BEFORE THE

PUBLIC UTILITIES COMMISSION

STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO. FOR AUTHORITY TO INCREASE ITS NATURAL GAS RATES

DOCKET NO. NG12-008

TESTIMONY & EXHIBITS OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

OCTOBER 1, 2013

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is David E. Peterson. I am a Senior Consultant employed by Chesapeake Regulatory Consultants, Inc. ("CRC"). Our business address is 1698 Saefern Way, Annapolis, Maryland 21401-6529. I maintain an office in Dunkirk, Maryland.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I graduated with a Bachelor of Science degree in Economics from South Dakota State University in May of 1977. In 1983, I received a Master's degree in Business Administration from the University of South Dakota. My graduate program included accounting and public utility courses at the University of Maryland.

In September 1977, I joined the Staff of the Fixed Utilities Division of the South Dakota Public Utilities Commission as a rate analyst. My responsibilities at the South Dakota Commission included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric, gas and telephone utilities.

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, wastewater, and steam utilities in connection with utility rate and certificate proceedings before federal and state regulatory commissions.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes. I have presented testimony in 141 other proceedings before the state regulatory commissions in Alabama, Arkansas, California, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

In addition, in 2006 testified twice before the Energy Subcommittee of the Delaware House of Representatives on consolidated tax savings and income tax normalization. Also in 2006, I presented a one-day seminar to the Delaware Public Service Commission ("Commission") on consolidated tax savings, tax normalization and other utility-related tax issues. In the spring of 2011, I co-presented along with Mr. Scott Hempling, the then-director of NRRI, a three-day seminar on public utility ratemaking principles to the Commissioners and Staff of the Washington Utilities and Transportation Commission. In 2012, I presented a one-day seminar on cost allocation and rate design to the Colorado Office of Consumer Counsel and a three-day seminar on public utility ratemaking, revenue requirements, cost allocation and rate design to the Staff of the Delaware Public Service Commission.

II. SUMMARY

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this proceeding is on behalf of the South Dakota Public Utilities Commission Staff ("Commission Staff").

Q. HAVE YOU TESTIFIED IN OTHER PROCEEDINGS BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION ("COMMISSION')?

A. Yes, I have. I testified in several South Dakota rate proceedings in the late 1970's when I was on the Commission Staff. More recently, I presented testimony to the Commission in Docket No. EL12-046 involving a rate increase application filed by Northern States Power Company. In addition, I have assisted the Commission Staff in analyzing virtually all of the major utility rate applications during the past several years.

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

A. I was asked to assist the Commission Staff in analyzing Montana-Dakota Utilities Co. ("MDU" or "the Company") proposed rate changes for South Dakota retail natural gas distribution service. Specifically, I am presenting the Commission Staff's recommendations on MDU's proposed adjustments to test year labor costs, employee benefits, and insurance expense. I also present my determination of MDU's cash working capital requirement based on a lead-lag analysis. In addition, my testimony raises an issue relating to the cost of gas being produced at the Billings Landfill and addresses MDU's class cost of service study, the proposed spread of the rate increase among rate classes, MDU's margin sharing plan for sales made to grain dryers, rate consolidation between the Black Hills and East River areas, and MDU's proposed Basic Service Charge.

Q. ARE YOU FAMILIAR WITH MDU'S FILING IN THIS PROCEEDING?

A. Yes, I am. I have carefully reviewed the Direct Testimonies, Exhibits and workpapers sponsored by the Company's witnesses relating to the issues that I address herein. I also reviewed the Company's responses to the Commission Staff's data requests, again relating to issues that I address in my testimony.

Q. PLEASE PROVIDE A SHORT SUMMARY OF YOUR RECOMMENDATIONS TO THE COMMISSION IN THIS PROCEEDING.

A. Following are my recommendations to the Commission on the issues for which I am responsible in this proceeding.

- **Labor Costs – Incentive Compensation:** MDU's adjustments to reflect a 2.50 percent increase for union employees effective May 2013 and a 3.0 percent increase for non-union employees effective in December 2012 are known and measurable. Those adjustments should be accepted by the Commission. However, the Commission should reject that portion of MDU's proposed labor adjustment (Adjustment No. 6) relating to incentive compensation. All incentive compensation should be excluded from MDU's revenue requirement. Excluding rate recognition for incentive compensation costs reduces MDU's requested payroll allowance by $354,288. My adjustment to test year payroll expenses, which excludes incentive compensation and bonuses, is detailed in Exhibit___(DEP-3).

- **Employee Benefits Expense:** The Commission should reject MDU's proposed employee benefits expense adjustment (Adjustment No. 7) in its entirety because it is speculative in that it is based on MDU's budget projections rather than known and measurable changes in the Company's costs. Rejecting MDU's proposed employee benefits expense adjustment increases MDU's claimed operating expenses by $45,077. The increase results primarily because MDU budgeted for 2013 a reduction in the Company's post-retirement benefits cost.

- **Insurance Expense:** The Commission should reject MDU's proposed insurance expense adjustment (Adjustment No. 14) in its entirety because it is speculative in that it is based on MDU's budget projections rather than known and measurable changes in the Company's insurance costs. Rejecting MDU's proposed insurance expense adjustment decreases the Company's claimed operating expenses by 4,493.

- **Billings Landfill Gas Costs:** Ratepayers should not be burdened with the extraordinarily high cost that MDU is requesting in this filing for gas produced at the Billings, Montana landfill site. Rather, cost recovery should be capped at $6.701 per dekatherm ("dkt") and be recovered through the Company's periodic PGA filings. Thus, the rate base and operating expenses related to the Company's gas producing facilities at the Billings landfill site reflected in MDU's filing should be eliminated from the base rate cost of service determination.

- **Cash Working Capital:** A utility's cash working capital requirement should be measured by a lead-lag study. Rather than performing a lead-lag analysis, however, MDU simply did not include a rate base allowance for cash working capital. Because current data from the Company concerning the timing of revenues and expenses were not available, which would have enabled me to prepare my own lead-lag study, I used the lead-lag analysis prepared by the Commission Staff in MDU's previous South Dakota gas rate case (SDPUC Docket No. NG04-004) and updated that analysis for the Company's current revenue and expense levels. My analysis, summarized on my Exhibit___(DEP-1), shows that MDU's cash working capital requirement is $(357,245). This amount should be deducted from MDU's proposed rate base.

- **Rate Consolidation:** Commission should adopt the consolidation of rates between MDU's Black Hills and East River areas, as proposed by MDU.

- **Class Cost of Service Study – Spread of the Increase:** The Commission should accept MDU's class cost of service study. The Commission should also accept MDU's proposed spread of the increase because it moves each rate class closer to its cost of service. However, the Company's proposed spread must be modified because the Commission Staff is recommending a $1,393,261 revenue decrease rather than the $1,547,999 increase that

MDU requested. Therefore, I used essentially the same gradualism guidelines that are reflected in MDU's proposed spread to establish class revenue targets based on the Commission Staff's recommended revenue decrease. I recommend that the Commission adopt my recommended spread of the revenue decrease among the rate classes as illustrated in Exhibit___(DEP-4), Schedule 2.

- **Margin Sharing:** The Commission should adopt the net margin sharing plan proposed by MDU on sales to grain dryers. Under this plan, sales to grain dryers are excluded from MDU's base rate determination. Instead, MDU will return to South Dakota customers 90 percent of net margins (revenues minus the cost of gas) earned on all sales to grain dryers through the periodic PGA.

- **Customer Service Charge:** The Commission should reject MDU's proposed increases in the Basic Service Charge. MDU's proposed charges exceed the customer-related cost of service. Also, now is a particularly inopportune time for a large increase in the Basic Service Charge in that the Commission Staff has determined MDU's revenues under existing rates are excessive and that rates should be reduced. Therefore, I recommend that the Basic Service Charges be consolidated within the two existing service territories by increasing those charges in the East River service territory to the existing levels in the Black Hills area. The Basic Service Charges should not be increased beyond present levels in the Black Hills service territory, however, at this time.

The bases for my recommendations above are explained in the following sections of my testimony.

Q. WERE YOU ASKED TO ANALYZE ANY OTHER ASPECTS OF MDU'S RATE FILING?

A. Yes, I was. In addition to the issues that I previously summarized and for which I sponsor specific recommendations, I also analyzed the following aspects of MDU's rate filing:

- Other tax deductions (Adjustment No. 23);

- Elimination of closing/filing & prior period adjustment (Adjustment No. 25);
- Unamortized gain/loss on debt (Adjustment E);
- Deferred FAS 106 costs (Adjustment F); and
- Deferred tax normalization (Adjustment J).

I am not challenging any of these adjustments sponsored by MDU and recommend that the Commission accept them.

III. LABOR COSTS – INCENTIVE COMPENSATION

Q. WHAT HAS MS. MULKERN INCLUDED IN MDU'S RATE FILING FOR INCENTIVE COMPENSATION?

A. Ms. Mulkern's proposed South Dakota *pro forma* labor cost allowance includes approximately $354,288, based on the South Dakota gas share of the three-year average of bonuses and incentive compensation payments made during the years 2010 through 2012.

Q. IS IT APPROPRIATE FOR THE COMPANY TO HAVE INCENTIVE COMPENSATION PLANS?

A. Incentive pay has become prevalent in many industries, including public utilities. Generally, I do not have a problem with utilities motivating key employees through incentive compensation plans. I have not objected to recognizing in rates incentive compensation costs incurred under plans that are designed to promote employee safety and ratepayer interests. On the other hand, I have consistently objected to recognizing in utility rates incentive payments made under plans that were primarily designed to promote shareholder interests (i.e., wealth) rather than ratepayer interests. It is especially objectionable that some incentive compensation plans, including those of MDU, provide perverse incentives for the utility to overstate its revenue requirement and to maintain excessive rates.

Q. IS IT REASONABLE TO CONCLUDE THAT THE PURPOSE OF MDU'S INCENTIVE COMPENSATION PLANS IS TO PROMOTE EMPLOYEE SAFETY AND RATEPAYER INTERESTS RATHER THAN SHAREHOLDER INTERESTS?

A. No, there is no support for that conclusion. The Company's plans are prime examples of where the interests of stockholders are placed far above those of MDU's South Dakota ratepayers. Therefore, it is not appropriate to recognize in rates any costs incurred under the plans because of the way MDU has structured those plans.

MDU provided copies of its incentive compensation plans in effect during the period 2011 through 2013.[1] All of these plans appear to have similar goals in that they use various incentives for motivating employees. For example, the Employee Incentive Plan for 2013 includes the following Plan Overview:

> "The Employee Incentive Plan (Plan) for Utility employees focuses attention on Company objectives and encourages continued improvement in standards for performance that leads to positive business results and benefits our customers.
>
> The Plan is designed to:
>
> - Establish a strong relationship between pay and Company performance
> - Provide focus on Utility strategic initiatives that increase effectiveness and efficiency
> - Promote superior customer service

[1] See MDU's response to Staff Request 9-20.

> - Deliver labor market competitive rewards that attract, retain and motivate talented employees to higher levels of performance
>
> The efforts of employees, both individually and as team members, are key to this success. ***The Plan provides an opportunity for employees to receive additional compensation if pre-established financial results are achieved as well as the achievement of important organizational and customer satisfaction goals***. The Plan year is January 1 through the last business day of the year, normally December 31."[2] [Emphasis supplied]

Under each of MDU's incentive compensation plans, total performance payouts are determined first by how well the Company meets pre-established financial goals in terms of earnings per share or net income less taxes. That is, the plans each place a threshold hurdle on the Company's ability to make performance-related payouts regardless if other financial, safety or operational individual and team goals are met. MDU's utility operating unit must attain at least 85 percent of their "Utility Financial Goal" before ***any*** performance payouts are made. If the financial threshold goals are met, employees are then eligible to earn additional performance payments for meeting or exceeding other pre-established individual financial, group safety and operational goals. But, even if all other individual and team goals are met or exceeded, no incentive payments will be made unless the minimum financial threshold targets have been met.

Q. ON WHAT BASIS DO YOU CONCLUDE THAT THE PLANS ARE PRIMARILY DESIGNED TO PROMOTE STOCKHOLDER INTERESTS RATHER THAN RATEPAYER INTERESTS?

A. There is no reasonable conclusion other than that these Plans are primarily designed to promote shareholder wealth given that they each require MDU to

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[2] Ibid.

achieve a threshold level of earnings or net income before ***any*** incentive payments are made. That is, MDU must first satisfy shareholders by producing sufficient earnings before any employee is rewarded for achieving other financial and operational goals. If MDU were more concerned about providing incentives for achieving public safety or ratepayer service and satisfaction goals, for example, there would be no earnings per share or return thresholds as a necessary pre-condition. Thus, it is clear that the paramount goal of MDU's incentive compensation plan is to increase shareholder wealth. This goal is inconsistent with the ratepayers' goal of receiving service at the lowest reasonable price. In fact, there is a perverse incentive in MDU's incentive compensation plans for the Company to artificially inflate requests for rate relief and to maintain excessive rate levels. Since stockholders are the primary beneficiaries when the Company achieves the financial threshold targets, stockholders rather than South Dakota ratepayers should pay for the incentive awards. Therefore, I recommend that incentive compensation be excluded from MDU's recoverable costs.

Q. HAVE OTHER STATE REGULATORY COMMISSIONS DENIED UTILITIES RECOVERY OF COSTS INCURRED UNDER INCENTIVE COMPENSATION PLANS?

A. Yes. I have not surveyed regulatory practices in all states. I am aware, however, that utilities' incentive compensation payments have been excluded from recoverable expenses by state regulatory commissions in Kentucky,[3] Michigan,[4] Illinois,[5] Missouri,[6] and Delaware.[7] It is also reasonable and appropriate for the

[3] *Re: Union Light, Heat & Power Co.*, 245 PUR 4th 1 (Ky. PSC 2005).
[4] *Re: Consumers Energy Co.*, 2005 WL 3617546 (Mich. Dec. 22, 2005).
[5] *Re: Northern Illinois Gas Company dba Nicor Gas Company*, 245 PUR 4th 194 (Ill. Commerce Comm. 2005).
[6] *Re: Missouri Gas Energy, a Division of Southern Union Co.*, 235 PUR 4th 507 (Mo. PSC 2004), *order clarified* in 2004 WL 2411284 (Mo. Sept. 28, 2004), and *decision clarified on*

Commission to reject Ms. Mulkern's request for recovery of incentive compensation payments.

III. EMPLOYEE BENEFITS

Q. WHAT DID MS. MULKERN PROPOSE FOR EMPLOYEE BENEFITS COSTS?

A. In her Adjustment No. 7, Ms. Mulkern proposed a net $45,077 reduction to test year medical insurance, pension expense, post-retirement benefits, 401-K, worker's compensation insurance and supplemental insurance expenses.

Q. ARE MS. MULKERN'S EMPLOYEE BENEFITS EXPENSE ADJUSTMENTS KNOWN AND MEASURABLE?

A. No, they are not. Rather, Ms. Mulkern's *pro forma* employee benefits expenses reflect the Company's 2013 budget for these costs rather than actual, known changes from test year levels. Because budgeted amounts do not meet the known and measurable standard upon which the Commission has relied for evaluating *pro forma* expense adjustments, I recommend that Ms. Mulkern's employee benefits adjustment be rejected.

IV. INSURANCE EXPENSE

Q. HAVE YOU REVIEWED MS. MULKERN'S PROPOSED ADJUSTMENT NO. 14 FOR INSURANCE EXPENSES?

denial of rehearing, 2004 WL 2434227 (Mo. PSC Oct. 19, 2004).

[7] *Re: Delmarva Power & Light Company,* Del. PSC Docket No. 05-304, Order No. 6930, June 7, 2006.

A. Yes, I have. Ms. Mulkern proposed a $4,493 adjustment to test year insurance expenses. As with her employee benefits adjustment, Ms. Mulkern's insurance expense adjustment relies on the Company's 2013 budget for insurance cost rather than actual, known changes from test year levels. Because her insurance adjustment is speculative and not known and measurable, I recommend that it be rejected.

V. BILLINGS LANDFILL GAS COSTS

Q. MDU'S RATE FILING INCLUDES RATE BASE INVESTMENTS AND OPERATING EXPENSES RELATED TO A GAS RECOVERY OPERATION AT A LAND FILL SITE OWNED BY THE CITY OF BILLINGS, MONTANA. WHAT IS MDU'S INVOLVEMENT IN THE BILLINGS LANDFILL OPERATION?

A. MDU has constructed and owns a methane gas recovery system in a large landfill operated by the City of Billings, Montana. The economic feasibility of the methane recovery system was evaluated by MDU's consultant, Wenck Associates, first in 2007 and later updated in 2009-10. Initial construction was completed and the recovery system was placed into service in December, 2010. MDU pays the City of Billings a royalty equal to 15% of the gas produced and delivered into MDU's distribution system at a price per dekatherm ("dkt") based on an index of natural gas costs for the Rocky Mountain CIG transfer point – the point utilized by MDU to purchase natural gas supply.[8] Operating expenses of the recovery system are incurred by MDU and recorded on MDU's financial statements as gas production expenses; MDU's investment is booked as production plant.

[8] See MDU's response to Staff Request No. 3-15.

Q. HOW DOES MDU PROPOSE TO TREAT THE COSTS THAT IT INCURS AT THE BILLINGS LANDFILL FOR RATEMAKING PURPOSES?

A. Until now, MDU has treated its royalty payments to Billings as a cost of purchased gas in its South Dakota purchased gas adjustment ("PGA') filings. No other costs related to the landfill operation have been reflected either in its base rates or through its South Dakota PGA clause.

With this rate filing, MDU seeks to have its landfill operating expenses and investment-related costs recognized as components of its base rate retail revenue requirement. For the *pro forma* test year ended June 30, 2012, these costs (including its claimed 8.10% on rate base investment) create a base rate revenue requirement of $418,446 that, for the 24,565 dkt of natural gas received from the landfill, represents an average cost of $17.03 per dkt.[9] Adding an allowance for the landfill royalties recovered through the PGA (ranging from $0.36 to $0.58/dkt during the twelve months ended June 30, 2013) results in a total cost to ratepayers in the range of $17.39 to $17.61 per dkt.

Q. HOW DOES THIS CLAIMED COST OF GAS COMPARE WITH MARKET PRICES FROM OTHER SOURCES?

A. During the same period, based on the CIG transfer point index prices used in the agreement with Billings to establish the royalty payments, the market acquisition price of natural gas ranged between $2.40 and $3.87 per dkt.[10] Thus, the Billings Landfill gas cost to ratepayers is at least 4.5 times ($17.39/$3.87) gas costs at prevailing market prices.

[9] See MDU's response to Staff Request No. 3-11.
[10] See MDU's response to Staff Request 7-2, Attachment A.

Q. WERE COSTS OVER MARKET PRICES OF THIS MAGNITUDE EXPECTED WHEN MDU EMBARKED ON THE LANDFILL OPERATION?

A. No, they were not. The claimed production cost of $17.03/dkt greatly exceeds the cost estimates in the feasibility study commissioned by MDU and relied upon to go forward with the project. The consultant's report projected that, if completed in 2010, the cost (revenue requirement) in Year 1 would amount to $6.828/dkt, in Year 3, $6.701/dkt and, averaged over a 30-year life cycle, $5.579/dk.[11] The consultant's originally projected costs are far below the actual costs that MDU is now incurring at the Billing's Landfill.

Q. HOW SHOULD THE COMMISSION TREAT THE COST OF GAS RECEIVED FROM THE BILLINGS LANDFILL OPERATIONS FOR RATEMAKING PURPOSES?

A. Ratepayers should not be burdened with the extraordinarily high costs that MDU is requesting in this filing for the landfill production. These costs resulted entirely from decisions made by MDU with expectations that it has failed to achieve. Accordingly, and until such time as cost of service pricing is brought into line with either prevailing market prices measured by the CIG Index ($3.58/dkt in June, 2013) or the feasibility study expectations ($5.579/dkt 30-year average or $6.701 Yr. 3 cost level), I recommend that cost recovery be limited to one of these levels with a preference for the $6.701/dkt cost anticipated for Year 3 in the feasibility study. Use of the Year 3 cost matches, approximately, the rate-effective period in this case, 2013 being the third year of the landfill operation that began in 2010.

[11] See MDU's response to Staff Request No. 3-13, Attachment D (pdf. P. 194/200).

Using the CIG Index would have the appeal of following the prevailing market prices but it presumes, unreasonably, an ability to develop a source of supply with costs that will follow these potentially volatile prices over a long period of time. Use of the Year 3 estimated cost rather than the 30-year average costs developed in the feasibility study recognizes that cost of service pricing tends to result in higher costs in the early years of production because of a higher-than-average, nearly undepreciated rate base.

Q. WHAT MECHANISM FOR COST RECOVERY DO YOU RECOMMEND?

A. Cost recovery for South Dakota ratemaking purposes should be capped at the Year 3 level and be recovered through the Company's periodic PGA filings. Thus, the claimed rate base and operating expenses reflected in MDU's filing should be eliminated from the base rate cost of service determinations. I have asked Ms. Mehlhaff to reflect this treatment in her revenue requirement model.

VI. CASH WORKING CAPITAL

Q. FOR WHAT PURPOSE SHOULD A CASH WORKING CAPITAL ALLOWANCE BE INCLUDED IN A UTILITY'S RATE BASE?

A. A cash working capital allowance should be included in rate base to compensate investors for investor-supplied funds, if any, used to provide the day-to-day cash needs of the utility. These cash needs are measured in a lead-lag study. Specifically, a lead-lag study measures the time between (1) the provision of service to utility customers and the receipt of revenue for that service by the utility, and (2) the provision of service by the utility and its disbursements to employees and vendors in payment for the associated cost of those services. The difference between the revenue "lag" and the expense "lead" is expressed in days. The difference, which can be either a net lag or a net lead, multiplied by the average daily cash operating expenses, quantifies the cash working capital required for, or available from utility operations.

Q. DID MDU PREPARE A LEAD-LAG ANALYSIS FOR THIS PROCEEDING?

A. No, it did not. MDU did not include an allowance for cash working capital in its proposed rate base.

Q. IS IT APPROPRIATE TO IGNORE CASH WORKING CAPITAL IN THE CALCULATION OF RATE BASE?

A. No, it is not. To the extent that a utility has a large cash working capital requirement, ignoring that requirement when setting rates creates an earnings shortfall for the utility. On the other hand, if ratepayers rather than investors are providing the utility excess working cash, ignoring cash working capital in the calculation of rate base overstates the utility's revenue requirement and customers end up paying rates that are excessive.

Q. WHAT DO YOU RECOMMEND?

A. This is not the first rate case in which MDU did not present a lead-lag cash working capital analysis. In prior rate cases where MDU failed to present a lead-lag analysis, the Commission Staff presented its own lead-lag analysis. Therefore, I am sponsoring a determination of MDU's cash working capital requirement based on a lead-lag analysis. The results of my lead-lag study are shown in Exhibit___(DEP-1). This schedule shows South Dakota ratepayers, rather than MDU's investors, are providing cash working capital to MDU. Under these circumstances, it is appropriate to reduce rate base to recognize MDU's negative cash working capital requirement since rate base is intended to represent only the utility's investor-supplied capital requirements. Consequently, Ms. Mehlhaff's revenue requirement study includes a $(357,245) rate base allowance for cash working capital.

Q. FROM WHERE WAS THE EXPENSE LEAD DAYS SHOWN IN YOUR LEAD-LAG STUDY TAKEN?

A. MDU was unable to provide a current, detailed analysis of the timing of its receipt of revenue from customers and its payment of expenses to vendors and suppliers. Therefore, it was necessary for me to rely on the revenue and expense lead and lag days that the Commission Staff used in its lead-lag studies in MDU's most recent South Dakota rate cases.[12]

Q. DO YOU HAVE ANY OTHER COMMENTS ABOUT YOUR LEAD-LAG ANALYSIS?

A. Yes, I do. The revenue lag portion of my analysis assumes, in part, that all customers pay their monthly statement on the due date. In that regard, South Dakota Administrative Rules provide that customer payment is due 20 days following the day the monthly statement is rendered. A 20-day payment lag assumption is necessary in this case because MDU was unable to provide me its actual revenue collection lag. The 20-day collection lag assumption favors MDU in that not all customers wait until the due date to pay their bill. There are instances, however, when customer payments extend beyond the past-due date. In those instances, MDU is allowed to impose and collect a late-payment fee. Those fees become part of MDU's revenue. Because my revenue lag does not consider any payments beyond the past-due date, it is appropriate for MDU to retain the

[12] SDPUC Docket Nos. NG02-011 and NG04-004.

related late-payment fee revenues it has collected. For this reason, Ms. Mehlhaff's revenue requirement study does not include an adjustment to increase test period revenues by the amount of the late-payment fees that were collected during the test period, as proposed by MDU. That is, revenues collected through the late-payment fee should not be credited to MDU's revenue requirement.

Also, I was unable to determine the expense lead days associated with MDU's payment of insurance premiums. Therefore, it was necessary for me to exclude insurance expense from my analysis. Because this expense was not considered in my lead-lag analysis, it is appropriate to include MDU's test year average balance of prepaid insurance expense as an addition to rate base and to reduce MDU's injuries and damages reserve from rate base. Ms. Mehlhaff has included these two additional rate base adjustments in her revenue requirement study.

In addition, notice that my lead-lag analysis shown on Exhibit___(DEP-1) includes depreciation and deferred tax expenses at zero expense lead days. It has been my consistent position that non-cash expenses, such as depreciation and deferred taxes, do not create a requirement for cash working capital. In fact, both of these expenses are included in MDU's financial statements as a source of working cash, not a requirement for working cash. However, I understand that the Commission Staff traditionally has included depreciation and deferred taxes in its lead-lag studies for MDU and for other South Dakota utilities using zero expense lead days for each expense. Therefore, I am not challenging the inclusion of these two non-cash expenses in my lead-lag study. My analysis in this case follows the Commission Staff's traditional approach.

Q. PLEASE EXPLAIN YOUR "TAX COLLECTIONS AVAILABLE" SCHEDULE THAT YOU INCLUDE IN EXHIBIT___(DEP-2).

A. This is a cash working capital related issue as well. MDU collects certain taxes from employees (e.g. FICA, FUTA, etc.) and from customers (sales tax). MDU holds the taxes collected from employees and from customers until the time it is required to remit those taxes collected to the taxing authorities. During that holding period, however, MDU has use of those monies to fund its working capital requirements. That is, these tax payments are a source of cash working capital to MDU. As such, they should be credited to MDU's cash working capital requirement via a rate base deduction.

VII. RATE CONSOLIDATION

Q. IN ITS FILING, MDU PROPOSED TO CONSOLIDATE, FOR RATEMAKING AND FINANCIAL REPORTING PURPOSES, ITS BLACK HILLS AND EAST RIVER SERVICE AREAS. WHAT DOES THIS ENTAIL?

A. The Company's proposal requires a revenue requirement determination based on the combined costs incurred in the two service areas. If consolidation is approved, its rate schedules for the two areas will be replaced with a tariff having a single rate schedule for each class of customers in the combined areas. In addition, MDU will no longer have to keep separate financial records for the two operating districts.

The going-forward revenue requirement would reflect a rate base consisting of the combined plant investment, accrued depreciation and other rate base components in the two service territories. Similarly, operating expenses would be the sum of expenses incurred in the now-separate South Dakota rate areas.

Q. WHY DOES THE COMPANY HAVE TWO GAS SERVICE RATE AREAS AT THIS TIME?

A. MDU has provided gas service to customers in the Black Hills area since well before the Commission was granted regulatory authority over gas and electric utilities more than 30 years ago in 1975. In its first rate case filed with the South Dakota Commission, MDU was granted an increase in then-existing gas service rates in 1979.

In the East River area, gas service rates were established in 1993 (Docket NG93-003) when MDU introduced natural gas service into the area extending from Mobridge, south to Pierre and Fort Pierre and to towns along the Eastern side of the Missouri River. In short, MDU has two gas service areas because of the timing of the establishment of the two operations and cost differences in providing service in each area as determined in their most recent rate cases in 2004 and 2005.

Q. WHY IS MDU NOW PROPOSING TO CONSOLIDATE ITS BLACK HILLS AND EAST RIVER GAS OPERATIONS?

A. The Company contends that, while not physically integrated, the two South Dakota systems (the Rate areas) now exhibit similar service costs and that a number of these costs are for shared centralized services provided by the parent company and affiliates. The Company also notes that the South Dakota Tariff already prescribes PGA rates that are based on MDU system-wide gas costs.

Q. WHAT WOULD BE THE EFFECTS OF THE COMPANY'S PROPOSAL ON CUSTOMERS IN THE TWO AREAS?

A. The gas service rates in effect at the time of the filing of this case were established in December 2004 (Black Hills area) and September 2005 (East River area). The effect of the present rate filing would be to increase MDU's combined revenues by about $1.5 million, or 3.3% above its revenues at existing rates. However, because the existing area rates differ, the proposed rates based on combined costs would result in an increase of 6.3% for Black Hills area Residential customers and a 2.8% rate reduction for Residential customers in the East River area. Similar disparities would be experienced by Firm General Service customers (an increase of 3.8% in the Black Hills area and a 14.9% decrease in the East River area) while Large Interruptible customers would experience a 9.8% increase.

Moreover, the present design of the Residential rates in the two areas differ considerably – East River customers now pay a lower Basic Service Charge and a higher Delivery Charge than those customers in the Black Hills area. With consolidation of the rate areas, MDU proposes a single Basic Service Charge that is double the existing Basic Service Charge for East River Residential customers.

Q. SHOULD THE RATE CONSOLIDATION BE APPROVED?

A. The transition from separate rate areas to rates based on consolidated costs raises a number of questions, some challenging the propriety of treating the two areas as a single entity while others identify how the two areas already benefit from being treated as one and how the consolidation would result in additional benefits. On balance, I believe that the consolidation is justified and should be approved.

Q. HOW DID YOU REACH YOUR CONCLUSION?

A. While questioning the propriety of MDU's proposed consolidation plan, I observed that the distribution systems in the Black Hills and East River are not physically integrated and service costs in the two areas are likely to be affected by the timing of their development and their unique physical characteristics. As previously explained, the Black Hills system has existed for more than 38 years (prior to 1975) while development of the East River area only began in 1993 after the expansion into this area and initial rates were approved. Obviously, investments in each system would reflect materials and installation methods available when each was constructed affecting investment costs and related expenses. Differences in the physical characteristics of the service areas (compare the plains of East River with the more rugged terrain of Black Hills) would also affect construction costs and maintenance expenses. Demographic differences and differences in business activities may also contribute to cost of service differences.

On the other hand, I also observed how MDU's gas service rates in the separate areas already reflect in both areas the benefits of many joint activities and considered how greater benefits could be achieved through consolidation. MDU's South Dakota customers in the two areas benefit from the common pricing of services provided from within the corporation to both South Dakota rate areas (and to service areas in other states) and that this practice should result in economies of scale that might not be achievable in a stand-alone service area. Labor costs in the two areas reflect labor rates established in labor contracts negotiated for both areas. Moreover, the same depreciation rate schedules are applied to plant investment in each rate area. In addition, ever since MDU's gas supply system was integrated in 1998, its customers in both areas have paid the same gas supply costs through their PGA charges.[13]

Finally, while there are differences in the customer mix in the two areas, arguably creating differences in business risks, the Company's cost of capital and required

[13] See MDU's November 12, 1998 submittal letter proposing to change its PGA rates to reflect integrated system gas supply system.

rates of return in the two areas have consistently been measured at the same corporate level.

Q. HOW WILL FUTURE REGULATORY ACTIVITIES BE AFFECTED WITH CONSOLIDATION OF THE RATE AREAS?

A. Rate determinations will be simplified and less costly. Rate adjustments will be made with a single rate filing or investigation rather than two. For all of these reasons, I support MDU's proposed consolidation plan.

VIII. CLASS COST STUDY – SPREAD OF THE INCREASE

Q. HAVE YOU REVIEWED MDU'S CLASS COST OF SERVICE STUDY IN THIS PROCEEDING?

A. Yes, I have. MDU's class cost study allocates the Company's South Dakota gas – related costs to the various retail classes (e.g., Residential, Firm General Service, Air Force, Small Interruptible and Large Interruptible.). The fundamental principle underlying all embedded cost allocation studies is that costs are attributed to customer groups based on the cost to serve those groups or on relative benefits received by the groups. Costs examined in an allocation study are either directly assigned or allocated. Rationally allocated costs provide a meaningful basis upon which to derive class revenue targets and can be useful in designing rates within customer classes.

Q. WHAT ARE THE STEPS INVOLVED IN PREPARING A CLASS COST STUDY?

A. Although the presentation may vary depending on the analyst performing the study, most costs of service studies involve the same three-step process: functionalization, classification, and allocation.

As the name implies, functionalization is the process that divides the utility's investments, revenue and expenses into functional cost categories that are descriptive of the functions they perform in rendering service. For a gas utility, the functional cost categories usually consist of production, transmission, distribution and customer service. The Uniform System of Accounts provides the starting point to functionalize the utility's investments and expenses.

Q. WHAT IS THE NEXT STEP IN THE ANALYSIS?

A. The next step is cost classification. In this step, the functionalized costs are classified into one or more cost categories. The cost classifications for a gas utility are class customer demands, average or annual energy usage or through-put, customer-related and sometimes revenue-related.

Q. WHAT IS THE FINAL STEP?

A. The final step is cost allocation. In this step, classified costs are allocated to the various customer groups based on each group's responsibility for the service provided by the utility. Primary allocation factors, which are intended to reflect cost causation, relative usage, or cost responsibility, are used to allocate costs to customer classes. Many of the classified costs are then allocated among the customer groups using the primary cost allocation factors. The remaining costs are allocated to customer groups using secondary allocation factors. The secondary factors are derived from one or more of the primary factors using methods that are consistent with cost causation. For example, after utility plant is allocated, by function, to the various classes using primary allocation factors, property taxes are often allocated to rate classes using the resulting derived secondary allocation factor – net plant in service.

Once all of the investments, revenues, and expenses have been properly functionalized, classified and allocated to the rate classes, earned returns can be calculated for each rate class. Each rate class's earned return is then compared to the utility's overall return earned in the jurisdiction to determine if each class is contributing more or less than its equitable share to the utility's overall rate of return. A class whose earned rate of return is less than the overall return is said to be subsidized by one or more of the other rate classes. The rate class or classes whose rates of return are greater than the overall return are said to be the provider(s) of the subsidy to those classes earning less than the overall rate of return.

Q. WHAT ARE THE RESULTS OF MDU'S CLASS COST STUDY?

A. MDU witness Tamie A. Aberle's class cost study is presented in Statement N of MDU's filing statements. Ms. Aberle's results are summarized in the table below.

MDU Gas – South Dakota Jurisdiction
Class Rates of Return Under Existing Rates
(As Filed)

Service Class	Rate of Return	Indexed Rate of Return
Residential	4.15%	0.75
Firm General Service	8.79%	1.59
Air Force	(9.48)%	(1.71)
Small Interruptible	12.49%	2.26
Large Interruptible	0.31%	0.06
Total South Dakota Gas	5.54%	1.00

The rates of return shown in the table above were calculated before the effects of MDU's proposed rate increase. The indexed rates of return in the far right column in the table measure the relative performance of each rate class to the South Dakota retail system as a whole, in terms of earned returns. The indexed return is the ratio of each class's earned return to the South Dakota system average earned return. An indexed return of less than 1.0 for any class indicates that the class return is less than the system average. The implication is that such a class is being subsidized by other rate classes.

Ms. Aberle's class cost study results indicate that the Residential, Air Force, and Large classes are being subsidized by the Firm General and Small Interruptible rate classes. Note that the indexed return for the Residential class is less than 1.0. Based on these results, Ms. Aberle proposed that residential customers receive a somewhat higher (5.2 percent on a consolidated basis) than the system-wide average percentage increase (3.3 percent) that MDU is requesting in this proceeding. Ms. Aberle's proposed class revenue spread does not move the

Residential class all the way to the state-wide average rate of return, however. The following table summarizes the class increases that Ms. Aberle proposed.

MDU-South Dakota Gas
Company Proposed Spread of Requested Increase
Consolidated Basis

Service Class	Increase	Percent Increase
Residential	$1,390,329	5.2%
Firm General Service	$732	0.0%
Small Interruptible	$(73)	0.0%
Large Interruptible (including Air Force)	$157,367	9.8%
Total South Dakota	$1,548,355	3.3%

Q. ARE YOU IN AGREEMENT WITH THE PROCEDURES THAT MS. ABERLE USED IN HER CLASS COST STUDY?

A. Yes. Because judgment is involved, rarely will you find complete agreement on all aspects of a class cost study. However, I conclude that Ms. Aberle's class cost study presents a fair presentation of each classes cost of service and the resulting rate of return.

Q. BASED ON THESE RESULTS, WHAT DO YOU RECOMMEND REGARDING THE ALLOCATION OF THE RATE INCREASE AMONG THE VARIOUS RATE CLASSES?

A. While I agree with the direction of Ms. Aberle's results, the Commission Staff is recommending a revenue decrease rather than an increase. Therefore, adjustments are necessary. The following table shows my recommended spread among MDU's rate classes of Staff's recommended revenue decrease.

MDU-South Dakota Gas
Peterson Recommendation of Spread of Revenue Decrease
Consolidated Basis[14]

Service Class	Revenue Decrease	Percent Decrease
Residential	$521,459	1.96%
Firm General Service	$849,148	4.57%
Air Force	0	0%
Small Interruptible	$22,645	4.57%
Large Interruptible	0	0
Total South Dakota	$1,393,261	3.05%

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED SPREAD OF THE REVENUE DECREASE?

A. If one were to move each rate class to an equalized rate of return, the result would be significant decreases in some rate classes and significant increases in other rate classes. This is shown in my Exhibit ___(DEP-4), Schedule 2, lines 1-10, specifically at line 5.

Given that the Commission Staff is recommending an overall revenue decrease in this case, it does not seem fair that any class should be subjected to an increase. Instead, for the Air Force and Large Interruptible rate classes, whose present revenues are significantly below cost, I recommend that present rates be

[14] See Exhibit___(DEP-4), Schedule 2.

maintained.[15] The Firm General Service and Small Interruptible rate classes presently have an indexed rate of return that is far above what it should be. Therefore, revenues in those two classes should be decreased by a greater than average percentage. The $1,393,261 revenue decrease that the Commission Staff is recommending represents a 3.05% decrease from present revenues, excluding revenues from the Air Force and Large Interruptible rate classes where I recommend no change. I recommend that the Firm General Service and Small Interruptible rate classes each receive 1.5 times the average percentage revenue decrease (excluding revenues from the Air Force and Large Interruptible rate classes). This results in a 4.57 percent (3.05 multiplied by 1.5) decrease for the Firm General Service and Small Interruptible rate classes and a 1.96% decrease for the Residential rate class. The results of my proposed revenue spread and its impacts on class rates of return are developed in my Exhibit___(DEP-4), Schedule 2, and are summarized in the following table.

MDU-South Dakota Gas
Class Rates of Return Following the Rate Decrease
Peterson Recommendation
Consolidated Basis[16]

Service Class	Rate of Return	Indexed Rate of Return
Residential	5.86%	0.81
Firm General Service	10.65%	1.47
Air Force	(16.98)%	(2.35)
Small Interruptible	18.24%	2.52
Large Interruptible	0.55%	0.08
Total South Dakota	7.23%	1.00

[15] MDU proposes to merge the Air Force load into the Large Interruptible rate class. The Commission Staff is not opposed to this change.
[16] See Exhibit___(DEP-4), Schedule 2.

IX. MARGIN SHARING

Q. HAVE YOU REVIEWED MDU'S PROPOSAL FOR SHARING MARGINS TO BE EARNED ON ITS SALES TO INTERRUPTIBLE CUSTOMERS USING NATURAL GAS FOR GRAIN DRYING OPERATIONS?

A. Yes, I have. The Company proposes to credit all firm gas sales customers with 90 percent of the margins it will earn from its interruptible sales to grain drying operators. The credit would be passed to the firm customers in MDU's annual PGA rate filings where it will be tracked to insure that firm customers receive their full share of the margins, including margins earned on sales through the effective date of rates established in this case.[17] The remaining ten percent of the margins achieved will be retained by the Company as an incentive to increase grain drying sales.

Q. IS THE COMPANY'S MARGIN SHARING PROPOSAL ACCEPTABLE?

A. Yes, it is. Gas sales to grain dryers are unpredictable because it is affected by outside forces beyond both MDU's and grain dryers' ability to control, including the supply of and demand for the grain products and weather conditions. Because of these uncertainties, no sales to these loads are reflected in MDU's rate filing and, in lieu thereof, the Company has proposed the margin sharing arrangement.[18]

Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO RETAIN TEN PERCENT OF THE MARGINS EARNED?

[17] See Proposed PGA Rate 88, Page 6 of 6, Para. 6 – Margin Sharing Mechanism.
[18] See Direct Testimony of Tamie A. Aberle, page 16, lines 3 through 17 and MDU's response to Staff Request No. 4-8 which indicates sales levels ranging from a high of 81,284 dkt for the twelve months ended June 2010 to a low of 9,095 dkt for the TME June 2011. MDU's test year sales to grain dryers were 38,593 dkt .

A. Historically low market prices for natural gas have only recently made it cost effective for grain dryers to switch from other fuels to natural gas. Consequently, the Company has seen new opportunities to capitalize on this situation by encouraging more of this fuel switching. However, acquiring these loads is dependent on the costs involved in attaching the grain dryer to MDU's gas distribution system as well as the fuel price differentials. MDU sees the proposed ten percent retention as an incentive to identify prospective loads and to convince the customer that the fuel switch is both feasible and justified.[19]

Although the need for any such incentive for MDU to act to increase interruptible sales is questionable and the ten percent retention level is necessarily arbitrary, the concept is similar to margin sharing arrangements that have been approved for other South Dakota utilities, notably for application to off-system sales. Notwithstanding my belief that the ten percent retention level is appropriate now, as the concept is first reflected in MDU's tariff, it should be evaluated again in the Company's next rate filing.

X. BASIC SERVICE CHARGE

Q. WHAT CHANGES IS MDU PROPOSING TO BASIC SERVICE CHARGES?

A. Presently, MDU's East River Residential customers pay a Basic Service Charge, regardless of the gas volumes consumed, of $0.15 per day (equivalent to approximately $4.56 per month). Black Hills Residential customers presently pay a $.25 per day Basic Service Charge (equivalent to approximately $7.60 per month). MDU proposes to increase the Basic Service Charge to $0.30 per day

[19] See Direct Testimony of Rita A. Mulkern, pages 17-18.

(approximately $9.13 per month) for all residential customers. For Firm General customers, MDU proposes to increase the Basic Service Charge from $0.35 (Black Hills) and $0.25 (East River) to $0.42.

Q. HOW DOES MS. ABERLE ATTEMPT TO JUSTIFY THESE INCREASES?

A. Ms. Aberle does so by inferring that her proposed Basic Service Charges are cost based. Indeed, on Statement N, Schedule N-1, page 1, MDU calculated a $12.89 customer cost per month for the Residential class. From there, Ms. Aberle states that setting the Basic Service Charge closer to the cost of service provides certain benefits such as minimizing subsidies within rate classes and greater fixed cost recovery when customers reduce consumption.[20]

Q. DO YOU AGREE THAT MDU'S CLASS COST STUDY CORRECTLY QUANTIFIES THE CUSTOMER-RELATED COST OF SERVICE AT $12.89 FOR THE RESIDENTIAL CLASS?

A. No, I do not. The $12.89 per month amount shown in MDU's class cost study reflects all costs in the study that are classified and allocated to the Residential rate class based on customer count. This amount includes certain costs that are classified on a customer basis but are not directly proportional to the number of customers served. However, just because a cost is classified on the basis of customer does not axiomatically justify its inclusion in the determination of the Basic Service Charge. There are certain costs that are classified to the customer component in a class cost study simply because there is no better cost classification method. But, there is no precise nexus between costs classified as customer-related and the costs properly includable in a Basic Service Charge

[20] See Direct Testimony of Tamie A. Aberle, page 14.

determination. Additionally, the $12.89 amount is overstated because it reflects MDU's proposed rate of return which Staff witness Copeland testifies is excessive.

Q. HAVE YOU ANALYZED THE CUSTOMER-RELATED COSTS THAT ARE PROPERLY INCLUDED IN THE BASIC SERVICE CHARGE FOR THE RESIDENTIAL AND FIRM GENERAL SERVICE RATE CLASSES?

A. Yes, I have. My analysis is summarized on Exhibit___(DEP-5). All of the cost data included in my analysis are taken directly from, or are derived from, MDU's class cost study contained in Statement N. My analysis also includes all of MDU's proposed pro forma plant and expense adjustments, even though the Commission Staff is taking exception to many of MDU's proposed adjustments. In my analysis, however, I substituted Staff witness Mr. Copeland's recommended rate of return for MDU's proposed rate of return.

In my analysis, I defined customer-related costs to include MDU's investments and operating expenses necessary to connect and to maintain an account, regardless of usage. My determination includes a return allowance on MDU's net investment in meters and services as well and meter and service-related O&M expenses, related A&G expenses, depreciation, property taxes and income taxes.

The following table compares the results of my customer-related cost analysis to MDU's proposed daily Basic Service Charges.

MDU-South Dakota Gas
Comparison of Daily Basic Service Charges
Consolidated Basis[21]

Service Class	MDU Proposed	Peterson Recommended
Residential	$0.30	$0.28
Firm General Service – Small	$0.42	$0.30
Firm General Service – Large	$1.00	$1.07

Q. ARE YOU RECOMMENDING THAT YOUR COST-BASED BASIC SERVICE CHARGES BE IMPLEMENTED AT THIS TIME?

A. No, I am not. While I believe there is sufficient cost support for charges shown in the table above, other non-cost considerations present at this time dictate that they not be implemented. Increasing MDU's currently effective Basic Service Charges to their cost-based levels could expose small volume residential and small commercial customers to increases in monthly gas bills at a time when the Commission Staff has determined that MDU's rates should be reduced, not increased.

A change in the Basic Service Charge is necessary at this time, however, if rate consolidation between the Black Hills and East River areas is to be accomplished. Therefore, I recommend that the Basic Service Charges between the two service areas be equalized by increasing the Basic Service Charges in the East River area so that they match the existing charges in the Black Hills area. No additional increases in the Basic Service charges are necessary or appropriate at this time.

[21] See Exhibit___(DEP-5).

Instead, the volumetric rates in each rate class should be decreased to yield the remaining class revenue requirements.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.