALG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	49,732.75	38,792	49,733	1.0000	0	5.50	0	19.5
2003	14,581.60	10,790	14,582	1.0000	0	6.50	0	18.5
2004	19,429.45	13,601	18,626	0.9587	803	7.50	107	17.5
2005	11,868.04	7,833	10,282	0.8664	1,586	8.50	187	16.5
2006	230,098.97	142,661	187,273	0.8139	42,826	9.50	4,508	15.5
2007	14,821.03	8,596	11,284	0.7614	3,537	10.50	337	14.5
2008	48,220.36	26,039	34,182	0.7089	14,039	11.50	1,221	13.5
2010	74,799.68	34,408	45,167	0.6038	29,632	13.50	2,195	11.5
2011	31,820.28	13,365	17,544	0.5513	14,277	14.50	985	10.5
2012	385,182.19	146,369	192,140	0.4988	193,042	15.50	12,454	9.5
2013	44,771.16	15,222	19,982	0.4463	24,789	16.50	1,502	8.5
2014	123,724.15	37,117	48,724	0.3938	75,000	17.50	4,286	7.5
2015	10,522.97	2,736	3,592	0.3413	6,931	18.50	375	6.5
2016	8,540.63	1,879	2,467	0.2888	6,074	19.50	311	5.5
2017	12,051.42	2,169	2,848	0.2363	9,204	20.50	449	4.5
2018	21,759.78	3,046	3,999	0.1838	17,761	21.50	826	3.5
2019	170,767.52	17,077	22,417	0.1313	148,351	22.50	6,593	2.5
2020	67,708.05	4,062	5,333	0.0788	62,375	23.50	2,654	1.5
2021	203,213.70	4,064	5,335	0.0263	197,879	24.50	8,077	0.5
TOTAL	1,543,613.73	529,827	695,508		848,105		47,067	

COMPOSITE ANNUAL ACCRUAL RATE	3.05%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	8.58
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.42

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[3]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

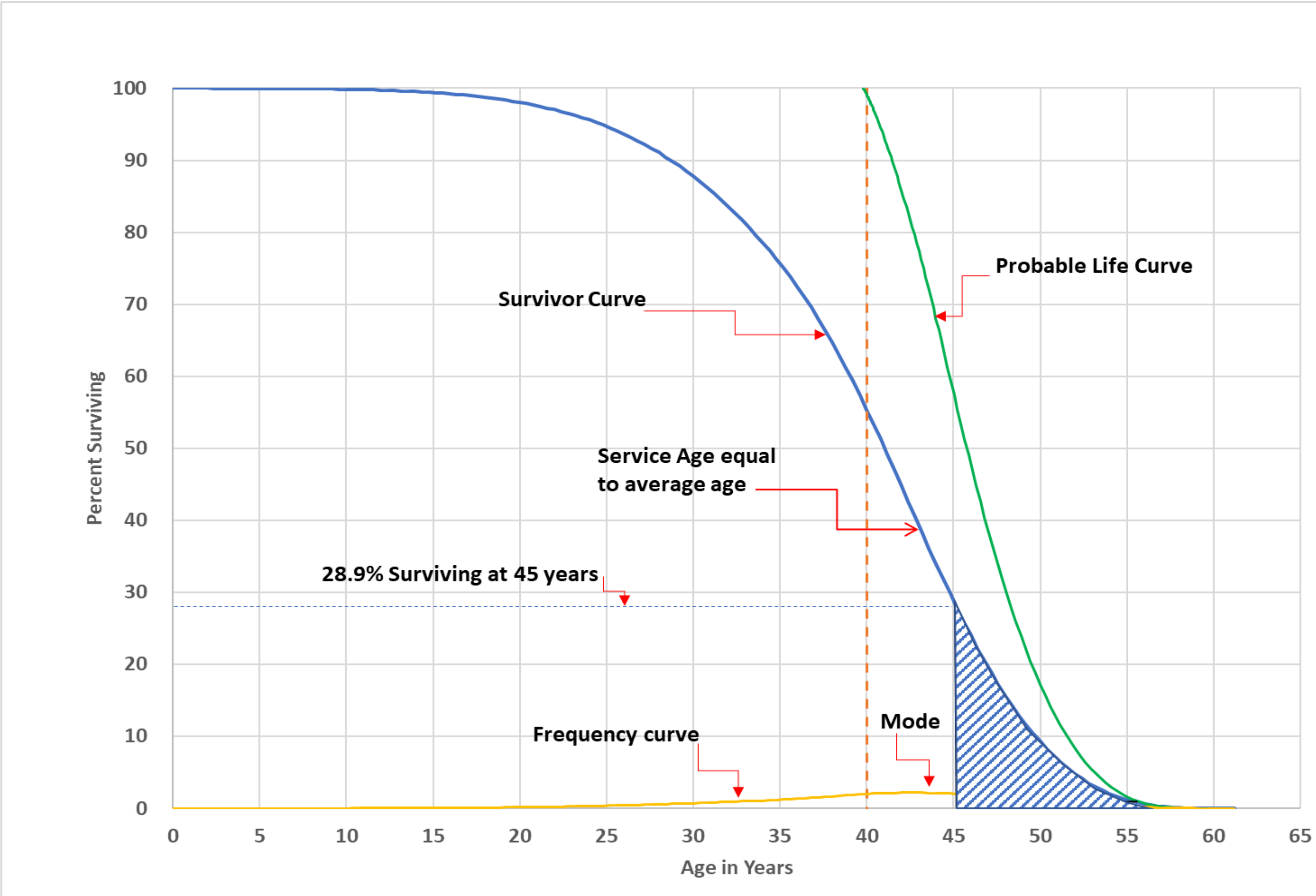
9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age"[4]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[5] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[6]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[3] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[4] *Ibid*, 23.
[5] *Ibid*, 29.
[6] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[7]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[8]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[9] presenting his development of the fourth family consisting of the four O-type survivor curves.

[7] *Ibid*, 21

[8] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[9] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

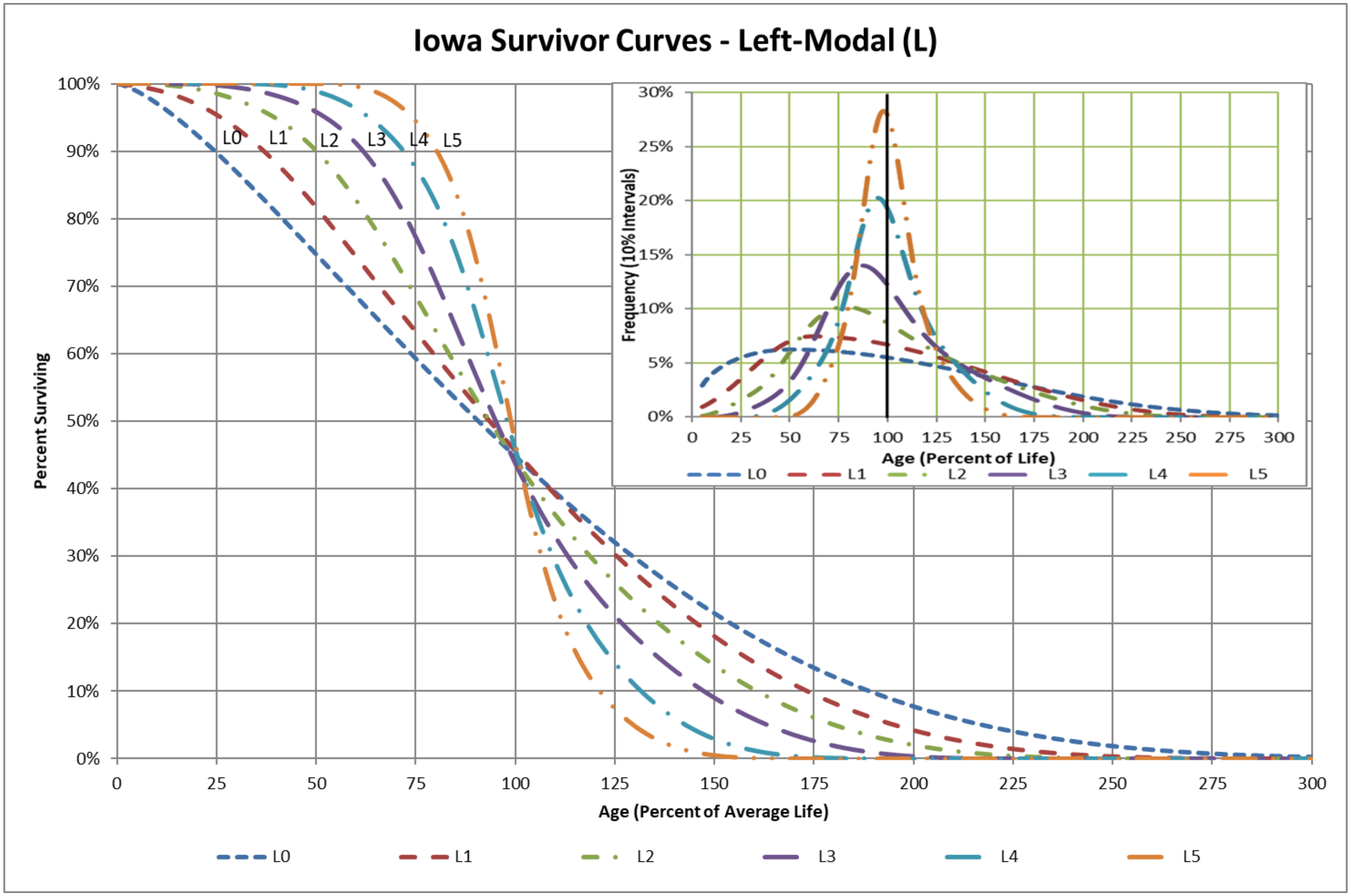


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

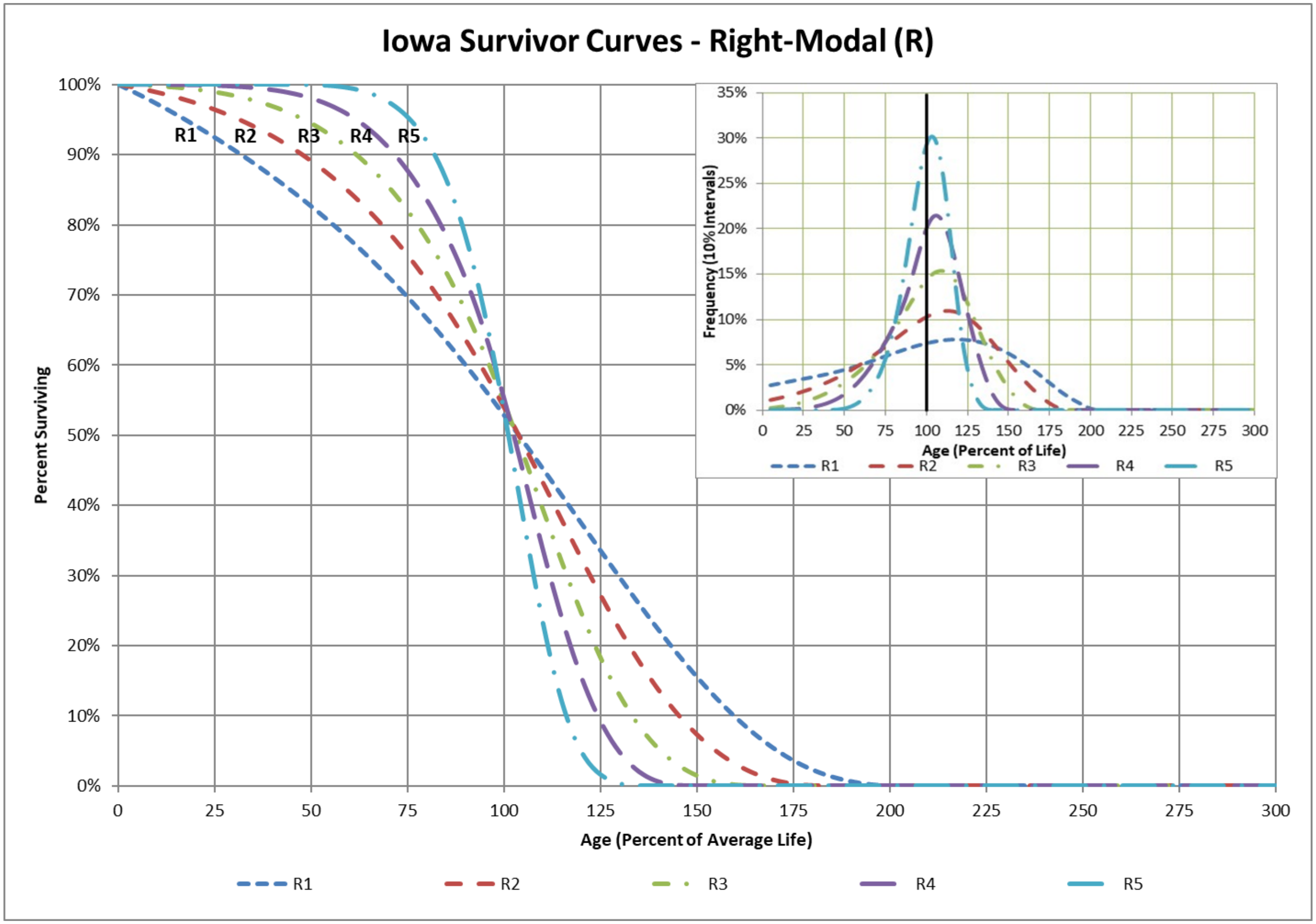


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

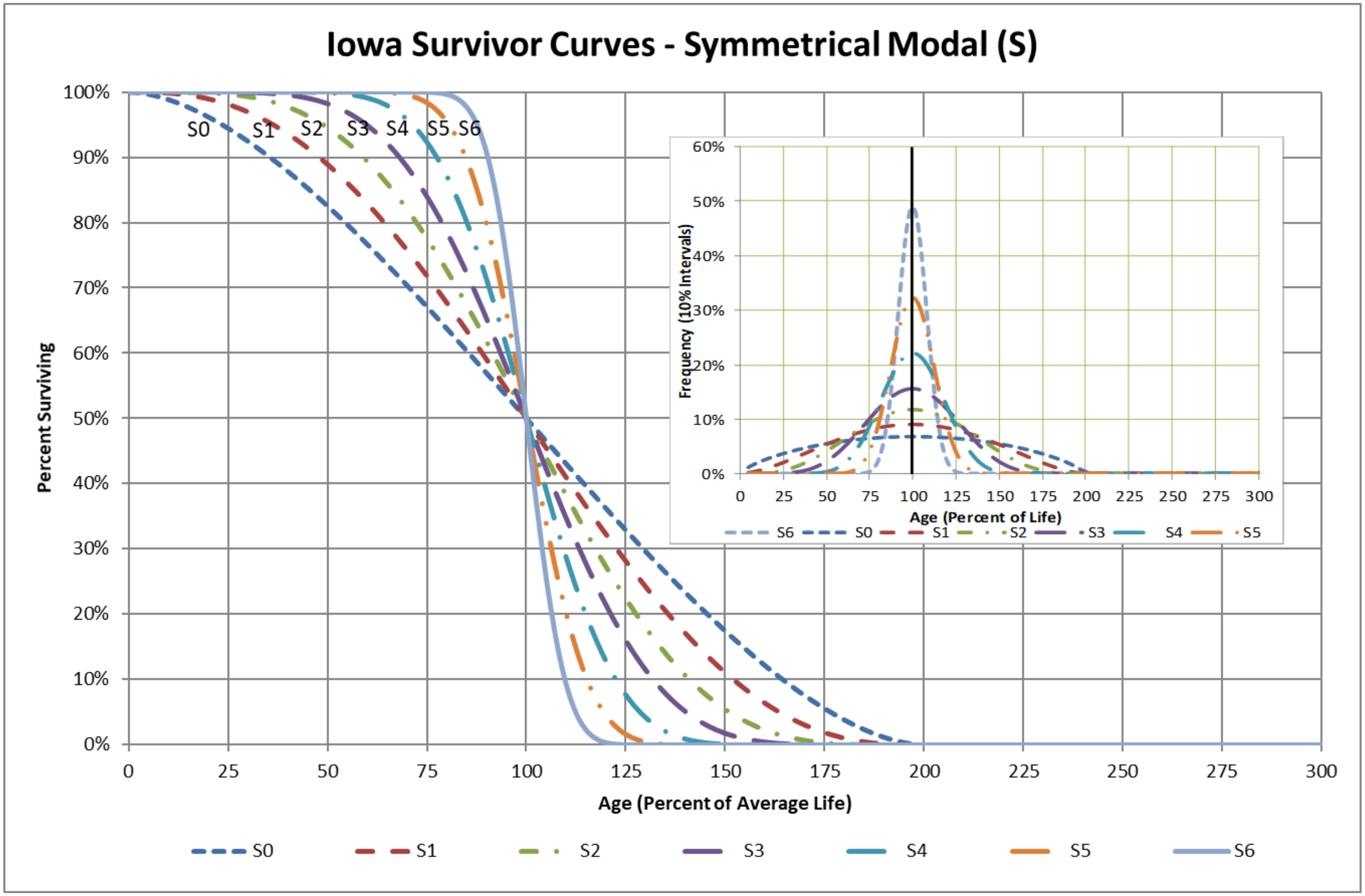
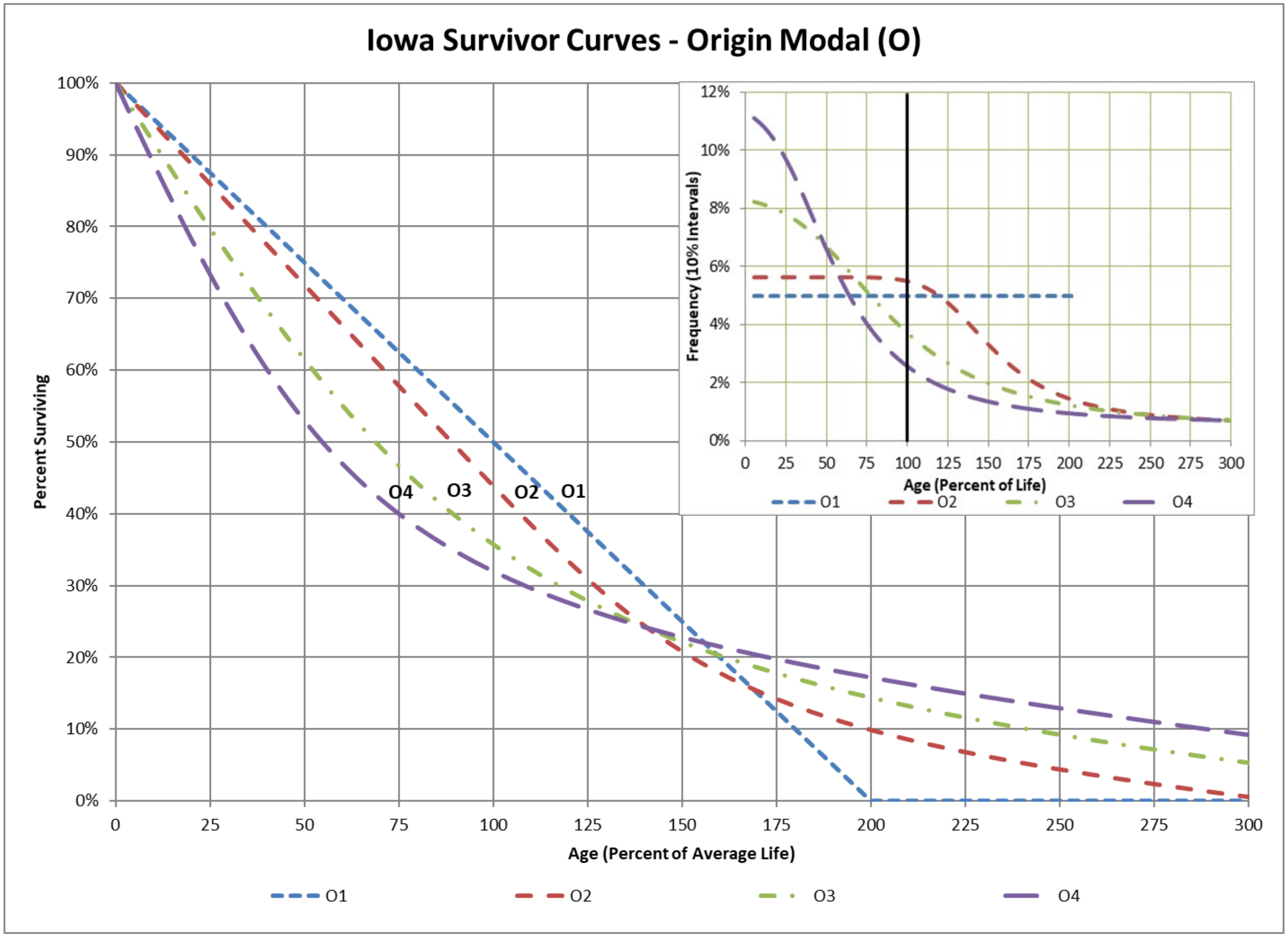


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[10] Engineering Valuation and Depreciation[11] and Depreciation Systems[12].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[10] Anson, Winfrey & Hempstead, supra note 7
[11] Anson, Winfrey & Hempstead, supra note 7
[12] Wolf & Fitch, supra note 2

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017 | Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

	1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
	420	460	510	580	660	750	850	960	1080	1220	0
	1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					Placement Band 2003-2017
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

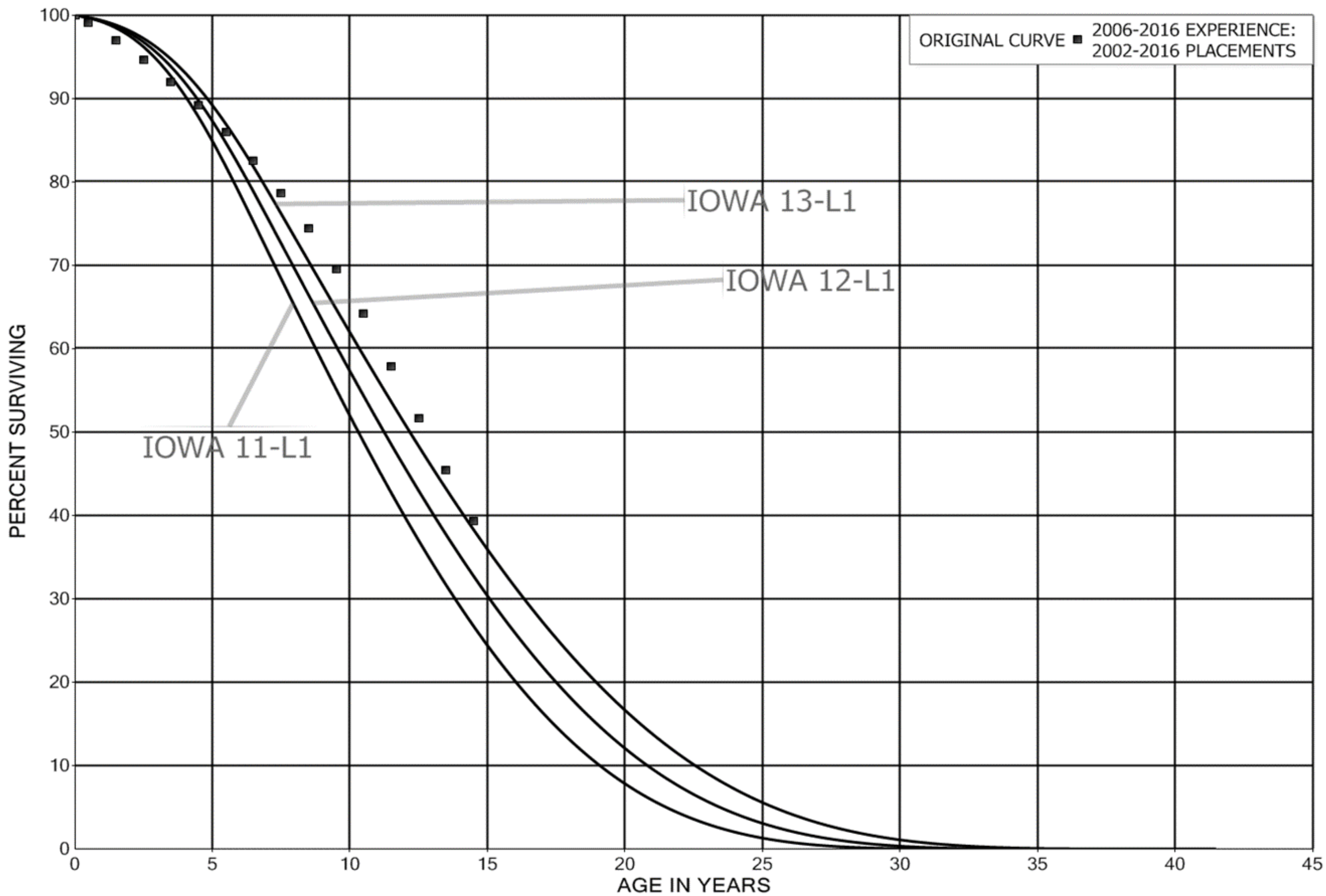


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

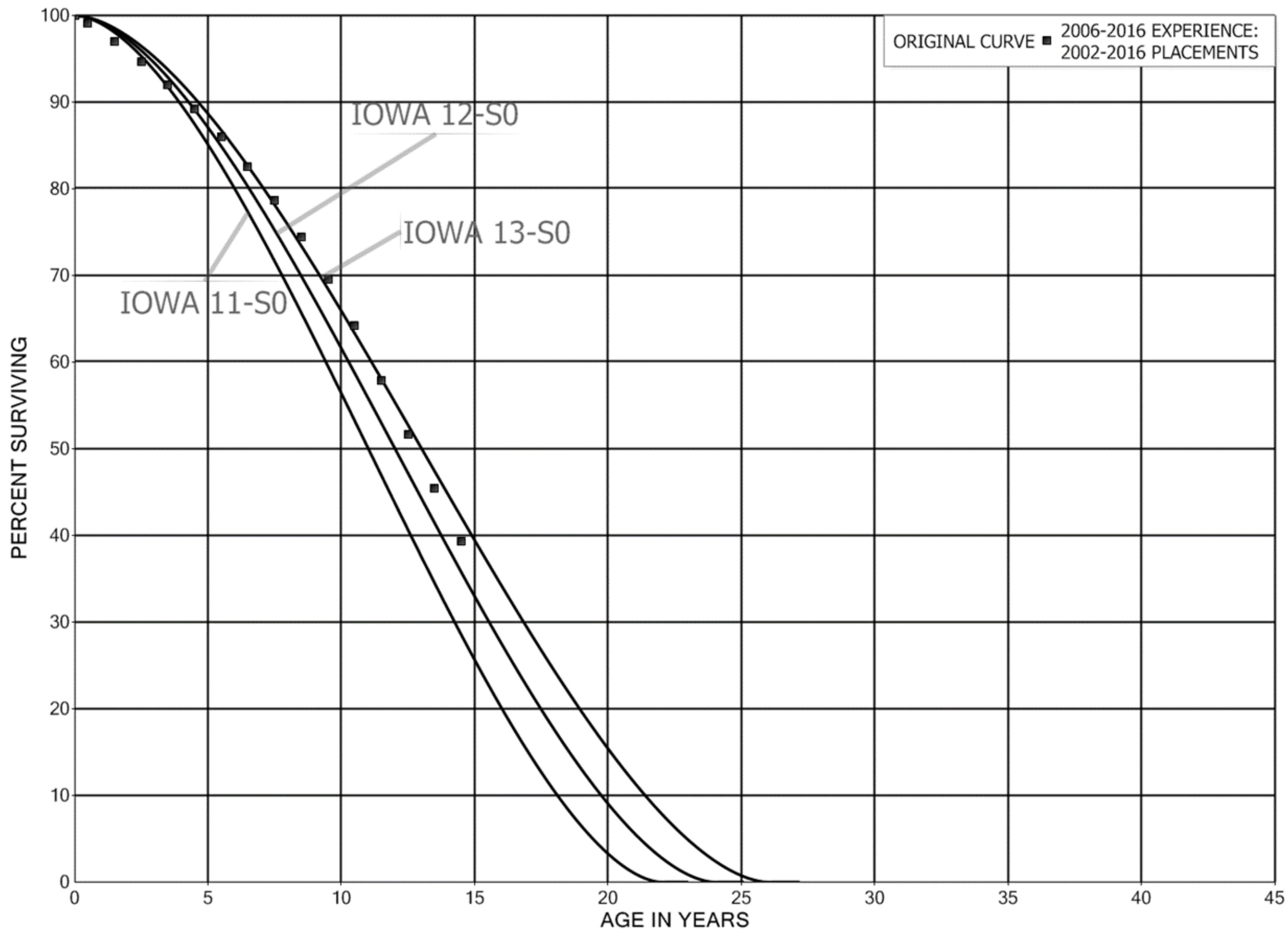


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

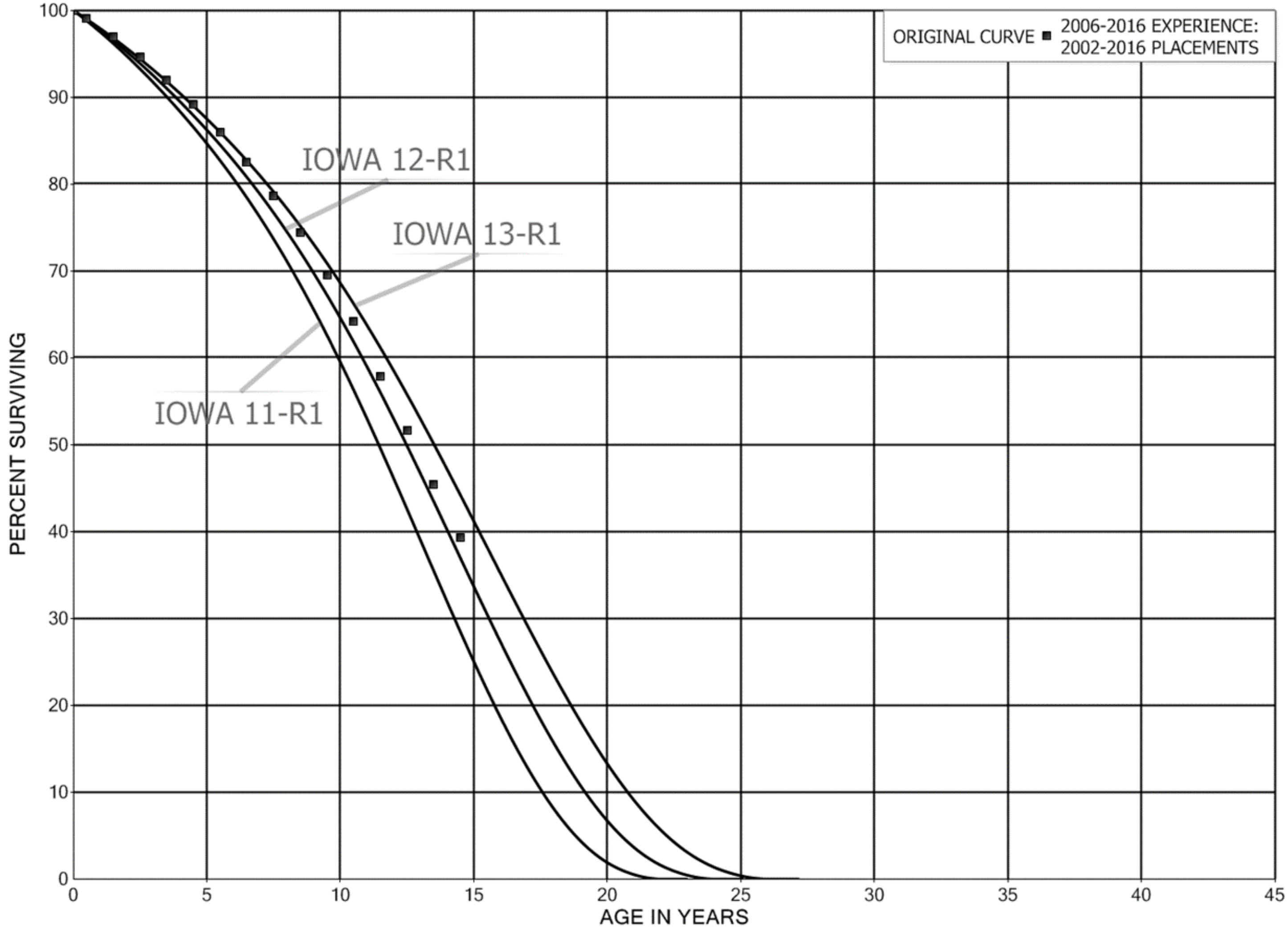
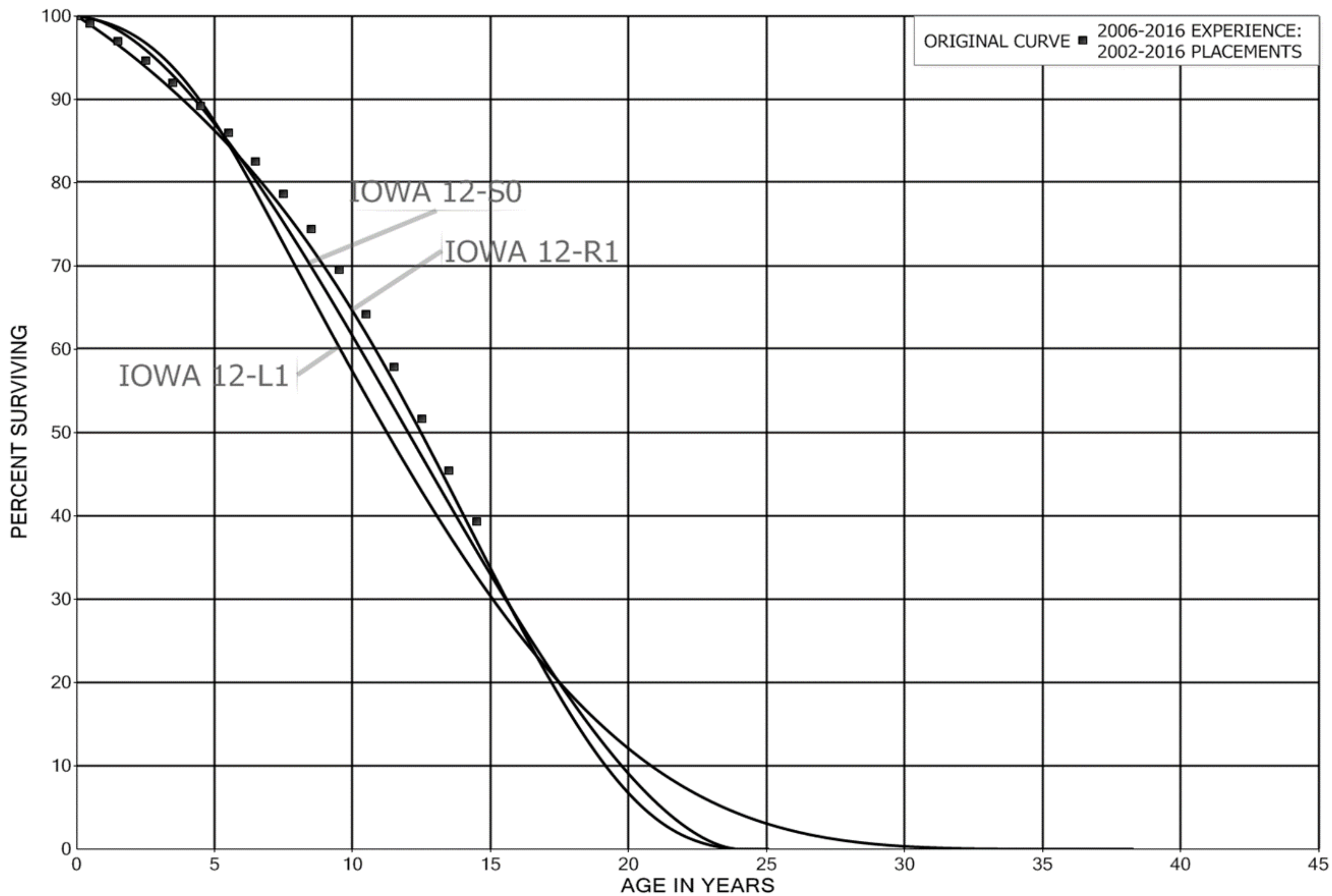


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to Canadian peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account. Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated are usually determined using the “Traditional Approach” for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account’s original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to Canadian peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and Canadian peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-___

Direct Testimony and Exhibits

of

Michael J. Adams

Cash Working Capital / Lead-Lag Study

August 15, 2023

TABLE OF CONTENTS

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael Adams. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Senior Vice President with Concentric Energy Advisors, Inc. ("Concentric").

Q. PLEASE DESCRIBE CONCENTRIC.

A. Concentric is a management consulting and economic advisory firm focused on the North American energy and water industries. Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As a consultant, my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. PLEASE DESCRIBE YOUR EDUCATION.

A. I have an MBA from the University of Illinois – Springfield and a Bachelor of Science degree in Accounting from Illinois College. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

A. I have over thirty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements. A statement of my background and qualifications is attached as Exhibit MJA-1.

Q. HAVE YOU EVER TESTIFIED IN A REGULATORY PROCEEDING?

A. Yes. I have provided expert testimony or reports before the Arizona Corporation Commission; Arkansas Public Service Commission; the City of El Paso; the Connecticut Public Utilities Regulatory Authority, the Federal Energy Regulatory Commission (FERC); the Georgia Public Service Commission; the Hawaii Public Utility Commission; the Idaho Public Utilities Commission; the Illinois Commerce Commission; the Maine Public Utilities Commission; the Maryland Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Missouri Public Service Commission; the Montana Public Service Commission, the New Hampshire Public Utilities Commission; the New Mexico Public Regulation Commission; the State of New Jersey Board of Public Utilities; the Oklahoma Corporation Commission; the Ontario Energy Board; the Pennsylvania Public Utility Commission; the Tennessee Public Utility

Commission; the Public Utility Commission of Texas; the State Corporation Commission of Virginia; and the Public Service Commission of West Virginia.

My testimonies typically address issues related to cost of service/revenue requirement, shared services, accounting and/or cost allocations.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I have been asked by Montana-Dakota Utilities Co. ("MDU" or the "Company") to discuss a lead-lag study that was used to develop cash working capital ("CWC") factors and ultimately to calculate the cash working capital requirements of the Company's South Dakota gas operations. Discussion of the study follows.

III. Cash Working Capital Requirement and Lead-Lag Study

Q. PLEASE DEFINE WHAT YOU MEAN BY THE PHRASE "CASH WORKING CAPITAL."

A. Cash working capital is the amount of funds the Company is required to maintain on hand to finance the day-to-day operations of the Company.

Q. ARE YOU SPONSORING AN EXHIBIT IN THIS PROCEEDING RELATED TO YOUR ANALYSIS OF CASH WORKING CAPITAL?

A. Yes. Exhibit MJA-2 has been prepared under my direction and supervision and is accurate and complete to the best of my knowledge and belief. Specifically, the Exhibit summarizes the revenue lag and the various expense leads supported by the lead-lag study pertaining to the Company's gas operations.

Q. FOR WHAT PERIOD WAS THE LEAD-LAG STUDY PERFORMED?

A. The lead-lag study analyzed the Company's cash transactions and invoices for the twelve months ended December 31, 2022. The leads and lags were applied to expense amounts for the Test Year.

Q. HOW SHOULD THE RESULTS OF THE CASH WORKING CAPITAL ANALYSIS BE TREATED FOR RATEMAKING PURPOSES?

A. The cash working capital requirements should be included as part of MDU South Dakota's gas operations rate base for ratemaking purposes.

Q. IS THE ANALYSIS OF THE REVENUE LAGS AND EXPENSE LEADS TYPICALLY REFERRED TO AS A LEAD-LAG STUDY?

A. Yes. Cash working capital requirements are generally determined by lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date. The "leads" and "lags" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is then included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied in this proceeding are described in the testimony of Company witness Vesey.

Q. WHAT ARE THE VARIOUS LEADS AND LAGS THAT WERE CONSIDERED IN THE CASH WORKING CAPITAL ANALYSIS?

A. Two broad categories of leads and lags were considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company, as well as the various taxes and other expenses paid by the Company ("expense leads").

Q. WHAT IS A REVENUE LAG?

A. A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., gas) and its ability to use the funds received as payment for the delivery of the product.

Q. WHAT IS AN EXPENSE LEAD?

A. The expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Q. WHAT WAS THE SOURCE OF INFORMATION YOU EMPLOYED TO DETERMINE THE LEADS AND LAGS IN YOUR CASH WORKING CAPITAL ANALYSIS?

A. Information from the Company was utilized, including data from their Accounts Receivable, Accounts Payable, Customer Service, Human Resources, Payroll, and Tax systems. The information derived from these sources, together with analyses of specific transactions, led to the determination of the appropriate number of lead-lag days for MDU's South Dakota gas operations.

A. Revenue Lag

Q. HOW WAS THE REVENUE LAG DETERMINED?

A. The revenue lag measures the number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited and available to the Company. In the calculation, the revenue lag was divided into five distinct components: 1) service lag; 2) billing lag; 3) collections lag; 4) payment processing; and 5) bank float. An explanation of each component of the revenue lag follows.

Q. WHAT IS MEANT BY SERVICE LAG?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for that service period. Using the mid-point methodology, the average lag associated with the provisioning of service was 15.21 days (365 days in the year divided by 12 months divided by 2).

Q. WHAT IS MEANT BY BILLING LAG?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's monthly billing schedules and meter reading records. The average billing lag was conservatively determined to be 1.00 day.

Q. WHAT IS MEANT BY COLLECTIONS LAG?

A. The collections lag refers to the average amount of time from the date when the customer received a bill to the date that the Company received payment from its customers. For purposes of the cash working capital analyses, the Company's actual customer receivables during the twelve months ended December 31, 2022 were analyzed to determine the collections lag. Based on weighted average data from the Company and by considering accounts receivables balances by days aged, the average collection lag was determined to be 23.86 days.

Q. EXPLAIN THE COMPANY'S CALCULATION OF THE COLLECTION LAG.

A. The monthly accounts receivable data was categorized into aging "buckets" of 0-30 days, 30-60 days, 60-90 days, 90-120 days and 120+ days. For purposes of calculating the collection lag, it was assumed the customers will pay their bills ratably over the month. Therefore, the midpoint of the first month was determined to be 15 days (*i.e.*, 30 divided by 2). I applied the same assumption that customers will pay their bills ratably over the course of the month to each aging bucket. It was further assumed that customers will pay their bills ratably over the course of the second month (the month that is 30-60 days after the bill was issued). Therefore, the midpoint of payments that are received 30-60 days after the bill is issued is 45 days (*i.e.*, 30 days outstanding from the first month plus the 15-day midpoint of the second month = 45 days). This same theory applies to the use of 75 days for payments that were received 60-90 days after the bill is issued as well as the use of 105 days for the 90-120 days period. Receivables outstanding for 120 days or longer were conservatively capped at 120 days. The accounts receivable dollars in each bucket were then multiplied by the midpoint of each bucket to calculate the collections lag.

Q. WHAT IS MEANT BY PAYMENT PROCESSING?

A. The payment processing lag refers to the period of elapsed time from the Company's receipt of the customer's funds until the point in time when the customer's payments have been processed and sent to the Company's bank for deposit. The payment processing lag, which was determined based upon an analysis of the various methods of payments used by the Company's customers to pay their bills, and the availability of such funds from each method of payment, the payment lag was determined to be 0.59 days.

Q. WHAT IS BANK FLOAT?

A. Bank float reflects the elapsed time from when customer's payments are sent to the bank for deposit and the time when such funds are available to the Company. Bank float data provided by MDU for calendar year 2022 reflects a float time of 0.93 days between the date of deposit and the date MDU had access to the funds.

Q. PLEASE SUMMARIZE THE CALCULATION OF REVENUE LAG DAYS.

A. The overall revenue lag, by lag component, is summarized in the following table.

Revenue Lag by Component	
Service Lag	15.21
Billing Lag	1.00
Collections Lag	23.86
Payment Processing	0.59
Bank Float	0.93
Total Lag	**41.58**

B. Expense Leads

Q. WHAT EXPENSE-RELATED LEADS WERE CONSIDERED IN THE LEAD-LAG ANALYSIS?

A. Lead times associated with the following expense categories were considered in the lead-lag study: a) payroll and withholdings; b) payroll taxes; c) employee benefits; d) other O&M; e) gas costs; f) general taxes other than income taxes; g) federal income taxes; h) interest on long-term debt; and i) short-term interest on commercial paper, notes payable and commitment fees.

Q. PROVIDE AN EXPLANATION OF THE EXPENSE LEAD ASSOCIATED WITH THE COMPANY'S PAYROLL AND WITHHOLDINGS EXPENSES.

A. Considering MDU's various payroll periods (i.e. bi-weekly, monthly, and interim payrolls), as well as incentive compensation and payroll related withholding payments the payroll and withholding expense lead was determined to be 30.42 days.

Q. WHAT PAYROLL RELATED TAXES DOES THE COMPANY PAY?

A. The Company pays the following payroll-related taxes: (1) Federal Unemployment; (2) State Unemployment (Idaho, Minnesota, Montana, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Washington, and Wyoming); (3) Oregon Workers Benefits Fund; and (4) Workers Compensation (North Dakota, Washington, and Wyoming) The dollar-weighted expense lead for all of these taxes was determined to be 22.25 days.

Q. WHAT EMPLOYEE BENEFITS DOES THE COMPANY PROVIDE AND WHAT IS THE EXPENSE LEAD ASSOCIATED WITH SUCH BENEFITS?

A. The Company provides benefits associated with medical, dental, life, long-term disability insurance as well as health savings accounts, employee assistance programs and 401(k) matching. The dollar-weighted expense lead for these benefits was determined to be 12.33 days.

Q. WHAT ARE OTHER O&M EXPENSES AND WHAT LEAD TIMES WERE ASSOCIATED WITH SUCH EXPENSES?

A. The Company engages in transactions with vendors for a variety of purposes including facility maintenance, system maintenance, customer service, as well as other services. Accounts payable data was analyzed in order to calculate a lead time associated with the payment for services related to other operations and maintenance activities. The analysis indicates that on average, invoices were paid by the Company 33.71 days after receipt. This lead time includes a service lead time.

Q. WHAT IS THE EXPENSE LEAD TIME ASSOCIATED WITH THE COMPANY'S FUEL EXPENSES?

A. The Company purchases natural gas for distribution to its gas customers. Based on an examination of the service periods and payment dates for the Company's purchase of natural gas, a weighted expense lead time of 40.31 days was determined.

Q. WHAT ARE THE VARIOUS GENERAL TAXES CONSIDERED IN THE CASH WORKING CAPITAL ANALYSIS?

A. The following general taxes were considered in the study: a) Property Tax; b) Secretary of State; c) Gross Revenue Tax; d) Highway Use Tax; and e) Delaware Franchise Tax.

Q. EXPLAIN THE LEAD EFFECTS ASSOCIATED WITH EACH TYPE OF GENERAL TAXES CONSIDERED IN THE ANALYSIS.

A. The treatment of each category of general taxes in the study is described below:

a) Property Tax: Taking the semi-annual periods for which the tax is assessed, as well as the timing of the actual payment dates and amounts into consideration for the property tax payments, a dollar-weighted expense lead of 398.71 days was determined.

b) Secretary of State - If a company has received authority to do business in a State, the Secretary of State's Office will require an annual or biennial report to be filed by the Company to keep the Company's status in "good standing." If these reports are not filed, the company's authority to do business in that State will be revoked. The dollar-weighted expense lead associated with the Secretary of State Tax was calculated to be negative 49.50 days.

c) Gross Revenue Tax – The tax is for a calendar year period and is due on July 1 of that year (i.e., the tax is prepaid). The dollar-weighted expense lead associated with the Gross Revenue Tax was calculated to be 364.50 days.

d) Highway Use Tax: The heavy highway vehicle use tax is a tax on highway motor vehicles used during the tax period. Taking the annual period for which the tax was assessed, as well as the timing of the actual payment date and amount into consideration for the tax payment, a dollar-weighted expense lead of negative 136.50 days was determined.

e) Delaware Franchise Fee Tax - Montana-Dakota Co. was incorporated in the State of Delaware so this is a franchise fee which is due each year. The tax is based on authorized shares. Based upon the due dates, the expense lead associated with the Delaware Franchise Fee Tax was calculated to be 99.50 days.

Q. **HOW DID YOUR STUDY ADDRESS FEDERAL INCOME TAXES?**

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code that require estimated tax payments of 25 percent of total income taxes due each quarter of the current year. The first quarter payment is due by April 15th, while the second, third, and fourth quarters payments are due on June 15th, September 15th, and December 15th, respectively. Taking this schedule into consideration a lead time of 37.88 days for federal income taxes was determined.

Q. PROVIDE A DESCRIPTION OF HOW LEAD TIMES ASSOCIATED WITH THE COMPANY'S LONG-TERM INTEREST EXPENSES WERE ADDRESSED BY THE STUDY.

A. The Company made semi-annual interest payments on its long-term debt throughout the test year. Using the midpoints of the semi-annual service periods, a dollar-weighted lead of 91.13 days for long-term interest payments was determined.

Q. DID YOU ALSO CALCULATE THE LEAD TIMES ASSOCIATED WITH THE COMPANY'S SHORT-TERM INTEREST EXPENSE?

A. Yes. The Company made periodic interest payments on three different types of short-term debt throughout the test year. The debt instruments included 1) term loan commercial paper; 2) a Minot Air Force Base ("MAFB") note payable associated with the purchase of the gas distribution facilities; and 3) commitment fees paid associated with short-term debt. Using the midpoints of the service periods, a combined dollar-weighted lead of 18.30 days for short-term interest payments was determined.

Q. BASED UPON THE RESULTS OF THE LEAD-LAG STUDY AND THE LEVEL OF EXPENSES SPONSORED BY COMPANY WITNESS VESEY, WHAT LEVEL OF CASH WORKING CAPITAL REQUIREMENTS SHOULD BE INCLUDED IN MDU'S RATE BASE?

A. Adjustment M which is sponsored by MDU witness Vesey, shows the cash working capital requirement that should be included in the Company's rate base.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

MICHAEL J. ADAMS
Senior Vice President

Mr. Adams has over thirty-five years of direct experience in the public utility industry. He has worked for an investor-owned utility, a regulatory agency, and most recently as a consultant to the utility industry.

While employed by Illinois Power Company, Mr. Adams monitored project expenditures associated with gas and electric distribution, transmission, and generation capital projects.

While employed by the Illinois Commerce Commission, Mr. Adams initially evaluated the rate filings of regulated utilities and provided expert testimony regarding the reasonableness of the requests. Mr. Adams was subsequently charged with developing and managing a management and operations audit program to evaluate company management policies, procedures, and performance, as well as operational efficiency and effectiveness. Mr. Adams served as the Deputy Executive Director of the agency at the time of his departure. As a consultant, Mr. Adams has provided consulting services to regulatory agencies and regulated utilities on an array of operational and financial issues since 1995.

Prior to joining Concentric, Mr. Adams was a Managing Director of Navigant Consulting, Inc. Mr. Adams is a Certified Public Accountant, a graduate of Illinois College and holds an M.B.A. from the University of Illinois, Springfield.

Mr. Adams provides financial, regulatory, strategic, operational and litigation support to his energy clients. provides a wide array of services to his energy clients in preparation for, and support of regulatory filings. He has assisted clients with regulatory/legislative initiatives related to the approval and implementation of alternative regulation plans as well as the preparation and support of regulatory filings under alternative rate plans. Mr. Adams also provides advisory services in the areas of mergers and acquisitions. As a consultant, Mr. Adams has provided expert testimony or reports before State and Federal regulatory agencies.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc.

Senior Vice President

Vice President

Navigant Consulting, Inc.

Managing Director

L.E. Burgess Consultants, Inc.

Illinois Commerce Commission

Accounting/Rate Case Staff

Director, Management Audit/Studies

Deputy Executive Director

Illinois Power Company

Accounting/Auditing Department

EDUCATION

University of Illinois at Springfield

M.B.A., Finance

Illinois College

B.S., Accounting

REPRESENTATIVE PROJECT EXPERIENCE

AUDITS/SPECIAL STUDIES

- Management audits
- Regulatory reviews/audits
- Project performance monitoring/reviews
- Prudence reviews
- A&G Capitalization Studies
- Commission ordered studies
- Audit prep and support
- Project controls and assessments

Affiliate Transactions

- Code of Conduct
- Shared Services reviews
- Cost controls

Benchmarking

- O&M costs
- Capital expenditures
- Shared Services

- Operational performance
- Customer service
- Reliability

DUE DILIGENCE/LITIGATION/SPECIAL PROJECTS

- Assessment of cost controls
- Financial outlook
- Historical/future performance assessment
- Merger Synergies
- Regulatory environment/assessment

EXPERT WITNESS

- Regulatory proceedings
- Civil litigation

LITIGATION SUPPORT

- Data review and analyses
- Position development and review
- Research
- Expert testimony and reports

REGULATORY PROCEEDINGS

- Revenue Requirement
- Cash working capital
- Benchmarking
  - O&M
  - Capital
  - Shared Services
- Case development/management
- Multi-year rate plans
- Research
- Performance based regulation

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant

American Institute of Public Accountants

Illinois Society of Certified Public Accountants

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arizona Corporation Commission				
Liberty Utilities	2022	Liberty Utilities	SW-04316A-21-0325, SW-02519A-21-0326, SW-04316A-21-0359	Capitalization rate for indirect overheads
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	2002	Arkansas Oklahoma Gas Corporation	02-024-U	Reasonableness of ratemaking adjustments
Centerpoint Energy Arkla	2005	Centerpoint Energy Arkla	04-121-U	Cash Working Capital
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas	2013	Connecticut Natural Gas	13-06-08	Cash Working Capital
United Illuminating Company	2022	United Illuminating Company	22-08-08	Cash Working Capital
Federal Energy Regulatory Commission				
Granite State Gas Transmission	2010	Granite State Gas Transmission	RP10-896	Revenue Requirement
Georgia Public Service Commission				
Atlanta Gas Light Company	2019	Granite State Gas Transmission	42315	Cash Working Capital
Hawaii Public Utilities Commission				
Hawaii Electric Light Company, Inc.	2005	Hawaii Electric Light Company, Inc.	05-0315	Allowance for Funds Used During Construction
Idaho Public Utilities Commission				
Intermountain Gas Company	2016	Intermountain Gas Company	INT-G-16-2	Cash working capital, prepared/supported benchmarking for client
Illinois Commerce Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Power Company	1999	Illinois Power Company	99-0120/99-0134 (Cons.)	Functionalization/Unbundling of General and Intangible Assets and Administrative and General expenses.
Illinois Power Company	2004	Illinois Power Company	04-0476	Cash working capital and asset separation
Ameren Illinois Utilities	2006	Ameren Illinois Utilities	06-0070/06-0071/06-0072 (Cons.)	Functionalization of Assets, Cash Working Capital, Shared Services Costs, Benchmarking
Ameren Illinois Utilities	2007	Ameren Illinois Utilities	07-0585/07-0586/07-0587/ 07-0588/07-0589/07-0590 (Cons.)	Shared Services Costs, Asset Separation, Cash Working Capital
Commonwealth Edison Company	2022	Commonwealth Edison Company	22-0103	Cash working capital requirements associated with procurement of electric power and energy
The Peoples Gas Light and Coke Company, Inc. and North Shore Gas Company	2007	The Peoples Gas Light and Coke Company, Inc. and North Shore Gas Company	07-0241/07-0242 (Cons.)	Cash working capital
Northern Illinois Gas Company	2008	Northern Illinois Gas Company	08-0363	Cash working capital
Ameren Illinois	2015	Ameren Illinois	16-0262	Benchmarking of Utility Performance
Ameren Illinois	2023	Ameren Illinois	23-0082	Overview of MYRP filings
Maine Public Utilities Commission				
Emera Maine	2017	Emera Maine	Docket No. 2017-00198	Cash working capital
Versant Power	2020	Versant Power	Docket No. 2020-00316	Cash working capital
Versant Power	2022	Versant Power	Docket No. 2022-00255	Cash working capital
Maryland Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Constellation Energy	2009	Constellation Energy	Case No. 9173, Phase II	Shared Services, Benchmarking
Massachusetts Department of Public Utilities				
Massachusetts Distribution Companies	2002	Massachusetts Distribution Companies	DTE-99-84	Reliability standards and the appropriateness of utilizing data for benchmarking purposes
Missouri Public Service Commission				
AmerenUE (Union Electric Company)	2002	AmerenUE (Union Electric Company)	EC-2002-001	Cash working capital
AmerenUE	2003	AmerenUE	GR-2003-0517	Cash working capital
AmerenUE	2007	AmerenUE	ER-2007-0002	Cash working capital
AmerenUE	2008	AmerenUE	ER-2008-0318	Cash working capital
Missouri Gas Energy	2006	Missouri Gas Energy	GR-2006-0422	Cash working capital
Ameren Missouri Gas	2010	Ameren Missouri Gas	GR-2010-0363	Cash working capital
Ameren Missouri Electric	2010	Ameren Missouri Electric	ER-2011-0028	Cash working capital
Ameren Missouri	2012	Ameren Missouri	ER-2012-0166	Cash working capital
Ameren Missouri	2014	Ameren Missouri	ER-2014-0258	Affiliate transactions, Benchmarking
Evergy Metro, Inc. and Evergy Missouri West	2022	Evergy Metro, Inc. and Evergy Missouri West	ER-2022-0129 and ER-2022-130	Cash working capital, Property Tax Tracker
New Hampshire Public Utilities Commission				
National Grid Energy North	2010	National Grid Energy North	DG 10-017	Revenue Requirement
New Mexico Public Utility Regulation Commission				
New Mexico Gas Company	2019	New Mexico Gas Company	19-00317-UT	NMGC’s future test year cost of service model
State of New Jersey Board of Public Utilities				
PSEG	2018	PSEG	ER18010029 & GR18010030	Benchmarking

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	2003	Arkansas Oklahoma Gas Corporation	PUD200300088	Cash working capital
Ontario Energy Board				
Hydro One Distribution Business	2005	Hydro One Distribution Business	-	Cash working capital
Hydro One Transmission Business	2006	Hydro One Transmission Business	-	Cash working capital
Toronto Hydro	2006	Toronto Hydro	-	Cash working capital
Pennsylvania Public Utility Commission				
Allegheny Power	2004	Allegheny Power	M-00991220	Reliability data and reasonableness of established standards
T.W. Phillips Gas and Oil Company, Inc.	2006	T.W. Phillips Gas and Oil Company, Inc.	R-00051178	Cash working capital
Public Utility Commission of Texas				
Texas-New Mexico Power Company	2008	Texas-New Mexico Power Company	36025	Revenue Requirement
El Paso Electric Company	2012	El Paso Electric Company	40094	O&M Benchmarking
El Paso Electric Company	2014	El Paso Electric Company	-	Benchmarking of New Generation Costs
El Paso Electric Company	2015	El Paso Electric Company	44941	Benchmarking of costs of new generation units
Public Service Commission of West Virginia				
Appalachian Power Company	2018	Appalachian Power Company	18-0646-E-42T	Cash Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Tennessee Public Utility Commission				
Chattanooga Gas Company	2018	Chattanooga Gas Company	18-00017	Cash Working Capital
Virginia State Corporation Commission				
Virginia Natural Gas	2012	Virginia Natural Gas	PUE-2010-00142	Cash Working Capital
Virginia Natural Gas	2017	Virginia Natural Gas	-	Shared Services Review, Benchmarking, Cash Working Capital
Virginia Natural Gas	2022	Virginia Natural Gas	PUR-2022-00052	Cash Working Capital

Montana-Dakota Utilities

South Dakota – Gas Operations

Cash Working Capital Leads/Lags

Line No.	Lead/Lag	Days
1	**Revenue Lag**	
2	Service Lag	15.21
3	Billing Lag	1.00
4	Collections Lag	24.72
5	Payment Processing	0.59
6	Bank Float	0.93
7	Total Revenue Lag	41.58
8	**Expense Leads**	
9	Payroll and Withholdings	30.42
10	Payroll Taxes	22.25
11	Employee Benefits	12.33
12	Other O&M Expenses	33.71
13	Fuel	40.31
14	Property Taxes	398.71
15	Gross Revenue Tax	364.50
16	Highway Use Tax	-136.50
17	Secretary of State Tax	-49.50
18	Delaware Franchise Fee Tax	99.50
19	Federal Income Taxes	37.88
20	Interest on Long-Term Debt	91.13
21	Short-Term Interest	18.30

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-____

Direct Testimony

Of

Nathan A. Bensen

Q. Would you please state your name and business address?

A. Yes. My name is Nathan A. Bensen, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am a Senior Regulatory Analyst in the Regulatory Affairs Department for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Would you please describe your duties as a Regulatory Analyst?

A. I assist in the preparation of the annual electric rider filings in North Dakota and South Dakota, weather normalization of natural gas volumes, and other filings required by state commissions.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota with a Bachelor of Accountancy degree. I have been in my current position with Montana-Dakota for six years. Prior to starting in my current role June of 2017, I was employed by the State of North Dakota as an Auditor for sales, use and gross receipts taxes with the Office of the Tax Commissioner; and a Cost Report Auditor with the Department of Health and Human Services.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission and have prepared testimony for the North Dakota Public Service Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the methodology used by Montana-Dakota to forecast natural gas sales data, including weather normalized volumes, pro forma volumes and pro forma customers. The totality of this process and its results are the foundational basis for the underlying pro forma revenues used in this rate case.

Q. What statements, schedules and exhibits are you sponsoring?

A. I am sponsoring the development of the pro forma billing units as presented on Exhibit No. ___(NAB-1) and ultimately used in the pro forma revenues on Rule 20:10:13:85 Statement I. The results presented on Exhibit No. ___(NAB-1) are supported by the regression models included in Workpapers Statement I, pages 2 through 40.

Q. Would you describe the development of the normalized volumes?

A. Natural gas volumes for residential, firm general, and select interruptible and transportation customers were adjusted to reflect normal weather patterns, where appropriate. Each of the aforementioned customer classes were adjusted separately. Billing period sales volumes and customers, by month, were the starting point for the data utilized in the models.

First, customer classes were analyzed to determine whether natural gas usage was associated with heating purposes and therefore correlated with weather with input from Montana-Dakota's Gas Supply Department. The general idea of heat-sensitivity is that some customers will increase the amount of natural gas that they consume as the outside temperature drops. Typically, this increase in consumption is cyclical with the calendar – as fall and winter set in, natural gas volumes sold to customers tend to increase. However, there are certain customers and instances in which colder weather is not correlated with the amount of natural gas consumed – these customers are considered non-heat-sensitive.

All firm service customer classes were determined to be heat-sensitive. Interruptible and transportation customers were analyzed on an individual basis and grouped into heat-sensitive and non-heat-sensitive by each customer class.

Q. How were the normalized volumes calculated for heat-sensitive customers?

A. For customer classes and individual customers that were determined to be heat-sensitive, weather and billing data were incorporated into a regression model for each respective class of service. To incorporate seasonal weather patterns, billing period degree days based on a 60-degree day were included as an input in the modeled regressions. Billing data used as inputs in the model were the monthly distinct count of customers and the actual dekatherms of gas consumed. The time period for each customer class in the modeled regressions was 36 months, or 3 years.

Using the results of the regression analysis for residential and firm general service customer classes, the daily baseload use per customer was multiplied by the respective number of days in each calendar month to arrive at the monthly baseload use per customer. The use per degree day per customer was then applied to the normal billing period degree days (based on normal weather for 30 years) to determine the normalized heating use per customer. Montana-Dakota has historically used 30-year normals for weather normalization purposes and believes that using 30-years of normal weather data continues to be most appropriate to capture historical weather trends. The results of each of these equations was then combined by the number of customers in each respective month to determine the normalized usage for the twelve months ended December 31, 2022.

Q. How were the normalized volumes calculated for non-heat-sensitive customers?

A. For customers that were determined to be non-heat-sensitive, simple averages of historical consumption patterns were utilized. These averages are considered to be the normalized volumes for the non-heat-sensitive customers. These averages were calculated at an individual customer level. For most non-heat customers, a 36 month average was calculated (January 2020 – December 2022). Exceptions to the 36 month average are discussed in more detail below.

Q. Was any consideration given to customers which changed rate classes?

A. Yes. Montana-Dakota analyzed the historical data for interruptible and transportation customers that changed rate classes during the time period in the data. During the time period of 2020 through 2022, there were no customers identified to be changing from one rate class to another. Montana-Dakota also discussed internally with its field operations and gas supply departments to determine if there were any foreseeable changes to the classifications of its interruptible and transportation customers. There were no known customers changing classes at the time of the preparation and finalization of the normalized and pro forma volumes.

Q. Were other considerations necessary for customers?

A. Yes, the removal of select customers from Rate 71 and Rate 81 was also required. Due to the margin sharing adjustment for Montana-Dakota's grain dryers through the purchased gas adjustment, all grain drying customers were removed from the Company's normalized and projected volumes for Rate 71. To further ensure the integrity of the projected volumes, customers that were not active at the end of 2022 were completely removed from the entirety of the underlying data for Rate 71 and Rate 81.

Q. How were the pro forma volumes calculated for heat-sensitive customers?

A. The pro forma volumes were based upon the calculated normalized volumes for each customer class. For the residential and firm general rate classes, Montana-Dakota utilized an annualization process to obtain a pro forma level of customers and volumes. The annualization process allows for Montana-Dakota to account for customer growth within 2022 and reflect volumes had these new customers been in service for the entire calendar year of 2022. For other heat-sensitive customers and classes, the pro forma volumes were set equal to the normalized volumes as calculated and described previously.

Pro Forma volumes for Rate 60 customers were also increased for the expected addition of customers in the North Deadwood Expansion area, as noted on Exhibit No. ___ (NAB-1).

Q. How were the pro forma volumes calculated for non-heat sensitive customers?

A. A majority of the pro forma volumes for these customers were set equal to their normalized volumes. Based on internal conversations with the Company's energy supply group and field operations staff, a different total was used. These customers will be summarized below:

In Rate 71, one customer began taking service in August of 2022. Pro forma volumes for this customer were adjusted to reflect the annual expected use. Also in Rate 71, another customer experienced reduced volumes in 2022 compared to prior years and it was determined the 2022 actual volumes were more representative of what is expected in the future.

In Rate 81, two customers experienced increasing volumes in 2022 when compared to prior years. It was determined the 2022 actual volumes were more representative of what is expected in the future.

In Rate 82, there was one customer that experienced reduced volumes in 2022 compared to prior years. In this case, it was expected that the customer would experience more use in 2023 when compared to 2022, but would not be to the level of use in prior years. Field operations staff were able to provide an estimate of total annual use expected for 2023 after discussions with the customer.

Q. Would you describe the weather data utilized in developing weather normalized gas sales?

A. Montana-Dakota purchases raw daily weather data from DTN. The data utilized in the weather normalizations is the average temperature in degrees Fahrenheit for areas that Montana-Dakota provides natural gas service in South Dakota. The daily average temperature is compared to an industry standard 60 (sixty) degrees Fahrenheit and if the temperature is below 60 degrees, the difference is considered the degree day value. For example, if the average daily temperature is 55 for March 1st, then the amount of degree days is 5 (60-55=5). These temperatures are collected from three regional weather stations in South Dakota (Mobridge, Pierre, and Rapid City) and the differences for each day are considered calendar degree days. These calendar degree days for each respective area are then weighted based upon the amount of historical number of bills that are sent to customers in each respective billing period cycle to calculate a billing period degree day (BPDD) for each of the three regions. These regional BPDDs are then weighted based upon the historical number of firm customer service points to calculate a system-wide South Dakota BPDD.

Q. Would you describe the methodology used to calculate customer counts?

A. Montana-Dakota's Customer Care and Billing System (CC&B) was the starting point for the development of the customer counts. Microsoft Excel's Distinct Count function was used to count the number of unique customers. The Count function in Excel counts the total number of values corresponding to a range of data, regardless if a specific value has multiple entries in the data set. The Distinct Count function has been utilized by Montana-Dakota to determine its customer counts in rate cases filed in other jurisdictions as it accounts for adjustments and corrections to customer bills in the CC&B data set.

Q. Does this complete your direct testimony?

A. Yes, it does.

Montana-Dakota Utilities Co.
Gas Utility - South Dakota
Normalization Summary
For the Twelve Months Ending December 31, 2022

	Customers				Volumes			
	Per Books Customers	Normalized	Annualized		Per Books Volumes	Normalized	Annualized	
Rate 60 - Residential	56,822	56,822	57,300	1/	4,083,240.9	3,767,299	3,803,810	1/
Rate 70 - Small Firm General	5,427	5,427	5,457		798,830.7	705,619	710,454	
Rate 70 - Large Firm Sales:								
Rate 70 - Large Firm General	2,072	2,072	2,089		2,613,978.9	2,462,365	2,486,065	
Rate 70 - First Through Meter	9	9	9		12,617.9	12,618	12,618	
Rate 70 - Large:	2,081	2,081	2,098		2,626,596.8	2,474,983	2,498,683	
Rate 72 - Optional Seasonal	1	1	1		71.3	105	105	
Total Large Firm Sales:	2,082	2,082	2,099		2,626,668.1	2,475,088	2,498,788	
Rate 71 - Small IT Sales:								
Rate 71 - Non-Heat Sensitive	4	5	5		15,397.4	22,264	25,237	
Rate 71 - Contract Cust 71-6	1	1	1		2,693.7	2,698	2,698	
Rate 71 - Sm IT - Grain Drying	20	0	0		35,154.9	0	0	
Total Rate 71:	25	6	6		53,246.0	24,962	27,935	
Rate 81 - Small IT Transport:								
Rate 81 - Non-Heat Sensitive	10	10	10		201,098.3	193,165	197,622	
Rate 81 - Contract Cust 81-11	1	1	1		31,035.9	26,637	31,036	
Rate 81 - Contract Cust 81-12	1	1	1		22,242.0	26,060	26,060	
Rate 81 - Heat Sensitive	8	8	8		85,088.1	77,709	77,709	
Total Rate 81:	20	20	20		339,464.3	323,571	332,427	
Rate 82 - Large IT Transport:								
Rate 82 - Non-Heat Sensitive	8	8	8		883,577.8	923,971	921,571	
Rate 82 - Heat Sensitive	2	2	2		206,537.8	195,136	195,136	
Total Rate 82:	10	10	10		1,090,115.6	1,119,107	1,116,707	
Rate 85 - Large IT Sales:								
Rate 85 - Heat Sensitive	2	2	2		403,005.2	381,433	381,433	
Total:	**64,388**	**64,369**	**64,894**		**9,394,570.8**	**8,797,079**	**8,871,554**	

1/ Annualized customers includes the addition of 63 apartment customers for 2023 Deadwood expansion. Annualized volumes include the addition of 3,150 dk for additional Deadwood Expansion customers. The additional customers volumes were calculated using an estimated 50 Dk annual use.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-___

Direct Testimony

Of

Tara R. Vesey

Q. Would you please state your name and business address?

A. My name is Tara R. Vesey, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Would you please describe your duties as Regulatory Affairs Manager?

A. I am responsible for the preparation of cost of service studies, fuel cost adjustments, purchased gas cost adjustments, and electric and gas tracking adjustments in each of the jurisdictions in which Montana-Dakota operates.

Q. Would you please describe your education and professional background?

A. I graduated from North Dakota State University with a Bachelor of Science degree in Economics. I started my career with Montana-Dakota in 2019 as a Regulatory Affairs Manager. Prior to that I was employed for 13 years by a power cooperative. During that time, I held positions of increasing responsibility, including Contract Administrator, Sales Manager, Transportation Manager, and Manager of Market Operations and Logistics.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana, North Dakota and Wyoming, and the Public Utilities Commission of Minnesota.

Q. Are you familiar with the books and records of Montana-Dakota and the manner in which they are kept?

A. Yes. Montana-Dakota's books and records are kept in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the South Dakota gas operations per books cost of service for the twelve months ended December 31, 2022, and the pro forma cost of service reflecting known and measurable adjustments that will occur by December 2023. Based on the results, I have prepared the calculation of the revenue deficiency.

I will also discuss the Company's proposal to include the pension and benefits regulatory asset, post retirement regulatory asset, and cash working capital adjustment in rate base. Furthermore, I will present proposed changes to Rate 88 – Purchased Gas Cost Adjustment to be established in conjunction with this filing.

Q. What statements, schedules and exhibits are you sponsoring?

A. I am sponsoring Statements D through F, Statement H, Statement I, pages 1 through 6, Statement J through M, Statements P through R, Exhibit No.___(TRV-1), Exhibit No.___(TRV-2), and the proposed Rate 88 – Purchased Gas Cost Adjustment presented in Appendix B of the Application.

Q. Were these statements and exhibits prepared by you or under your direct supervision.

A. Yes, they were.

<u>Case Description</u>

Q. What is included in this Revenue Requirement?

A. The Company is requesting $7,418,636, which represents an 11.2 percent increase, based on a pro forma 2023.

Q. How was the $7,418,636 revenue requirement derived?

The Company has developed the pro forma revenue requirement based on adjustments to the sales revenues, Operation & Maintenance (O&M) expenses, taxes and the December 31, 2023 pro forma rate base. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

Pro Forma Revenue Requirement

Q. What were the results of South Dakota's gas operations for the twelve months ended December 31, 2022?

A. Rule 20:10:13:96, Statement M, pages 1 and 2 show the per books income statement and rate base for total Company and South Dakota. As shown on page 1, South Dakota gas operations had a return on rate base of 3.858 percent for the twelve months ended December 31, 2022. The details for each line item, i.e. sales revenue, transportation revenue, other revenue, etc., are included in the applicable Rule listed. Pages 3 and 4 list the pro forma adjustments to operating revenues, expenses and rate base. All adjustments were calculated on either a South Dakota specific basis or on a total Company basis and allocated to South Dakota, as indicated on the statement or schedule detailing each adjustment.

Q. How was the per books cost of service allocated to South Dakota?

A. The Company utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense and rate base to the jurisdictions as part of the regular accounting process on a monthly basis. The allocation methods and procedures are the same as have previously been used in Commission proceedings and are based on the principle of assigning and/or allocating costs to the cost causer.

Q. What test period are you using to determine the revenue requirement?

A. The revenue requirement is based on a pro forma year ending

December 31, 2023 test period. As stated by Ms. Kivisto, the revenue increase is largely driven by:

	Amount (in millions)
O&M Increase	$4.7
Rate Base	1.0
SSIP	0.4
Depreciation Increase	1.5
Income Tax Reduction	(0.3)
Other	0.1
	$7.4

Montana-Dakota's cost of doing business in South Dakota is increasing despite the Company's effort to control costs and increase efficiency. The Company is experiencing a $4.7 million increase in O&M expenses due to increased costs associated with labor, subcontract labor, vehicles and work equipment, and software maintenance. Other plant additions, including System Safety Integrity Program (SSIP), represents another $1.4 million increase. Finally, increases in depreciation expense, primarily driven by the increased investment in plant, result in a revenue requirement increase of approximately $1.5 million.

Q. What criteria were used to determine the pro forma adjustments?

A. The pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2023, conformed to past Commission practices and are listed on pages 3 and 4 of Rule 20:10:13:96, Statement M. All of these adjustments are reasonably certain to occur and can be measured with reasonable accuracy, thus meeting the criteria of known and measurable.

The details for each line item, i.e. sales revenue, other revenue, etc., are included in the applicable Statement or Rule listed. All adjustments were calculated on a South Dakota specific basis as indicated on the statement or schedule detailing each adjustment.

Q. Would you describe the pro forma adjustments to the income statement and rate base?

A. Yes. The adjustments to the income statement are summarized on Rule 20:10.13:96, Statement M, page 3 and consist of adjustments to revenue, operation and maintenance expenses, depreciation expense, taxes other, and current and deferred income taxes. The adjustments to rate base are summarized on page 4 and include plant, accumulated reserve for depreciation and associated additions and deductions. Each adjustment is discussed in detail below.

<u>Pro Forma Income Statement</u>

Q. What adjustments were made to operating revenues?

A. The adjustments to operating revenues are contained in Rule 20:10:13:85, Statement I.

Adjustment No. 1 restates the per books volumes at current rates, adjusted to reflect an annual gas cost for 2023, exclusive of the surcharge adjustment, and eliminates the unbilled revenue and margin sharing credit, decreasing revenue by $6,900,925.

Adjustment No. 2 decreases revenues by $3,899,674 to reflect the effect of normal and annualized weather on sales and transportation volumes, as weather was 8.6 percent colder than normal in 2022. The normalization process and results are fully supported by Mr. Bensen's testimony.

Adjustment No. 3, located on page 5 of Statement I, is comprised of several adjustments to miscellaneous operating revenues. The pro forma adjustment decreases revenue by $241,038 and consists of several adjustments. The specific details of each adjustment are shown on Workpaper Statement I, page 1. They are as follows:

- Reconnect Fee, Reconnect Fee for Non-payment, NSF Check Fees, Sale of Junk Material, Patronage Dividends, Meter Reading for Others, and Miscellaneous Revenue were adjusted to reflect a three-year average;
- Energy Diversion was adjusted to reflect a three-year average resulting in a small reduction;
- Rent from Property was updated to reflect actual 2023 activity on an annualized basis;
- Late payment revenue is based on a three-year average ratio of the late payment revenue collected and the sales and transportation revenue, which is then applied to the Pro Forma Revenue;
- Conservation and Tracking Adjustment Revenue totaling $117,888 was removed to reflect the revenue recovery through the Conservation Program Tracking Mechanism Rate 90; and
- Penalty revenue was adjusted to reflect a two-year average.

Q. What adjustments were made to operations and maintenance (O&M) expenses?

A. The adjustments to operation and maintenance expenses are summarized in Rule 20:10:13:80, Statement H, pages 1 through 3 and are contained in Rule 20:10:13:81, Schedule H-1.

The adjustment to the cost of gas (Adjustment No. 4) is shown on Rule 20:10:13:81, Statement H, Schedule H-1, page 3, and adjusts the cost of gas to reflect the pro forma dk sales volumes, which were discussed earlier and were the basis for revenue, and an annual 2023 gas cost level. The pro forma cost of gas per dk was derived by calculating the annual demand charges based on the March 2023 purchased gas cost adjustment and the 2023 projected commodity cost of gas.

Q. Would you describe the development of labor and benefits expense?

A. Yes. Labor expense is shown as Adjustment No. 5, in Rule 20:10:13:81, Statement H, Schedule H-1, page 4, with actual labor expense for the twelve months ended December 31, 2022 used as the starting point.

The pro forma labor was developed by removing the labor costs associated with the South Dakota Rate 90 Conservation Program Tracking Mechanism and then applying a 3.96 percent increase. The 3.96 percent increase is based on the weighted average increases of 3.0 percent for union employees and 4.5 percent for non-union employees as shown on Statement H, Schedule H-1, page 6. In addition, incentive compensation has been adjusted to reflect an average target level of 12.21% of straight time and vacation. Labor expenses associated are further defined in page 5 of Statement H, Schedule H-1.

Adjustment No. 6 is an overall increase of $176,252 in benefits expense as shown on page 7 of Statement H, Schedule H-1 with additional support provided on page 8. The 2023 pro forma benefits expense reflects the removal of benefits associated with the South Dakota Rate 90 Conservation Program Tracking Mechanism. Benefits expense consists of medical/dental insurance, pension expense, post-retirement, 401K, workers compensation, and other benefits. Each of these items was adjusted individually using current information and applying the percentage increase to each type of benefit.

Medical and dental expense is increasing 13 percent per year based on the premiums in effect for 2023. Pension expense is increasing 125.66 percent reflecting an increase in the interest expense and lower than expected asset returns. The Company has made significant contributions to the pension fund to minimize expense and maintain adequate pension funding. Post-retirement expense is decreasing by 16.91 percent from 2022 levels. Pro forma 401(k) expense, workers compensation and other benefits are increasing consistent with the change in labor costs. Page 8 represents additional benefit information.

Q. Would you describe the other adjustments made to O&M expense?

A. Yes. Adjustment No. 7, shown on page 9, Statement H, Schedule

H-1 for vehicles and work equipment is an increase of $752,155 and reflects all expenses associated with the Company's vehicles and equipment, such as backhoes, skid steers, and excavators, including the costs of fuel, insurance, maintenance and depreciation expense. Adjustment No. 7 reflects an increase in this accountdue to the change in depreciation rates, specifically the Power Operated Equipment. It is calculated based on the pro forma plant and the depreciation rates in Statement J. The depreciation expense associated with these items is not charged to depreciation expense but rather is charged to a clearing account where it is then recorded in O&M expense as the vehicles or work equipment is used. The Pro Forma Adjustment is based on pro forma plant and projected depreciation rates. Absent the proposed depreciation study, the adjustment would have been an increase of approximately $7,400.

Adjustment No. 8, for Subcontract Labor expense shown on Statement H, Schedule H-1, page 10 is based on the Pro Forma adjusted value, to reflect the increase of $212,361. This increase is primarily due to the increased need for subcontract labor associated with line locating and leak surveying.

Adjustment No. 9, for materials expense, shown on Statement H, Schedule H-1, page 11 reflects an increase of $41,345. This 9.4% increase is based on information provided by the Company's major material supplier and was added to the pro forma period.

Adjustment No. 10 for Software Maintenance expense, shown on Statement H, Schedule H-1, page 12, is an increase of $50,196 and is based on pro forma estimated levels. The costs associated with the Pro Forma timeframe are based on the three-year average increase of expense and reflect expenses related to a variety of software packages and subscription renewals serving various departments, including mandated security needs.

Company consumption (Adjustment No. 11) shown on page 13 of Statement H, Schedule H-1, is the expense for general utilities, electric and natural gas consumption in Company buildings and is expected to decrease. The electric component is projected to remain unchanged while the natural gas component is expected to decrease $9,317 due to an 11.71% decrease in normalized firm sales revenues associated with the pro forma cost of gas.

Adjustment No. 12 for uncollectible accounts expense, shown on page 14 of Statement H, Schedule H-1, is a decrease of $40,503 based on five year average ratio of net write-offs to revenues applied to pro forma sales and transportation revenues.

Postage expense, shown on page 15 of Statement H, Schedule H-1 (Adjustment No. 16), is an increase of $24,368 and reflects a 13.18% increase in postage costs based on the pro forma weighted average increase that is then partially offset by electronic billing savings for the year.

Adjustment No, 14 for advertising expense, is shown on page 16 of Statement H, Schedule H-1 and reflects a decrease of $38,916. Pursuant to past Commission policy, general promotional advertising expenses have been eliminated. Informational and institutional advertising is adjusted to exclude advertising that is not applicable to South Dakota gas operations.

Q. Would you explain why you are including institutional advertising expenses?

A. Montana-Dakota is seeking to include institutional advertising that benefits customers and serves the public interest. As a corporate citizen, Montana-Dakota needs to be active in the communities that it serves. Montana-Dakota's motto is "In the community to serve" and one of the ways to demonstrate being a strong community member is to advertise the Company and what it does for the communities. Communities expect nothing less and advertising in the local newspapers, on television, in school yearbooks, programs, etc., is a necessary part of being active in the community. This advertising benefits the community and the customers in that community, thus serving the public interest.

Q. Would you please continue with your explanation of adjustments to operation and maintenance expenses?

Adjustment No. 15 for Insurance expense, shown on page 17 of Statement H, Schedule H-1, reflects an increase of $69,720. This increase is adjusted to reflect anticipated 2023 expenses and a 5 year average of self-insurance expense.

Industry dues, shown on pages 18 and 19 (Adjustment No. 16) reflects the pro forma level of industry dues and is a decrease of $146. These pages show those dues that are directly assigned or allocated to South Dakota, the appropriate pro forma expense level, and the benefit to the ratepayer.

Adjustment No. 17 for Regulatory Commission Expense as shown on page 20 of Statement H, Schedule H-1, reflects the expenses to be incurred in this filing and the expenses related to depreciation studies, amortized over a five-year period, and a three year average of ongoing regulatory commission expenses. The adjustment is an increase of $125,132. Because the expense incurred for this filing is proposed to be amortized over a five-year period, the unamortized balance has been included in rate base as a Working Capital addition.

Adjustment No. 18 for office supplies expense, shown on page 21 of Statement H, Schedule H-1, reflects an increase of $2,146. This includes a normalizing adjustment to reflect the average costs from 2018 to 2022. The average costs were considered in an effort to smooth out the temporary reduction in office supplies associated with the COVID-19 pandemic.

Annual easements are shown on page 22 of Statement H, Schedule H-1 as Adjustment No. 19. This adjustment reflects an increase of $5,036.

The items adjusted individually above represent approximately 96 percent of total South Dakota gas O&M. The remaining items, which make up approximately 4 percent of other O&M, were adjusted to exclude the costs associated with Conservation Program Tracking Mechanism.

Q. Would you describe the calculation of depreciation expense?

A. The adjustment to depreciation expense is contained in Rule 20:10:13:86, Statement J. Adjustment No. 21 restates the annual depreciation expense to the average pro forma level of plant in service. Concentric Advisors, ULC prepared gas and common plant depreciation studies, at the Company's request, for gas and common assets based on the plant balances on December 31, 2021. The depreciation studies are supported in the testimony of Mr. Kennedy. The depreciation rates are shown on Statement J, pages 2 through 4.

The total pro forma change to depreciation expense is a decrease of $23,249, as shown on Rule 20:10:13:86, Statement J, page 1. Absent the proposed depreciation studies, the adjustment would have been an increase of approximately $599,000.

Q. What adjustments were made to taxes other than income?

A. The adjustments to taxes other than income are contained in Rule 20:10:13:94, Statement L and Rule 20:10:13:95 Statement L, Schedule L-1.

Adjustment No. 22 restates ad valorem taxes to the pro forma level of plant in service based on the 2022 ratio of ad valorem taxes to plant. The net result is an increase of $49,674.

The adjustment to payroll taxes (Adjustment No. 23) is an increase of $44,654 based on the ratio of payroll taxes to labor expense for 2022 applied to pro forma labor expense, excluding the $616 related to the South Dakota Conservation Program Tracking Mechanism.

Adjustment No. 24 for the South Dakota Gross Receipt Taxes is based on the Company's revenue and the current Gross Receipts Tax rate of 0.15 percent. This results in an increase of $21,151.

Q. What adjustments were made to income taxes?

A. The adjustments to income taxes are summarized in Rule 20:10:13:88, Statement K, page 1.

Adjustment No. 25 is for interest expense and is based on the pro forma rate base and cost of debt. It is shown on Rule 20:10:13:88, Statement K, page 9. Interest is deductible for tax purposes and interest expense is calculated on the pro forma rate base using the weighted cost of debt from Rule 20:10:13:72, Statement G, page 1. The resulting interest expense is an increase of $294,669.

Adjustment No. 26, shown on page 10 reflects the net tax depreciation and deferred taxes on the pro forma plant additions. The calculation of net tax depreciation and the resulting deferred taxes on the plant additions are shown on page 18 of Rule 20:10:13:72, Statement G.

Adjustment No. 27, the pro forma adjustment to current income tax on operating revenues and expenses are calculated on page 11.

Shown on page 12 of Rule 20:10:13:72, Statement G, Adjustment No. 28 reflects an adjustment to the per books 2022 actual results to reflect the impact of the federal tax rate on current and deferred income taxes.

Adjustment No. 29, on page 13, is the change in plant related excess deferred income taxes.

Pro Forma Rate Base

Q. How would you describe the development of the rate base?

A. The pro forma rate base is based on the 2022 rate base and reflects known and measurable adjustments that will occur within twelve months ending December 31, 2023. The pro forma adjustments to rate base are summarized on Rule 20:10:13:96, Statement M, page 4.

Adjustment A is the known and measurable plant additions that will be in service by December 31, 2023. The increase includes additions to distribution, general and common plant and the additions are shown on Rule 20:10:13:54, Statement D, pages 2 through 4. Rule 20:10:13:56, Statement D, Schedule D-2, pages 3 and 4 contain the detailed plant additions of $10,302,867.

Adjustment B, shown in Rule 20:10:13:64, Statement E page 1, decreases the reserve for depreciation on the per books plant by $11,623. The provision for depreciation included in this adjustment is inclusive of half of the change in pro forma depreciation expense. This is consistent with the Settlement Stipulation in Docket No. NG15-005.

Q. How were the working capital items derived?

A. The working capital adjustments are summarized in Rule 20:10:13:68, Statement F, page 1.

Detailed information for Adjustments C through K is shown on Rule 20:10:13:69, Statement F, Schedule F-1, pages 1 through 9. Materials and supplies, prepaid insurance, and customer advances for construction are restated to a thirteen-month average balance on pages 1, 2, and 9 reflecting actual balances through February 28, 2023 in Adjustments C, D, and K. Materials and supplies project March 2023 through December 2023 based on prior period actual results. Prepaid Insurance and Customer Advances on Construction project March 2023 through December 2023 is based on expected expenses. Adjustments to materials and supplies, prepaid insurance, and customer advances for construction result in an increase of $47,973, $135,521, and $85,521, respectively.

Adjustments E, F, and G represent the adjustments to the unamortized loss on reacquired debt balances, unamortized redemption of preferred stock, and unamortized rate case expense, and the associated deferred income taxes to reflect 2023 activity. This activity is shown on pages 3 through 5.

The Company is proposing to include the provision for pensions and benefits, the provision for post retirement, and the cash working capital adjustment in the revenue requirement for the 2023. The associated accumulated deferred income taxes for pensions and benefits and post retirement were also included. All three items are discussed in detail below.

Q. Montana-Dakota has proposed to include the net pension regulatory asset in rate base. Will you explain why?

A. Yes. As discussed in the testimony of Ms. Kivisto, the Company's required contributions to the pension account resulted in a significant prepaid asset and exceeded the amount of pension expense (commonly referred to as FAS 87 or ASC 715 expense) recovered through the revenue requirement. The contributions are tax deductible for Montana-Dakota and any earnings on those contributions in the pension trust account are not subject to income tax. With that in mind, the contributions help maintain the required funding level and, at the same time, typically result in lower FAS 87 expense.

Post retirement contributions are typically much more closely matched to the annual expense, so the prepaid asset is much smaller. However, Montana-Dakota considers the benefits and the circumstances surrounding the creation of both prepaid assets or liabilities that it is appropriate to include both pension and post retirement similarly.

The table below presents the pension and benefits regulatory asset or liability position for Montana-Dakota's for MDU beginning in December 2004 through December 2022. As shown, Montana-Dakota has made cash contributions in the amount of $81.5 million but has recovered only $27.8 million through the inclusion of pension expense in the revenue requirement. South Dakota gas operations' share of the total pension regulatory asset is $8.3 million as of December 31, 2022.

	Cash Contributions	Pension Expense	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj.	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Activity - 2020		(177,300)	59,934,780
Activity - 2021		(727,718)	60,662,498
Activity - 2022		(814,687)	61,477,185
Total Funding	$81,544,704	$27,844,785	
Ending Balance - 12/31/2022			$ 61,477,185

Q. Is Montana-Dakota required to make contributions to its pension trust fund? And what are the ramifications if funding is not maintained?

A. Yes. Internal Revenue Service rules govern minimum required pension funding contributions. If required contributions are missed or delayed, the missed payment would be considered a reportable event under the Employee Retirement Income Security Act of 1974 (ERISA) rules. This could also subject the Company to excise taxes for failure to meet minimum funding requirements. In addition, if the funded status drops below certain levels, restrictions on benefit payments may be required as well as potentially increased premiums payable to the Pension Benefit Guaranty Corporation.

Q. Montana-Dakota has included pension and post-retirement benefits in this filing. Will you explain why the Company has decided to include these regulatory assets in rate base at this time?

A. As reflected in the table above, the pension regulatory asset fluctuates from an asset to a liability and then, beginning in 2012, started to increase to a magnitude as the Company had made significant funding contributions. However, the amount recovered through the revenue requirement (i.e. recovery of FAS 87 expense as a component of operating expenses) has decreased to the point that the regulatory asset has become a material asset upon which Montana-Dakota is not able to earn a return.

The Company was evaluating the inclusion of pension and post retirement at the time of the last gas rate case (Docket No. NG15-005) but did not include the regulatory assets at that time. Since that time, Montana-Dakota has been proposing the inclusion of pension and benefits and post-retirement benefits regulatory assets in other jurisdictions.

Montana-Dakota's proposals have been accepted by the Public Service Commissions of North Dakota, Montana, and Wyoming.

Post retirement benefits regulatory assets are similar in nature, as mentioned earlier, but is on a smaller scale.

Q. Please describe Exhibit No.__(TRV-2).

A. Exhibit No.__(TRV-2) was prepared to present the Company's historic view of the pension regulatory asset and liability balances.

Q. Has the Company added any other new adjustments to be considered?

A. Rule 20:10:13:68, Statement F, page 8 Adjustment J is the cash working capital adjustment. In Docket No. NG15-005, South Dakota Public Utilities Commission staff computed a cash working capital adjustment which was included in the computation for the Settlement Stipulation. In an effort to remain consistent with the last case, Montana-Dakota contracted with Concentric Energy Advisors, Inc to perform a lead/lag study in order to create a cash working capital adjustment. The lead/lag study is fully supported in the testimony of Mr. Adams. The calculation of the cash working capital adjustment was performed by applying the expense lead and revenue lag days from the lead-lag study to the applicable pro forma level of revenue or expense. This resulted in a decrease in the rate base of $295,430 and a reduction in the revenue requirement of approximately $36,000.

Q. Would you describe how the accumulated deferred income tax balance was developed?

A. The adjustments to accumulated deferred income taxes are summarized on Rule 20:10:13:88, Statement K, page 1.

Adjustment L on page 17 of Statement K reflects the pro forma balances that were derived by adding the changes to the deferred income taxes to the Pro Forma Adjusted balances and calculating the average balance.

Q. Are you proposing any changes to Rate 88 – Purchased Gas Cost Adjustment?

A. Montana-Dakota has proposed a Firm General Contracted Demand Service Rate 74 as discussed by Ms. Bosch. Rate 88 has been updated to reflect the cost of gas to be charged for Rate 74. The Capacity Charge will be developed on an incremental pipeline capacity basis and applied to the contracted billing demand. The Cost of Gas - Commodity Charge will be based on costs applicable to firm customers, exclusive of pipeline demand charges, and will be applied to the customer's actual measured Dk for the given month.

Also, in an effort to correct a clerical error, certain spaces were eliminated and Section 5(a)(1) was updated to reflect the correct minimum filing threshold limitation referenced in Section 2(b).

Q. What is the additional revenue requirement calculated on Exhibit No.____(TRJ-1)?

A. Exhibit No.____(TRV-1), which is identical to Rule 20:10:13:96, Statement M, page 7, shows the calculation of the revenue deficiency of $7,418,636 based on the pro forma operating income and rate base and using the overall rate of return of 7.600 percent from Rule 20:10:13:72, Statement G, page 1.

Q. Does this complete your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
GAS UTILITY - SOUTH DAKOTA

	Before Additional Revenue Requirements 1/	**Additional Revenue Requirements**		Reflecting Additional Revenue Requirements
Operating Revenues				
Sales	$66,055,870	**$7,418,636**		$73,474,506
Transportation	399,242			399,242
Other	508,164			508,164
Total Revenues	66,963,276	7,418,636		74,381,912
Operating Expenses				
Operation and Maintenance				
Cost of Gas	46,787,331			46,787,331
Other O&M	14,522,624			14,522,624
Total O&M	61,309,955			61,309,955
Depreciation	5,173,363			5,173,363
Taxes Other Than Income	1,296,184	11,128	2/	1,307,312
Current Income Taxes	(170,295)	1,555,577	2/	1,385,282
Deferred Income Taxes	(654,436)			(654,436)
Total Expenses	66,954,771	1,566,705		68,521,476
Operating Income	$8,505	$5,851,931		$5,860,436
Rate Base	$77,110,997			$77,110,997
Rate of Return	**0.011%**			**7.600%**

1/ See Rule 20:10:13:96, page 5.
2/ Reflects taxes at 21 percent after deducting South Dakota Gross Receipts tax of 0.15 percent.

MONTANA-DAKOTA UTILITIES CO.
PENSION BALANCE SUMMARY
ENDING DECEMBER 31, 2022

	Cash Contributions 1/	Pension Expense 2/	Pension Balance Debit (Credit)
Beginning Balance - 12/31/2004			$7,777,266
Activity - 2005	$0	$4,179,348	3,597,918
Activity - 2006	-	4,118,976	(521,058)
Activity - 2007	1,188,690	3,724,426	(3,056,794)
Activity - 2008	-	2,825,775	(5,882,569)
Activity - 2009	8,347,434	4,759,097	(2,294,232)
Activity - 2010	3,871,657	(5,328)	1,582,753
Activity - 2011	13,757,133	1,610,332	13,729,554
Activity - 2012	12,038,687	(740,118)	26,508,359
Activity - 2013	10,014,592	1,830,351	34,692,600
Activity - 2014	12,202,457	594,340	46,300,717
Activity - 2015	2,182,143	1,398,780	47,084,080
Activity - 2016	-	1,746,833	45,337,247
Activity - 2017	422,015	1,422,159	44,337,103
Activity - 2018	7,200,692	720,403	50,817,392
Corporate Reorg. Adj. 3/	(5,133,171)	-	45,684,221
Activity - 2019	15,452,375	1,379,116	59,757,480
Activity - 2020		(177,300)	59,934,780
Activity - 2021		(727,718)	60,662,498
Activity - 2022		(814,687)	61,477,185
Total Funding	$81,544,704	$27,844,785	
Ending Balance - 12/31/2022			$ 61,477,185

1/ Actuarially determined cash payments to the pension trust fund.
2/ Actuarially determined pension expense use in the development of the revenue requirement through rate cases.
3/ Adjustment to reflect the removal of MDU Resources pension funding - cash received by Montana-Dakota due to the 1/1/2019 corporate reorganization in Docket No. GE18-001.

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23 - ___

Direct Testimony

of

Ronald J. Amen

August 15, 2023

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing; competitive market analysis; regulatory planning and policy development; resource planning and acquisition; strategic business planning; merger and acquisition analysis; organizational restructuring; new product and service development; and load research studies. I have prepared and presented expert testimony before utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A.

Q. Have you previously testified before the South Dakota Public Utilities Commission ("Commission")?

A. No.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the various rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation

- Montana-Dakota's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement N, Statement O, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate Schedule Bill Comparisons

II. THEORETICAL PRINCIPLES OF COST ALLOCTION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded COSS is a useful tool for determining the allocation of Montana-Dakota 's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecasted test year or some combination of historical and future costs. Where a forecasted test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, the costs of mains vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Montana-Dakota because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer’s load characteristics.

These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in Montana-Dakota's COSS?

A. Yes. Special studies were performed to determine a portion of the specific distribution plant installed to serve Montana-Dakota's Small Firm General, Small

Interruptible, and Large Interruptible customers. The costs related to these facilities from the following plant accounts were directly assigned to the Small Firm General, Small Interruptible, and Large Interruptible.

- Account 378 – Measuring & Regulating Equipment – General. Direct assignment to Small Firm General (Rate 70).
- Account 383 – Service Regulators. Direct assignment to Small Firm General (Rate 70), Small Interruptible (Rates 71 and 81) and Large Interruptible (Rates 82 and 85).

III. MONTANA-DAKOTA'S COST OF SERVICE STUDY

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Montana-Dakota's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include production (i.e., gas supply expenses), distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Montana-Dakota's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of South Dakota as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single-pressure based operation.

Q. What are the specific physical characteristics of Montana-Dakota's system?

A. The physical configuration of Montana-Dakota's system is a dispersed / multiple city-gate, primarily distribution-only and multi-pressure based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility’s books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available. Montana-Dakota maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are Montana-Dakota’s classes structured for purposes of the COSS?

A. The COSS evaluated five customer classes: Residential, Small Firm General, Large Firm General, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation.

Q. How do state regulatory policies bear upon a utility’s COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations may set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the cost allocation method utilized by the utility.

B. Classification and Allocation of Distribution Mains

Q. How did the Company’s COSS classify and allocate investment in Distribution Mains?

A. The Company classified 27.8% of its investment in distribution mains as customer related and 72.2% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Montana-Dakota’s system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a “design day” basis.

Q. Please explain the basis for the Company’s choice of classification and allocation methods.

A. It is widely accepted that distribution mains (FERC Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the LDC's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by an LDC in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is the method used by the Company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Montana-Dakota's COSS, both the zero-intercept method and the minimum system method were employed to test the reasonableness, by comparison, of the two approaches. The zero-intercept method produced the

27.8% customer component used in the COSS. The minimum-sized unit method resulted in a 32.3% customer component.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, <u>Electric Utility Cost Allocation Manual</u>, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and <u>Gas Rate Fundamentals</u>, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, <u>Gas Rate Design Manual</u>, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. With respect to Montana-Dakota's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. The zero-intercept method typically uses weighted linear regression analysis to compare unit costs of the various sized distribution mains installed on Montana-Dakota's gas system against the size (diameter) of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. The results of the linear regression analysis can be expressed formulaically as follows:

$$y = mx^2 + b$$

Where: y = average cost per installed foot of Montana-Dakota's distribution mains

m = cost per installed foot, per inch of pipe diameter

x^2 = diameter squared of distribution mains

b = minimum cost per installed foot (the zero-intercept)

This equation determines that regardless of the main's diameter, the average cost of a distribution main on Montana-Dakota's gas system will be at least equal to a minimum cost per installed foot. This per foot cost component is exclusively related to the simple fact that Montana-Dakota incurs this cost to install a main, regardless of its size. That is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains. This is the per foot customer cost component of Montana-Dakota's distribution mains as distinguished from the per foot demand cost component, which is equal to a cost per foot times the diameter of the distribution main.

Q. Do the results of the zero-intercept method described above therefore support the 27.8% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the regression results for plastic mains of $5.43 and steel mains of $11.19 per foot cost of the “zero inch” distribution main to the Company’s total footage of distribution mains results in an investment amount equivalent to approximately 27.8% of the total investment in distribution mains, on a current cost (year 2023) basis.

Q. How do the results under the zero-intercept method compare to the results under the most commonly installed, minimum-sized mains investment approach for Montana-Dakota’s South Dakota service territory?

A. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch plastic pipe. In the last sixty-four years,1959 through 2022, 4.2 million feet out of approximately 7.9 million total feet or 53% of distribution mains installed in Montana-Dakota’s South Dakota service territory was 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic. Since 1959, the second most footage of installed distribution mains was 4-inch plastic pipe, approximately 1.3 million feet. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 32.3%.

Q. Montana-Dakota’s distribution mains plant data for South Dakota indicates the installation of smaller sized pipe (1 ¼-inch) over the 64-year period. Why wasn’t a smaller pipe size chosen for the minimum system analysis?

A. Information provided by Montana-Dakota’s engineering and construction personnel indicated that use of the smaller sized pipe (i.e., less than 2-inch) for distribution mains is limited to special situations, such as a street crossing from a larger size main to provide service to two or three premises. These smaller size main segments are installed when a subdivision's underground utility infrastructure – water, sewer, power – roadbeds, and curbing are installed. These smaller diameter pipes are treated for plant accounting purposes as distribution mains since no service lines will be installed until a house structure is under construction and final grading of the property is complete.

Q. Would one expect there to be a strong correlation between the number of customers served by Montana-Dakota and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Montana-Dakota's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Montana-Dakota represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

C. Distribution and General Plant Classification and Allocation

Q. How were the remaining Distribution Plant costs treated in the COSS?

A. As discussed earlier, where possible, costs were directly assigned to the customer classes based on data in the Company's plant records. Weighting factors were developed for plant costs in FERC Account Nos. 380 (Services) and 381 (Meters) based on the size and type of the facilities and equipment. The classification and allocation of the remaining account balances of the directly assigned costs discussed earlier were based on the meters and distribution mains allocators, respectively. The costs in Accounts Nos. 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate), and 387 (Cathodic Protection Equipment) were classified and allocated based on the Design Day Peak allocator. The costs in Accounts Nos. 374 (Land & Right of Way), and 375 (Structures & Improvements) were classified and allocated based on the Distribution Mains and Measurement & Regulator Station Equipment allocator.

Q. How were the General and Common Plant costs classified and allocated in the COSS?

A. With one exception, General, Intangible, and Common Plant costs were classified and allocated to the customer classes based on an internal allocation factor generated from the results of the classification and allocation of distribution plant costs. Common Intangible Plant – Customer Care & Billing (CC&B) and PragmaCAD (PCAD) plant was classified as customer-related and allocated on the average number of customers.

D. Operation & Maintenance, Customer Accounts & Services, and Administrative & General Expenses

Q. How were O&M expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the Operation & Maintenance (O&M) expenses followed the treatment of the related plant accounts. For example, the treatment of Account No. 879 (Customer Installations Expense), followed the weighted meters allocator.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading) and 904 (Uncollectible Accounts). Meter reading expenses were allocated based on the total annualized number of customers weighted by meter size. Uncollectible accounts expenses were assigned to the residential and small firm general classes based on number of customers, which reflected the historical uncollectible expense experience.

Q. Please explain the treatment of Administrative and General expenses in the COSS.

A. The majority of the A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses, excluding gas supply related costs and A&G. Taxes Other than Income Taxes and their corresponding [allocation basis] includes Ad Valorem taxes [Distribution plant]; Payroll, Franchise and Other taxes [O&M excluding gas costs]; and Revenue taxes [Pro forma operating revenue].

E. Cost of Service Study Results

Q. Please explain the COSS information contained in Statement N.

A. Statement N, Schedule N-1, pages 1 – 5, provides a report titled Cost of Service by Component. This report shows the total dollars and unit cost required under each rate if the Pro Forma rate of return of 7.600 percent were to be earned for the demand, energy, and customer cost components of each rate schedule along with a summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation. The pro forma system rate of return of 0.01%, before allocation of the requested increase, is also shown on Schedule N-1. An example of the cost of service information provided on Schedule N-1, the resulting rate of return on rate base allocated to the residential class, served under Residential Service Rate 60, is (1.87%). A revenue increase of $6,403,545 would be required to bring the residential rate of return to the overall system average requested rate of return of 7.600 percent.

A summary of the results by the major rate classifications, Residential, Small Firm General Service, Large Firm General Service, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation is provided in Statement N, Schedule N-1, pages 6 – 7.

Statement N, Schedule N-2, pages 1 – 55, titled Embedded Class Cost of Service Study, provides the complete rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in the Allocation Factor Report, Statement N, Schedule N-3, pages 1-9.

The COSS is based on the South Dakota results of gas operations recorded for the 12 months ended December 31, 2022, as adjusted to reflect pro forma adjustments sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement N, Schedule N-1, the overall rate of return for South Dakota natural gas service is 0.01% at present rates, based on the results of gas operations for the 12 months ended December 31, 2022, adjusted for known and measurable changes. The returns by customer class at current rates are shown below:

• Residential Service	(1.87%)
• Small Firm General Service	(1.01%)
• Large Firm General Service	7.15%
• Small Interruptible Sales & Transportation	10.84%
• Large Interruptible Sales & Transportation	1.58%

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you rely upon as the basis for rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

- Efficiency;
- Cost of Service;

- Value of Service;
- Stability;
- Non-Discrimination;
- Administrative Simplicity; and
- Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Montana-Dakota.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Montana-Dakota because of the competitive supply alternatives that cap rates under its flex rates.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity.

The principle of horizontal equity requires that “equals should be treated equally” and vertical equity requires that “unequals should be treated unequally.” Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different. In this case, this principle is an important requirement that supports Montana-Dakota’s proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Montana-Dakota, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permits proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

- System cost characteristics such as established in the COSS required by the Commission, or embedded customer, demand, and commodity related costs by type of service;
- Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
- Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
- Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $7,418,636 to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Montana-Dakota's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 (Unity), as shown in Exhibit No.___(RJA-1), Proposed Revenue Allocation, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario A, Equal Percentage Increase (System Average)*, in Exhibit No.___ (RJA-1). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Montana-Dakota's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Montana-Dakota's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes.

Residential Service (Rate Schedule 60), Small and Large Firm General Service (Rate Schedules 70 and 72), Small Interruptible Sales & Transportation Service class (Rate Schedules 71 and 81) and Large Interruptible Sales & Transportation Service (Rate Schedule 82 and 85), as shown in Exhibit No.___(RJA-1), Proposed Revenue Allocation, as *Scenario B: Narrow the Disparity of Revenue to cost ratios between the classes*. In the case of the Residential Service and Small Firm General Service classes, the revenue adjustments ensure their proposed rates will move class revenues very near to the COSS for the two classes. The proposed revenue increase to the Residential Service class will improve its revenue to cost ("R:C") ratio from 0.67 to 0.98. Similarly, the Small Firm General Service class will move from a R:C ratio of 0.68 to 0.98 as well. The proposed non-gas revenue increases to these two classes are 120% of the overall system average increase.

The Large Firm General Service class's R:C ratio under current rates is 0.98; therefore, the proposed revenue increase for this class is one-third of the system average increase, which raises the class R:C ratio to 1.10. The proposed 100% of the system average revenue increase for the Large Interruptible Sales & Transportation class will raise its R:C ratio from 0.73 to 1.01 of unity (1.00).

The COSS results for the remaining customer class, Small Interruptible Sales & Transportation Service, indicates a rate of return above the system average rate of return at both the Company's current and proposed ROR levels and was above unity under current rates. This would suggest the need for a modest revenue decrease of $18,520 in order to move this customer class to cost (*i.e.*, convergence of the resulting R:C ratio to Unity), as shown in Exhibit No.___(RJA-1) under *Revenues at Equalized Rates of Return*. However, the customer impact implications for the Residential Service and Small Firm General Service classes from the proposed revenue increases to these two classes has led me to conclude, in consultation with the Company, to refrain from a revenue reduction for the Small Interruptible Sales & Transportation Service class, or alternatively, exempting this class from a revenue increase. Instead, the proposed revenue adjustment of 9% of the system average increase will raise the class's current parity ratio from 1.12 relative to unity, to 1.15.

In summary, the Company's preferred revenue allocation approach resulted in meaningful movement of the Residential and Small Firm General classes revenue-to-cost ratios to within the range of reasonableness to unity or 1.00, while requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of revenue to cost responsibility movement, and reduction in the existing interclass rate subsidies, is desirable.

Q. Please discuss the information provided in Statement O.

A. Statement O, page 1 of 1, titled Revenues Under Current and Proposed Rates, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues under the present and proposed rates for each customer tariff rate schedule. The allocation of the total revenue increase of $7,420,480 to the respective rate schedules is presented in Statement O, page 1 of 1. The resulting revenue increase by rate schedule and corresponding percentage are also shown.

The allocation of the total target revenue increase to the respective rate schedules is presented on page 2 of Statement O, Schedule O-1, titled Allocation of Revenues. The pro forma 2023 billing determinants and the embedded cost of service by rate class prior to the proposed revenue increase are presented on page 1 of 8 of the Schedule. The target revenue increase as a percentage of total class revenues, including gas costs, range from 15.89% to Residential; 12.55% to Small Firm General; 2.56% to Large Firm General; 1.90% to Small Interruptible; and 6.08% to Large Interruptible, as shown on Schedule O-1, page 2 of 8. The remaining six pages of Schedule O-1, titled Rate Reconciliation, provide the derivation of the proposed rates for each Rate Schedule.

VI. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. Montana-Dakota has proposed to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules: Residential Service (Rate Schedule 60), Firm General Service (Rate Schedules 70 and 72); Small Interruptible Sales & Transportation Service (Rate Schedules 71 and 81), and Large Interruptible Sales & Transportation Service (Rate Schedules 85 and 82), as shown on Statement O, Schedule O-1 . Following the revenue increases recovered through the Basic Service Charges, except for the Small Interruptible Sales & Transportation Service rate schedules, the remaining allocated revenue increases for the remaining rate schedules will be recovered in their respective volumetric Distribution Delivery Charge components. The Small Interruptible Sales & Transportation Service rate schedules will receive a decrease in their Distribution Delivery Charges, as further described below.

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff rate schedules.

A. As seen on page 3 of Statement O, Schedule O-1, the Basic Service Charge under Residential Rate 60 is proposed at $0.55 per day which reflects an average monthly charge of $16.73, an increase of approximately $7.60 per month from the currently effective charge.

The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour is proposed at $0.82 per day, and $1.86 per day for customers requiring the larger meters capable of measuring gas flows of 500 cubic feet per hour or greater. The resulting average monthly charges will be $24.94 and $56.58 respectively, representing an increase of $8.21 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $5.48 per month in the Basic Service Charge for customers requiring meters rated at 500 cubic feet per hour or higher. The rate calculations for the Firm General Service Rate Schedules 70 and 72 are included on page 4 of Schedule O-1.

The proposed Basic Service Charge applicable to Small Interruptible Sales (Rate Schedule 71) and Transportation (Rate Schedule 81) Service customers is $210.00 per month. This level of basic charge is near the total allocated customer related costs for the Small Interruptible Service class at $218.77; as such, it improves the level of fixed costs attributable to the class recovered through a fixed monthly charge. In addition, this level of Basic Service Charge will result in a decrease in the Distribution Delivery Charge for both Sales Rate Schedule 71 and Transportation Rate Schedule 81 customers. The rate calculations for the Small Interruptible Service Rate Schedules are included on pages 5 and 6 of Schedule O-1.

The proposed Basic Service Charge applicable to Large Interruptible Sales (Rate Schedule 85) and Transportation (Rate Schedule 82) Service customers is $370.00 per month, a $95.00 increase in the level of the current charge. As stated earlier, these proposed increases to the Basic Service Charges will provide significant improvement in the recovery of the Company's fixed costs via fixed charges. The rate calculations for the Large Interruptible Service Rate Schedules 85 and 82 are included on pages 7 and 8 of Schedule O-1.

Q. Do increases in Basic Service Charges, such as those proposed by Montana-Dakota, discourage conservation of the natural gas commodity?

A. No. For example, under the Company's proposed increase to its Residential Basic Service Charge, customers will continue to have a financial incentive to pursue energy efficiency measures. The portion of the customer's gas bill represented by the Company's Basic Service Charge is less than half of the combined total bill, including the gas commodity charge incurred by the customer. As can be calculated in the accompanying Exhibit No.___(RJA-2), page 1 of 6, Residential Gas Service Rate 60 Bill Comparison, the portion of the typical residential customer's annual bill represented by the proposed increase in the average Basic Service Charge of $7.60 per month is approximately 12% of the total bill. The effect of raising the proposed Basic Service Charge by $0.25 per day, the equivalent of $7.75 per month in January, the month in which the most gas is typically consumed by residential heating customers, is only 6% of the total January bill. This is a relatively small amount. The commodity cost of gas[1] is 65% of the customer's bill in January, which continues to provide a strong economic price signal that may influence the customer's ongoing gas consumption decisions. In my opinion, the relatively small amount of fixed costs added to the Basic Service Charge that would otherwise be recovered in the volumetric Distribution Delivery Charge will not materially affect a customer's decision to use more or less gas.

By recovering its fixed distribution costs in the Residential Basic Service Charge, the Company will be able to continue promoting energy efficiency and conservation for its customers while moderately reducing the real threat of margin losses due to declining gas sales per customer.

Q. Does a volumetrically weighted rate design provide the most appropriate prices signals to customers related to gas consumption?

A. No. A volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the gas utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the gas utility's system; and (4) needlessly inflate bills in the winter months, when customers face the greatest pressure on their household budgets from utility bills. Montana-Dakota's rate design proposal to increase the level of its Basic Service Charges moves in the right direction to minimize these undesirable effects and best aligns the price signals to customers with the underlying costs of providing gas delivery service.

---

[1] Montana-Dakota's proforma cost of gas in the COSS is $6.412 per Dk.

A Basic Service Charge that better reflects the level of customer related costs will result in a customer’s annual bill more accurately reflecting the non-gas revenue amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity in their monthly bills.

In summary, a Basic Service Charge provides increased bill stability for customers and increased revenue stability for the Company.

Q. Are there other proposed rate design changes to Montana-Dakota’s non-residential rate schedules?

A. No.

VII. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared bill comparisons for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Residential customer using 66.3 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-2), Rate Schedule Bill Comparisons. The average monthly increase for this residential customer under the Company’s proposed rate design is $8.70 or 15.90%.

Q. What are the corresponding bill comparisons for Montana-Dakota’s Small Firm General and Large Firm General Service customers?

A. The monthly and annual bill impacts for a typical Small Firm General customer using 130 Dk per year is shown on page 3 of Exhibit No.___(RJA-2), Rate 70 Bill Comparison for Firm General Gas Service. The average monthly increase for this Small Firm General customer under the Company’s proposed rate design is $12.09 or 12.56%. The monthly and annual bill impacts for a typical Large Firm

General customer using 1,188.4 Dk per year is shown on page 5 of the exhibit. The average monthly increase for this Large Firm General Service customer under the Company's proposed rate design is $20.53 or 2.57%.

Q. Does this conclude your direct testimony?

A. Yes.

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska,
Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

44

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)
In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)
Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage

d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)
Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018, 2021)
Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

McDowell Rackner & Gibson Law Firm (2015 – 2016)
Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)
Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Confidential Multi-Jurisdiction Gas Utility (2021-2022)

Retained by the multi-jurisdiction interstate transmission pipeline and local distribution utility ("client") to assist it in identifying and supporting a natural gas supply solution to satisfy additional deliverability requirements with the goals of minimizing costs, enhancing system resiliency, and introducing renewable fuels into its system. Reviewed the process and analyses that had been conducted to-date (including all underlying assumptions) and provided insight on the best path forward. The goal of the effort was to help prepare client for internal approval of the process and recommended path forward, and ultimately the development and approval of the necessary regulatory filings at the federal, state, and local levels. Atrium evaluated a broad spectrum of regulatory, economic, market-related, and logistical considerations in order to advise the client on the best path forward in utilizing LNG to meet its future deliverability requirements. Specific components of Atrium's analysis included regulatory approvability, rate design and cost recovery risk, site location (including siting LNG in multiple locations in multiple states), ownership structure, and ability to incorporate RNG and hydrogen into Utility's system to decarbonize the pipeline system.

Great Plains Natural Gas (2021-2022)

Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)
Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Philadelphia Gas Works PGW (2023)
Mr. Amen led an Atrium team engaged by PGW to review the mechanics, input data, billing controls, and weather trends surrounding PGW's Weather Normalization Adjustment ("WNA") formula to understand the factors that contributed to the abnormally high WNA charges in June 2022. Atrium's review identified structural factors inherent in PGW's WNA mechanism that may have contributed to the anomalous WNA amounts billed to customers in June 2022. Mr. Amen filed testimony with Atrium's findings and recommendation in the pending general rate case before the Pennsylvania Public Utility Commission.

Potomac Electric Power Company (PEPCO) (2022-2023)
Mr. Amen led an Atrium team engaged by PEPCO on behalf of services requested by the Public Service Commission of the District of Columbia ("DC Commission"), for comprehensive evaluation of the processes, procedures, mechanics, and internal controls surrounding PEPCO's Bill Stabilization Adjustment ("BSA"). Atrium provided independent audit services sought by the DC Commission, including a) independently evaluate the timing, impact and magnitude of the billing determinant error that was identified during Formal Case No. 1156; b) independently confirm that current BSA processes and procedures are properly and timely executed as designed; c) independently confirm that current Pepco BSA internal controls are properly and timely executed; d) independently identify any recommended process and procedural improvements, as well as any recommended changes in existing internal controls or new internal controls; and e) independently conduct a comprehensive review of Pepco's BSA deferral balances by customer class, with an overall determination of the breakdown of BSA deferral balances by key drivers for each customer class. Our audit report and recommendations were filed with the DC Commission in July 2023.

Summit Natural Gas of Maine, Inc. (2022 - 2023)
Mr. Amen provided revenue requirement, allocated cost of service, class revenue apportionment, rate design, and expert witness testimony support for the utility's gas general rate case and multi-year rate plan before the Maine Public Utilities Commission. Responsibilities included determination of an optimal normal weather period for purposes of normalizing test year billing determinants, followed by the weather normalization process of determining a representative level of gas throughput for the Company's test year. The case resulted in an all-party settlement before the Maine PUC.

Black Hills Energy Arkansas (2021-2022)

Mr. Amen provided allocated cost of service, class revenue apportionment, rate design for natural gas infrastructure mechanisms, and expert witness support for the utility's gas general rate case before the Arkansas Public Service Commission. The case resulted in a settlement before the Arkansas PSC.

Until Electric System and Northern Utilities, Inc. (2021 - 2022)

Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission, including expert witness testimony. The cases resulted in settlements before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021-2022)

Retained to provide an independent review of the cost of service methodologies employed for Centra Gas Manitoba Inc.'s natural gas operations. Atrium prepared a report filed with the Manitoba Public Utility Board documenting and supporting our assessment of Centra's existing COSS methods in conformance with the regulatory requirements of the MPUB. Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. Centra's 2022 rate application based on the recommendations in our report was approved by the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021, 2022 - 2023)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission (MPSC) and North Dakota Public Service Commission (NDPSC). Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC. Mr. Amen provided electric cost of service, class revenue apportionment, rate design, and expert witness support in Montana-Dakota's 2022 general rate cases before the NDPSC and MPSC. The cases resulted in settlements approved by the respective Commissions.

Chesapeake Utilities Corporation (2020 – 2021)

Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)
Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives, and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)
Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)
Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)
Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018, 2022)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently providing cost of service and rate design for the 2023 – 2024 rate filing. Future project work involves innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities.
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions.
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model, and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)
For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)
Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)
Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)
Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate

design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)
Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)
Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)
Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)
Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert

witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)
Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)
In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr. Amen sponsored expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement in the 2020 general rate case.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)
Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)
Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)
Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)
Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Maine Public Utilities Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
Embedded Class Cost of Service Study
Proposed Revenue Allocation

	Total South Dakota	Total Residential	Total Small Firm General	Total Large Firm General	Total Small Interruptible	Total Large Interruptible
Revenue to Cost Ratio Under Current Rates	0.73	0.67	0.68	0.98	1.12	0.73
Revenues at Equalized Rates of Return						
Revenue Increase	$7,418,636	$6,403,545	$832,689	$81,044	($18,520)	$119,878
Total Revenue at Equalized Rates of Return	27,086,417	19,661,690	2,589,203	4,233,526	156,375	445,623
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00
Scenario A: Equal Percentage Increase (System Average)						
Revenue Increase	7,418,636	5,000,933	662,552	1,566,304	65,970	122,870
Total Revenue at System Average	27,086,417	18,259,078	2,419,066	5,718,786	240,865	448,615
Percent Increase	37.72%	37.72%	37.72%	37.72%	37.72%	37.72%
Parity Ratio	1.00	0.93	0.93	1.35	1.54	1.01
Scenario B: Narrow the disparity of revenue to cost ratio between the classes						
Percent of System Average Increase		120%	120%	33%	9%	100%
Revenue Increase	7,418,636	5,980,838	792,375	516,880	5,673	122,870
Total Revenue	27,086,417	19,238,983	2,548,889	4,669,362	180,568	448,615
Percent Increase	37.72%	45.11%	45.11%	12.45%	3.24%	37.72%
Parity Ratio	1.00	0.98	0.98	1.10	1.15	1.01
% Increase incl Cost of Gas	11.1634%	15.8861%	12.5522%	2.5621%	1.8969%	6.0790%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RESIDENTIAL GAS SERVICE RATE 60 BILL COMPARISON
Pro Forma 2023

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	12.4	$111.58	$121.78	$10.20	9.14%
February	10.1	91.79	100.79	9.00	9.80%
March	10.5	95.90	105.73	9.83	10.25%
April	6.4	61.79	70.55	8.76	14.18%
May	4.0	42.29	50.83	8.54	20.19%
June	1.5	21.37	29.17	7.80	36.50%
July	1.0	17.55	25.50	7.95	45.30%
August	1.0	17.55	25.50	7.95	45.30%
September	1.0	17.25	24.95	7.70	44.64%
October	2.5	29.92	38.17	8.25	27.57%
November	6.0	58.49	67.18	8.69	14.86%
December	9.9	90.96	100.67	9.71	10.68%
Total	66.3	$656.44	$760.82	$104.38	15.90%

Average Increase per Month $8.70

RATE 60	Current 1/	Proposed 2/
Basic Delivery Charge	$0.30	$0.55
Distribution Delivery	$1.836	$2.034
Cost of Gas	$6.412	$6.412

1/ Distribution rates effective with service rendered on and after December 1, 2019. Docket No.GE17-003 and weighted cost of gas for 2023.
2/ Cost of gas equals weighted cost of gas for 2023.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
Bill Comparison Annual Effects
Residential Rate 60

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Monthly Use	Range	Customers	Total Customers	Average Monthly Use
<= $0	0	0	-	<= 0%	0	0	-
>$0 to <=$50	5	5	2.8	>0% to <=5%	33	33	43.6
>$50 to <=$60	7	12	1.3	>5% to <=10%	3,715	3,748	13.6
>$60 to <=$70	21	33	2.9	>10% to <=15%	18,985	22,733	7.6
>$70 to <=$80	530	563	2.4	>15% to <=20%	16,344	39,077	5.0
>$80 to <=$90	1,063	1,626	4.0	>20% to <=25%	6,702	45,779	3.5
>$90 to <=$100	9,870	11,496	2.7	>25% to <=30%	2,372	48,151	2.5
>$100 to <=$110	29,157	40,653	5.6	>30% to <=35%	1,090	49,241	2.0
>$110 to <=$120	8,660	49,313	9.4	>35% to <=40%	640	49,881	1.4
>$120 to <=$130	1,610	50,923	13.6	>40% to <=45%	459	50,340	1.0
>$130 to <=$140	388	51,311	17.9	>45% to <=50%	262	50,602	1.0
> than $140	200	51,511	27.1	> than 50%	909	51,511	0.0

Current Rates

BSC (per day)	$	0.30
Distribution Charge	$	1.836
Cost of Gas	$	6.412

Proposed Rates

BSC (per day)	$	0.55
Distribution Charge	$	2.034
Cost of Gas	$	6.412

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE
(< 500 Cubic Feet Per Hour Meters)

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	26.0	$207.94	$225.62	$17.68	8.50%
February	21.0	169.58	184.66	15.08	8.89%
March	21.8	177.11	193.28	16.17	9.13%
April	12.9	111.21	123.93	12.72	11.44%
May	7.4	71.38	82.40	11.02	15.44%
June	1.9	30.45	39.23	8.78	28.83%
July	0.8	22.92	31.58	8.66	37.78%
August	0.8	22.92	31.58	8.66	37.78%
September	0.8	22.37	30.76	8.39	37.51%
October	4.2	47.89	57.76	9.87	20.61%
November	11.9	103.87	116.23	12.36	11.90%
December	20.5	167.56	183.27	15.71	9.38%
Total	130.0	$1,155.20	$1,300.30	$145.10	12.56%

Average Increase per Month $12.09

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$0.55	$0.82
Distribution Delivery	$0.930	$1.288
Cost of Gas	$6.412	$6.412

1/ Distribution rates effective with service rendered on and after December 1, 2019. Docket No.GE17-003 and weighted cost of gas for 2023.
2/ Cost of gas equals weighted cost of gas for 2023.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
Bill Comparison Annual Effects
Small Firm General Gas Rate 70

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Monthly Use	Range	Customers	Total Customers	Average Monthly Use
<= $0	0	0	-	<= 0%	0	0	-
>$0 to <=$50	0	0	-	>0% to <=10%	1,124	1,124	30.5
>$50 to <=$75	6	6	0.7	>10% to <=15%	1,591	2,715	11.7
>$75 to <=$100	236	242	0.8	>15% to <=20%	999	3,714	6.0
>$100 to <=$125	1,642	1,884	3.6	>20% to <=25%	502	4,216	3.6
>$125 to <=$150	1,297	3,181	8.9	>25% to <=30%	271	4,487	2.3
>$150 to <=$175	722	3,903	14.6	>30% to <=35%	164	4,651	1.4
>$175 to <=$200	433	4,336	20.6	>35% to <=40%	96	4,747	1.0
>$200 to <=$250	390	4,726	28.5	>40% to <=45%	84	4,831	0.2
>$250 to <=$300	142	4,868	40.5	>45% to <=50%	150	4,981	0.0
>$300 to <=$350	49	4,917	52.2	>50% to <=55%	0	4,981	-
> than $350	64	4,981	80.1	> than 55%	0	4,981	-

Current Rates		
BSC (per day)	$	0.55
Distribution Charge	$	0.930
Cost of Gas	$	6.412

Proposed Rates		
BSC (per day)	$	0.82
Distribution Charge	$	1.288
Cost of Gas	$	6.412

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE
(> 500 Cubic Feet Per Hour Meters)

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	200.4	$1,566.90	$1,602.94	$36.04	2.30%
February	164.6	1,291.25	1,321.31	30.06	2.33%
March	172.6	1,356.76	1,388.58	31.82	2.35%
April	112.4	900.03	922.52	22.49	2.50%
May	76.7	631.86	649.09	17.23	2.73%
June	39.4	348.22	359.61	11.39	3.27%
July	32.6	298.50	309.04	10.54	3.53%
August	32.6	298.50	309.04	10.54	3.53%
September	32.2	293.80	304.09	10.29	3.50%
October	55.5	471.60	485.62	14.02	2.97%
November	106.0	851.65	873.17	21.52	2.53%
December	163.4	1,287.22	1,317.64	30.42	2.36%
Total	1,188.4	$9,596.29	$9,842.65	$246.36	2.57%

Average Increase per Month $20.53

RATE 70	Current 1/	Proposed 2/
Basic Delivery Charge	$1.68	$1.86
Distribution Delivery	$1.147	$1.299
Cost of Gas	$6.412	$6.412

1/ Distribution rates effective with service rendered on and after December 1, 2109 Docket No.GE17-003, weighted cost of gas for 2023.
2/ Cost of gas equals weighted cost of gas for 2023.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - SOUTH DAKOTA
Bill Comparison Annual Effects
Large Firm General Gas Rate 70

Overall Annual Effect in Dollars				Overall Annual Effect by Percent			
Range	Customers	Total Customers	Average Monthly Use	Range	Customers	Total Customers	Average Monthly Use
<= $0	0	0	-	<= 0%	0	0	-
>$0 to <=$100	265	265	9.0	>0% to <=5%	1,799	1,799	116.1
>$100 to <=$200	918	1,183	43.8	>5% to <=6%	68	1,867	10.7
>$200 to <=$300	389	1,572	97.3	>6% to <=7%	21	1,888	6.8
>$300 to <=$400	154	1,726	153.2	>7% to <=8%	8	1,896	3.8
>$400 to <=$500	84	1,810	211.3	>8% to <=9%	15	1,911	2.5
>$500 to <=$750	85	1,895	288.6	>9% to <=10%	24	1,935	1.0
>$750 to <=$1000	31	1,926	446.5	>10% to <=11%	41	1,976	0.1
>$1000 to <=$1250	17	1,943	578.5	>11% to <=12%	0	1,976	-
>$1250 to <=$1500	8	1,951	690.5	>12% to <=13%	0	1,976	-
>$1500 to <=$2000	12	1,963	896.5	>13% to <=14%	0	1,976	-
> than $2000	13	1,976	1,805.7	> than 14%	0	1,976	-

Current Rates		
BSC (per day)	$	1.68
Distribution Charge	$	1.147
Cost of Gas	$	6.412

Proposed Rates		
BSC (per day)	$	1.86
Distribution Charge	$	1.299
Cost of Gas	$	6.412

MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23-____

Direct Testimony

Of

Stephanie Bosch

Q. Please state your name and business address.

A. My name is Stephanie Bosch, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with **Montana-Dakota Utilities Co.?**

A. I am the Regulatory Affairs Manager for Montana-Dakota Utilities Co. (Montana-Dakota).

Q. Would you please describe your duties as Regulatory Affairs Manager?

A. I am responsible for the proper application of the Company's gas and electric rates in the Customer Care and Billing System (CC&B), the application of tariffs, and the preparation of miscellaneous rate filings.

Q. Would you please describe your education and professional background?

A. I graduated from the University of North Dakota in 1995 with a Bachelor of Business and Public Administration degree in Banking and Financial Economics. I joined Montana-Dakota in June 1997 as a Rate

Clerk in the Regulatory Affairs Department and realized positions of increasing responsibility within the Regulatory Affairs Department until 2011 when I left the Company. In 2013 I returned to the Company as a Regulatory Analyst before attaining my current position in August of 2015.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the pro forma revenues, as included in Statement I of this Application, the proposed rate schedules provided in Appendix B to the Application, and other proposed changes to the Company's gas tariff.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before the Public Service Commissions of Montana, North Dakota, and Wyoming and the Public Utilities Commission of Minnesota.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement I pages 7 through 19 and the proposed rate schedules provided in Appendix B to the Application.

Pro Forma Revenue Analysis

Q. Would you please explain the pro forma revenues included in Statement I pages 7 through 19?

A. Yes, as shown on the referenced pages, Montana-Dakota applied the Basic Service Charges and Distribution Delivery Charges applicable under each rate schedule, as first authorized in Docket No. NG15-005 and later updated to reflect the impact of the Tax Cuts and Jobs Act of 2017 in Docket No. GE17-003, to the number of pro forma customers and use, identified by Mr. Bensen, to derive the Company's pro forma revenues. Interruptible Sales and Transportation customers were priced at each applicable rate schedule's maximum Distribution Delivery Charge unless service is provided under a contract rate. The Cost of Gas rates used are reflective of the commodity gas rate for 2023 and demand costs as of March 2023, excluding any surcharges.

Proposed Tariff Changes

Q. The Company is proposing two new rate schedules. Please describe the first of the two new rate schedules being proposed, Firm General Contracted Demand Service Rate 74, provided here as Exhibit No. ____(SB-1).

A. Montana-Dakota is proposing a new rate schedule titled Firm General Contracted Demand Service Rate 74 (Rate 74) which will be applicable to non-residential customers with standby natural gas generators or customers who qualify under the Company's interruptible service tariffs, but have requested, and received Company approval, for firm gas service under the proposed rate schedule.

The purpose of the new rate schedule is to recover capacity related costs from (1) standby use customers whose gas consumption is intermittent and do not, at this time, provide adequate recovery of these costs and (2) customers who otherwise qualify for service under the Company's interruptible service rates due to their natural gas requirements but who want the option of reserving capacity for firm service. Interruptible customers requesting firm gas service under Rate 74 will need approval from the Company prior to the commencement of service under this rate in order to determine that adequate capacity is available for firm service for the requesting customer.

The proposed rate consists of four components: a Basic Service Charge, a Distribution Demand Charge, a Capacity Charge, and a Cost of Gas Commodity Charge. The Basic Service Charge reflects the same level of Basic Service Charges applicable under the Company's Firm General Service Rate 70 schedules. The Distribution Demand Charge is a new billing component for Montana-Dakota and is designed to recover the distribution demand-related costs from these customers. Customers will consult with the Company, prior to service under this rate, to determine the connected load (or demand Dk) applicable to their service that the Distribution Demand Charge will then be applied to each month.

The Cost of Gas is separated into two billing components: a Capacity Charge and a Cost of Gas Commodity Charge, as discussed by Ms. Vesey. The Capacity Charge will be applied to the contracted monthly billing demand Dk and the Cost of Gas Commodity Charge will be applied to the customer's actual measured Dk.

Q. Please explain the calculation of the proposed Distribution Demand Charge.

A. The Company calculated the proposed Distribution Demand Charge rate of $8.00 per monthly demand Dk utilizing the results of the Company's class cost of service study. As identified in Schedule N-1 of Statement N, the Company's total distribution demand-related costs are $8,287,683. In dividing those costs by the Company's peak day deliveries of 86,484 Dk, an annual demand cost per Dk of $95.83 is calculated, which in turn, equates to a monthly rate of $8.00 per demand Dk.

Q. The second new rate schedule is Summary Billing Plan Rate 115. Please briefly explain that new rate schedule which is provided as Exhibit No. ___(SB-2).

A. Summary Billing Plan Rate 115 (Rate 115) is an optional billing arrangement where qualifying customers that have multiple premises in South Dakota can choose to consolidate the billing of those premises under one account. The new rate schedule outlines the general availability of this new billing arrangement as well as the terms and conditions for enrolling in and maintaining eligibility under the plan.

The proposed rate schedule is in response to customers requesting the ability to consolidate their multiple monthly Montana-Dakota bills into one account which in turn equates to one monthly bill with one payment. The Company recognizes the value of a bill consolidation program for participating customers; however, believes such an optional billing arrangement is best managed through a defined program that helps inform interested and participating customers of their responsibilities as well as the Company's parameters for continued participation in the plan.

Q. Would you briefly describe any additional changes the Company is proposing to the Company's gas tariff?

A. The Company is proposing the following changes to its gas tariff as clearly identified in the legislative copy of the tariff provided in Appendix B of the Application:

- The Company is proposing an entirely new volume of its gas rate book, designated herein as SDPUC Volume 3, to supersede the current Volume 2, in order to reflect the removal of "A Division of MDU Resources Group, Inc." in the tariff header of all rate schedules.
- The rates described by Mr. Ron Amen have been incorporated into the proposed rate schedules.
- Clarify that the charges included in the determination of a penalty payment as provided for under the Penalty for Failure to Curtail or

Interrupt provision applicable under the Company’s Interruptible Service Rates 71 and 85 and Transportation Rates 81 and 82 tariffs. The proposed tariff language clarifies that all charges billed under the Company’s Firm General Service Rate 70, excluding the Basic Service Charge, are billed on any gas taken in the event of a penalty situation.

- Update the metering requirements provision under the Company’s Interruptible Service Rates 71 and 85 schedules to bring them in line with the metering requirement provisions under Montana-Dakota’s Transportation rate schedules applicable today.
- Update select definitions included in the Company’s Distribution Delivery Stabilization Mechanism Rate 87 schedule to reflect components from this rate case. The first definition updated is the 30-year average for normal degree days to reflect the same 30 years used to normalize the Company’s volumes. The second definition updated is the Temperature Sensitive Use per Customer to reflect the daily base use per customer per day resulting from the applicable rates’ regression analyses performed for normalizing firm volumes in this case.
- Reflect the proposed changes to the Purchased Gas Cost Adjustment Rate 88 schedule as described in the direct testimony of Ms. Vesey.

- Introduce new or update existing provisions within the Company's General Provisions Rate 100 that:
    - Allows the Company to turn a customer's gas meter on and, if no gas use is detected at that time, leave the gas meter on and permit the customer to relight any pilot lights on their equipment at the customer's earliest convenience. This will eliminate the required presence of the customer at the time of a gas meter turn on, if the requesting customer consents to and accepts responsibility for their pilot relight(s). (Rate 100, Section IV.2 Liability/Customer's Equipment)
    - Introduce a monthly Manual Meter Reading Charge assessed customers who request to have their gas meter read manually each month in lieu of the Company installing an AMR-equipped meter to obtain meter reads. (Rate 100, Section V.14 General Terms and Conditions/Manual Meter Reading Charge)
    - Update the annual authorized usage by rate used in the determination of the Non-Residential Reconnection Fee for Seasonal or Temporary Customers to reflect each respective rate class's average annual use from this docket. (Rate 100,

Section V.20 General Terms and Conditions/Reconnection Fee for Seasonal or Temporary Customers)

Also update the Seasonal Reconnection provisions to include in their determination the Expansion Customer Charges, under North Deadwood Area Surcharge Rate 75, which would have been applicable during the period service was not being used. The inclusion of these charges in the seasonal reconnection fee eliminates the delay and/or shifting of costs being recovered under Rate 75 that would result from seasonal customers stopping service and therefore not contributing to the recovery of the Rate 75 project during their absence.

- Advise customers that over time rates will apply if the customer’s call is received after 12:00 p.m. local time for service work to be performed after hours on that same workday. To avoid over time rates, a customer may schedule the service work for a future workday. (Rate 100, Section V. 21 Discontinuance of Service for Nonpayment of Bills.) This will provide a consistency regarding the timing of calls received for customers requesting service work under Paragraph V.16

Utility Services Performed after Normal Business Hours and that included in Paragraph V. 21 Discontinuance of Service for Nonpayment of Bills.

  - Summarize the rules regarding billing adjustments necessary, due to metering or other errors, in order to provide a point of reference for both Company personnel and customers. (Rate 100, Section V.26 General Terms and Conditions/Billing Adjustments)

- Revise the Maximum Allowable Investment (MAI) formula used to determine a firm extension project's cost participation under Firm Gas Service Extension Policy Rate 120 in order to recognize the charges billed under proposed Firm General Contracted Demand Rate 74 includes a Distribution Demand Charge, not a Distribution Delivery Charge.

- Modify Meter Data and Privacy Policy Rate 140 to allow the Company to release aggregated and/or anonymized data for multiple customers to third parties that have a qualifying business purpose such as for energy efficiency and/or conservation or HUD compliance. Third parties requesting data will need to submit a new form, Authorization Form for Aggregated/Anonymized Energy Consumption Data included on Sheet No. 16 in Section 6 of the

Company's gas tariff, which will be reviewed by Company personnel for accuracy prior to the release of any information. No identifiable customer information will be provided in response to the request. The Company will only provide customer identifying information upon receipt of each customer's written authorization.

- There are other minor wording changes listed throughout the Company's rate book to improve the readability of the rate without modifying any conditions, update the rate and/or page references or are self-explanatory. These changes are clearly denoted on the tariff sheets in the legislative format.

Q. Section 6 of the Company's gas tariff includes a number of sample forms used by the Company. Did Montana-Dakota review its sample forms in preparation for this rate case?

A. Yes, a complete form review was performed to ensure the sample forms included in Section 6 of the Company's gas tariff reflect the current forms the Company is using to communicate with customers and/or reflective of any new agreements or forms used by Montana-Dakota. Some forms, included in Appendix B, reflect minor changes from those included in the Company's current tariff, such as the overall appearance of the form and/or language changes that do not modify the intent of the form, but were made for readability, clarification, etc. Other forms were found to no longer be used in South Dakota or are new since the Company's last sample form review in Docket No. GE19-004.

Q. Does this conclude your testimony?

A. Yes.

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 3

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Availability: N

In all communities served applicable to non-residential customers with standby natural gas generators and, available on an optional basis to, customers qualifying for service under the interruptible service tariffs that have requested, and received approval from the Company, for gas service under this rate.

Rate:

Basic Service Charge:

For customers with meters rated under 500 cubic feet per hour	$0.82 per day
For customers with meters rated over 500 cubic feet per hour	$1.86 per day

Distribution Demand Charge:	$8.00 per dk per month of billing demand
Capacity Charge per Monthly Demand dk:	Determined Monthly – See Rate Summary Sheet for Current Rate
Cost of Gas: Commodity per dk:	Determined Monthly – See Rate Summary Sheet for Current Rate

Minimum Bill:

Basic Service Charge, Distribution Demand Charge, and Capacity Charge.

Payment:

Billed amounts will be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate 100, §V.12, or any amendments or alterations thereto.

Determination of Monthly Billing Demand:

Customer's billing demand will be determined in consultation with the Company. Customer's actual demand will be reviewed annually and, if warranted, a new monthly billing demand established.

N

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 3

FIRM GENERAL CONTRACTED DEMAND SERVICE Rate 74

Cost of Gas: N

The cost of gas includes all applicable cost of gas items as defined in Purchased Gas Cost Adjustment Rate 88 or any amendments or alterations thereto. The cost of gas component is subject to change on a monthly basis.

Metering Requirements:

1. Service provided for under tariff must be separately metered from customer's other gas services.

2. Remote data acquisition equipment (telemetering equipment) may be required by the Company for a single customer installation for daily measurement.

3. Customer may be required, upon consultation with the Company, to contribute towards any additional metering equipment necessary for daily measurement by the Company, depending on the location of the customer to the Company's network facilities. Enhancements and/or modifications to these services may be required to ensure equipment functionality. Such enhancements or modifications shall be completed at the direction of the Company with all associated costs the Customer's responsibility. Any interruption in such services must be promptly remedied or service under this tariff will be suspended until satisfactory corrections have been made.

4. Consultation between the customer and the Company regarding telemetering requirements shall occur prior to meter installation.

General Terms and Conditions:

1. Customers with standby gas generators required to take service under this schedule are not required to execute a contract. Other customers choosing to take service under this schedule will be required to execute a contract applicable for a minimum period of one year.

2. The foregoing schedule is subject to Rates 100 through 140 and any amendments or alterations therefore or additional rules and regulations promulgated by the Company under the laws of the state. N

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 3

SUMMARY BILLING PLAN Rate 115

Availability:

N

Under the Company's Summary Billing Plan, customers are provided an optional billing arrangement under which a customer's multiple premises may be consolidated into one billing statement each month. This billing arrangement is available in all communities served by the Company for customers who voluntarily agree to participate in the Summary Billing Plan and who continue to meet the availability and terms and conditions of the plan.

The Company may limit the number of premises participating in the plan and exclude services based on rate and/or customer class or credit standing with the Company. Seasonal, short-term, or temporary customers will not be allowed to enroll. Participation in other optional programs such as Balanced Billing may also limit a customer's ability to participate in this billing arrangement. This is not an all-inclusive list of exclusions and service enrollment is at the Company's sole discretion.

General Terms and Conditions:

1. A customer requesting Summary Billing must provide 45 days advanced notice of their request to enroll.

2. Customer agrees to contract for Summary Billing for a minimum of one year.

3. Each service enrolled in the Summary Billing Plan shall be billed at the otherwise applicable rate schedule.

4. The Company, at its sole discretion, will select the bill date for an enrolled customer's Summary Bill.

5. Enrolled customers need only make one payment each month covering the total amount due for all services included in the Summary Bill.

6. Payment policies remain in effect for each customer participating in the plan. Any determination of delinquencies will be based on the bill date of the Summary Bill.
    a. If a customer participating in the Summary Billing Plan falls into arrears, the Company, at its sole discretion, may discontinue this optional billing arrangement and revert the services into separate billing statements.

N

Montana-Dakota Utilities Co.
400 N 4th Street
Bismarck, ND 58501

State of South Dakota
Gas Rate Schedule – SDPUC Volume No. 3

Section 5
Original Sheet No. 13.1

SUMMARY BILLING PLAN Rate 115

7. Either the customer or the Company may cancel a customer's Summary Billing Plan with a 45-day advanced notice of cancellation. Upon cancellation of the plan, a customer's services will revert into separate billing statements. N
    a. Upon cancellation of a Summary Billing Plan, the customer may not request the establishment of a new Summary Billing Plan for at least one year after cancellation.

8. The Company will not be liable for any customer costs which may result from any refusals, delays or failures resulting from requests for, or changes to, a customer's Summary Billing Plan. N