MASTER FILE

Service Date: May 12, 2005

DEPARTMENT OF PUBLIC SERVICE REGULATION
BRFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority to Increase Rates for Natural Gas Service in its Montana Service Areas	))))	UTILITY DIVISION DOCKET NO. D2004.4.50 ORDER NO. 6580a

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FINAL ORDER

APPEARANCES

FOR THE APPLICANT

John Alke, Hughes, Kellner, Sullivan, and Alke, Attorneys at Law, 406 Fuller Avenue, P. O. Box 1166, Helena, Montana 59624-1166.

FOR THE INTERVENORS

Mary Wright, Staff Attorney, Montana Consumer Counsel, 34 West Sixth Avenue, P.O. Box 201703, Helena, Montana 59620-1703, for the Consumer Counsel.

FOR THE COMMISSION

Dave Burchett, Rate Analyst, Will Rosquist, Rate Analyst, and Martin Jacobson, Staff Attorney, 1701 Prospect Avenue, P.O. Box 202601, Helena, Montana 59620-2601.

FINAL ORDER BEFORE

GREG JERGESON, Chairman
BRAD MOLNAR, Vice-Chairman
DOUG MOOD, Commissioner
ROBERT H. RANEY, Commissioner
THOMAS J. SCHNEIDER, Commissioner, Hearings Examiner

I. INTRODUCTION

1. On April 1, 2004, Montana-Dakota Utilities Co. (MDU) filed with the Montana Public Service Commission (PSC) an application to increase its rates for natural gas service in Montana. MDU requested an increase in annual non-gas revenues of $1,513,048, approximately 1.8% of test year revenues of $83,358,279. If approved, the increase would affect approximately 73,150 Montana natural gas customers. MDU asserted it needs additional revenue to recover increased operating and maintenance expenses associated with higher labor and benefit costs and depreciation expense. MDU stated that in spite of cost control efforts, increases in operating and maintenance expenses have made current rates insufficient to compensate MDU for operating its Montana natural gas distribution system. MDU's last general rate increase in Montana occurred in 2002, in PSC Docket No. D2002.5.59.

2. MDU's proposed rate increase would affect customer classes by the following amounts and percentages:

Table 1

Customer Class	**Amount**	**Percent Increase**
Residential	$969,849	1.9%
Firm General Service	$543,199	1.9%
Small Interruptible	$0	0.0%
Large Interruptible	$0	0.0%
Total	$1,513,048	1.8%

3. On May 21, 2004, Montana Consumer Counsel (MCC) petitioned for intervention. On June 8, 2004, the Commission granted MCC's petition. No other party intervened in the proceeding.

4. During the course of procedures, MDU and MCC reached an agreement regarding depreciation rates, which resulted in a reduction to MDU's initial rate increase request from $1,513,048 to $1,084,052.

5. A public hearing was held in Billings, Montana, on November 17, 2004, before Commissioner Tom Schneider, acting as hearings officer. Six witnesses testified on behalf of

MDU and three witnesses testified for MCC. Four witnesses returned for MDU and testified in rebuttal to the MCC.

6. MDU's post-hearing brief provided a statement of the case and a summary of testimony of its six witnesses. Bruce T. Imsdahl, President of MDU, presented an overview of Montana operations, including the need for a general rate increase. Craig A. Keller, Vice President, Controller and Chief Accounting Officer presented the Company's capital structure and associated capital costs. He documented a weighted cost of capital of 10.038%. The cost of equity capital for MDU's Montana operations was presented by J. Steven Gaske, President of Zinder Companies. Mr. Gaske proposed an allowed return on equity of 11.50%. Paul W. Conley of Towers Perrin described MDU's Supplemental Income Security Plan, or SISP, and discussed the reasonableness of the compensation paid to key MDU employees. Rita A. Mulkern presented MDU's per books cost of service for MDU for test year 2003. Finally Tamie A. Aberle presented an allocated class cost of service study and supported the Company's proposed rate design.

7. MCC's three witnesses were Albert E. Clark, Stephen E. Hill and George L. Donkin. Albert E. Clark presented the overall revenue required advocated by MCC. Mr. Hill argued for a cost of equity capital for MDU of 9.75% and Mr. Donkin reviewed the cost of service studies and proposed alternative rate design.

8. In rebuttal MDU's Mr. Gaske and Mr. Keller offered explanations of why MCC's cost of equity capital was unreasonable. Ms. Mulkern offered an explanation of why Mr. Clark was wrong and Ms. Aberle presented testimony opposing Mr. Donkin's criticisms.

9. On January 14, 2005, MDU and MCC submitted a Stipulation, representing the agreement would fairly and equitably resolve the issues between them and would result in just and reasonable rates.

II. FINDINGS OF FACT, DISCUSSION, AND DECISIONS

A. REVENUE REQUIREMENTS

MDU Prefiled Direct Testimony

Bruce T. Imsdahl

10. Mr. Imsdahl, President of Montana-Dakota Utilities Co., gave a brief opening statement on the overall operations of MDU and its need for a general rate increase. Mr. Imsdahl

stated that the current cost of providing natural gas service to MDU's Montana customers is not adequately reflected in the currently authorized rates.

11. Gas costs, which are passed to customers dollar-for-dollar are not a part of this filing. Gas costs account for approximately 78% of a typical residential bill for gas service. Distribution costs, he said, which are regulated by the PSC include operation and maintenance expenses, depreciation, taxes, and a component for the opportunity to earn a return on investment are typically 22% of a residential bill.

12. Mr. Imsdahl concluded by saying that he believes the proposed rates are just and reasonable and is reflective of the total costs being incurred by MDU in providing natural gas service to its Montana customers.

J. Stephen Gaske

13. Dr. Stephen Gaske, President of Zinder Companies, recommended an overall rate of return of 10.038 %, with an 11.50% return on common equity for the cost of capital for MDU. He argued that because MDU must compete for capital with many other potential projects and investments, it is essential that it have an allowed return that matches returns potentially available from other investments with similar risks. The Discounted Cash Flow (DCF) method, he stated, provides a good measure of the returns required by investors in the financial market. The DCF method requires a market price of common stock to compute the dividend yield component of the DCF analysis. Because MDU is a division of MDU Resources and does not have publicly-traded common stock, a direct market-based DCF analysis of MDU as a stand alone company is not possible. Dr. Gaske said he then selected a group of natural gas distribution companies with publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for MDU's Montana natural gas distribution operations.

14. Dr. Gaske used the risk premium approach because he believes this approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. He said he believes investments in common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income left after bondholders have been paid. In the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinated to the claims of the bondholders. He said he believes this superior standing

provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when bonds mature. Dr. Gaske concluded the risk premium approach estimates the returns investors require from common stocks by utilizing current market information readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

15. In comparing the risk faced by MDU's Montana natural gas distribution operations with the risk faced by the proxy group companies Dr. Gaske found four broad categories of risk that concern investors: 1) business risk, 2) regulatory risk, 3) financial risk, and 4) market risk.

16. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists, according to Dr. Gaske, because forecasts of both demand and costs are inherently uncertain. MDU's gas distribution operation faces some risks that distinguish it from many other distribution companies. MDU's natural gas distribution operations are considerably smaller than the operations of any of the proxy companies and a small fraction of the size of the typical proxy company. The typical proxy company is somewhere between approximately 6 and 42 times the size of MDU's natural gas distribution operations.

17. With its small revenue base, stated Dr. Gaske, MDU is subject to slightly greater risk than a major employer or industry, such as a mining operation or refinery might experience in a downturn that would significantly affect overall employment and income in the areas served.

18. Regulatory risk is closely related to business risk and might be considered just another aspect of business. Dr. Gaske stated that to the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may set the rates at a level that will not allow full cost recovery. Regulation, he said, often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries. Regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the general gas distribution industry. The regulatory climate in Montana, according to Dr. Gaske, is generally viewed as being average among regulatory jurisdictions.

19. Financial risk exists to the extent a company incurred fixed obligations in financing its operations. Dr. Gaske stated that these fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the

effects of business and regulatory risks. MDU filed a common equity ratio of 53.0% which is very close to the mean and median common equity ratios of the proxy companies. This common equity ratio, combined with its bond ratings, suggests average financial risk for MDU.

20. Market risk is associated with the changing value of all investments because of business cycles, inflation and fluctuations in the general cost of capital throughout the country. MDU's degree of market risk is not significantly different from that of the companies in the natural gas distribution comparison group.

21. In conclusion Dr. Gaske said he believed that his analyses indicate that an appropriate rate of return on common equity for MDU's Montana natural gas distribution operations for this filing would be 11.50%. This recommended return reflects his assessment that MDU's overall risks are significantly higher than those of the proxy group.

Craig A. Keller, CPA

22. Craig Keller, MDU Vice President, Controller and Chief Accounting Officer, states that the capital structure and the associated costs serve as the basis for his recommended overall rate of return requested by MDU in this rate filing of 10.038%. The basis for the requested 11.50% return on common equity contained within the overall requested rate of return is supported by the testimony of Dr. Gaske. The balance sheet and income statement developed by Mr. Keller is used by MDU's witnesses in this case.

Paul W. Conley

23. Paul Conley, of Towers Perrin, supplied testimony regarding MDU's Supplemental Employee Retirement Program (SERP) called the Supplemental Income Security Plan (SISP) as part of its total executive compensation program. SISP is designed to attract and retain key employees in a number of positions within MDU and provide equitable retirement benefits for those employees. Participants are officers and senior managers of MDU Resources and Montana-Dakota Utility. These employees have the primary management responsibility for keeping MDU competitive in the industry and maintaining an adequate supply of low-cost energy for its customers.

24. Mr. Conley said that retirement benefits normally provided in the qualified plan are limited by IRS regulations and are not provided in the full amount called for in the qualified plan

design. Supplemental programs like SISP help to restore the retirement benefits to their intended level, and ensure a competitive overall retirement program. The removal of SISP, according to Mr. Conley, would unduly hamper the company from meeting its overall reward objectives. Programs such as SISP, Mr. Conley stated, represent a normal cost of doing business.

25. Towers Perrin considers an organization that is within plus or minus 10% of the market 50th percentile to be within the competitive range. Because MDU's program elements fall within plus or minus 5% of the market 50th percentile, Towers Perrin found the overall program to be competitive and appropriate. Removal of any of these elements would represent a competitive shortfall in MDU's ability to attract and retain qualified executives. Mr. Conley concludes that SISP is an important element for a balanced and competitive compensation package for executive employees who tend to be experienced employees who consider retirement benefits an important part of a total compensation package.

Rita A. Mulkern

26. Rita Mulkern, the Regulatory Analysis Manager for MDU, presented MDU's per books cost of service for MDU's 2003 test year along with a pro forma cost of service reflecting known and measurable changes that will have occurred to that cost of service by year end 2004.

27. Montana gas operations had a return on rate base of 9.391% for the twelve months ended December 31, 2003. Ms. Mulkern stated that all adjustments were calculated on either a Montana specific basis or on a total company basis and allocated to Montana.

28. Ms. Mulkern said that MDU utilizes a jurisdictional accounting system that directly assigns and/or allocates every item of revenue, expense, and rate base to the jurisdiction 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 PSC proceedings and are based on a principle of assigning and/or allocating costs to the cost causer.

29. Ms. Mulkern said the pro forma adjustments to operating revenue, expenses and rate base were based on known and measurable changes occurring by December 31, 2004, and conforms to past PSC practices outlined in Rule 38-5-175 ARM. Ms. Mulkern said that, in her opinion, all of the adjustments are reasonably certain to occur and can be measured with reasonable accuracy meeting the criteria of known and measurable.

MCC Prefiled Testimony

Stephen G. Hill

30. Mr. Stephen Hill, MCC expert witness, broke his testimony into four sections. First, he discussed the cost of capital standard as a measure of the return to be allowed for regulated industries, and he reviewed the current economic environment in which the equity return estimate is made. Second, he looked at MDU's actual capital structure in comparison to capital structures employed by the natural gas industry. Third, he evaluated the cost of equity capital for similar-risk operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fourth, he discussed the cost of capital testimony of Company witness, Dr. Stephen Gaske, underscoring the shortcomings he sees contained therein.

31. Mr. Hill's testimony presented a cost of capital analysis for gas distribution operations in Montana. He estimated that the equity capital cost of a utility similar in risk to MDU to be in the range of 9.25% to 9.75%. Within that range, Mr. Hill said a reasonable point of estimate of the current cost of equity capital for MDU would be at the upper end of that range, or 9.75%. He said that data confirm that his 9.25% to 9.75% equity return range for the gas distribution operations under consideration is conservative.

32. Mr. Hill stated that MDU witness Gaske based his recommendations on the results of three DCF analyses, which he checks with a risk premium analysis and a comparable earnings analysis. Mr. Hill said Dr. Gaske's DCF methodologies are flawed and produce results which are overstated due to a heavy reliance on projected earnings growth rates.

33. According to Mr. Hill, even though Dr. Gaske's DCF produces overstated results, he believes they are more reasonable results than his Risk Premium analysis, which he thinks significantly overstates MDU's cost of equity capital. He reasoned that it is based on very long-term return data not necessarily representative of current risk/return relationships and it attempts to measure a return appropriate for all stocks, not utility stocks, which are considerably less risky than the broad market measure and that it relies on historical return data for small companies that are of questionable origin and do not apply to utilities.

34. Mr. Hill stated that Dr. Gaske's third methodology, which he terms his "Alternative Equity Investment Analysis," is simply a comparable earnings analysis that uses the earned

returns of unregulated industrial firms as a gauge of the return for MDU. Mr. Hill said that this comparison is inappropriate because those firms are not of comparable risk to MDU.

Albert E. Clark

35. The purpose of Mr. Clark's testimony was to present conclusions and recommendations to the PSC regarding MDU's test year revenue requirements. He addressed all revenue requirement issues raised by this application except the appropriate capital structure and cost of capital which were addressed by Mr. Hill.

36. MDU has proposed to use a historical test year ended December 31. 2003. Mr. Clark accepted the use of this historical period, as adjusted, for the test year in this case. He stated MDU has made many adjustments to the historical test year under the guise of being "known and measurable." In reality, according to Mr. Clark, MDU has made substantial post-test year adjustments that are based solely on the 2004 operating budget and pro form the historical test year into a budgeted 2004 test year. He said a budget is not an appropriate basis to be used to determine known and measurable changes as contemplated by the PSC.

37. Mr. Clark stated that MDU's requested annual revenue increase is excessive and should not be allowed by the PSC. He concluded that the PSC should order a revenue decrease of at least $248,245. Direct testimony of MDU's witness Bruce T. Imsdahl was that the primary reason for the requested increase is increased operating expenses driven largely by increases in labor, benefit costs, and depreciation expense. Mr. Clark states that the labor costs and the benefit costs, among other costs, are overstated in MDU's filing and depreciation expense (i.e. the proposed new depreciation rates) are absolutely unsupported anywhere.

38. Revised depreciation expenses were provided by MDU. That calculation produces a requested revenue increase of $1,084,052, or a reduction of $428,610. Mr. Clark said that, since MDU totally failed to offer any support for the originally requested overall increase in depreciation rates, if the parties are unable to reach a stipulation or the PSC opts not to approve the agreed upon rates, he recommends that the PSC specifically approve the existing depreciation rates.

39. The first adjustment Mr. Clark proposed is to eliminate the cost of gas from the operation and maintenance expenses and from sales revenues. That results in the removal of

$64,084,689 from operation and maintenance expenses and $64,084,500 from sales revenues. The very slight difference between these two amounts is *de minimus*.

40. Mr. Clark's next adjustment was to bring the net margin from merchandising operation "above the line" so that there is no chance that Montana ratepayers are subsidizing this non-utility, unregulated operation. The reported number for MDU is $1,582,258 for calendar year 2003. Mr. Clark allocated a portion of this amount to the gas utility and then allocated a portion of the gas utility amount to Montana. His adjustment increases other operating revenue by $81,339.

41. Mr. Clark proposed to reduce test year labor expense by $89,110. The basis for this adjustment is to use a percentage increase of 5.36% in lieu of the 6.82% used by MDU to calculate what is essentially a 2004 labor expense.

42. Mr. Clark proposed an adjustment to test year payroll related taxes. MDU proposed to measure test year payroll related taxes as a percentage of per books gas utility to per books gas utility payroll expense multiplied by the pro forma Montana payroll expense. The 2003 Montana gas operation payroll taxes were compared to the 2003 Montana payroll expense. The resulting ratio of 7.2052%, stated Mr. Clark, is applied to his proposed pro forma test year labor expense and compared to the pro forma payroll taxes included in MDU's filing. His adjustment is ($3,574).

43. MDU proposed to include $257,163 in test year expenses for the cost of the Supplemental Income Security Plan ("SISP"). Mr. Clark proposed to disallow this adjustment. The SISP is a plan to increase the retirement benefits of selected officers, directors and senior executives of MDU Resources and its subsidiaries and affiliates. MDU indicated out of a total of 1,063 employees, only 53 are SISP participants. Mr. Clark said, as a matter of public policy, it is not equitable to ask ratepayers to bear the additional costs associated with the provision of retirement benefits that exceed ERISA limitations.

44. Mr. Clark proposed to reduce MDU's pro forma insurance expense by $66,556 to remove the premiums associated with the Directors' and Officers' Liability insurance policies. The sole purpose of this request by MDU is to protect stockholders against malfeasance by MDU's directors and officers. Ratepayers do not benefit from this coverage in any way according to Mr. Clark.

45. Next Mr. Clark proposed to reduce MDU's consumption of utility services. This consumption is used by MDU to move gas, light its facilities, heat and cool its facilities and perhaps other uses as well. He proposed a reduction in pro forma operation and maintenance expenses by $2,574.

46. A reduction in MDU's claimed pro forma uncollectible expense by $39,900 was proposed by Mr. Clark. He proposed to remove years 2001 and 2002 because they are far out of line with normal uncollectible expenses, one too high and one too low. He said years 1999, 2000 and 2003 appear to be more representative.

47. Next Mr. Clark proposed to increase late payment revenues by $11,145. Mr. Clark states that, for twelve months ended May 2004, the actual late payment revenues are $50,977 for Montana gas operations. MDU proposed to use $38,932 which is actual recovery during 2003. He said the more recent experience should be used for ratemaking purposes.

48. The last adjustment to the pro forma income statement was to synchronize the interest expense with the capital structure and the rate base plus non-base construction work in progress. The impact of that adjustment was to increase current income tax expense by $15,077.

49. Mr. Clark concluded that MDU's requested revenue increase of $1,512,662 (reduced to $1,084,052 after taking into account the agreement relative to depreciation rates) is excessive and he recommended that the PSC reject MDU's request for that level of increase. He further concluded that MDU is actually over-recovering $248,245 from its Montana gas operations on a pro forma basis. He recommended that the PSC order a revenue decrease of $248,245. Mr. Clark stated that his conclusions and recommendations are based on his analysis of MDU's filing, supporting data and information, and the use of cost of capital and capital structure recommendations of MCC witness Mr. Stephen G. Hill.

<u>MDU Rebuttal Testimony</u>

50. In rebuttal MDU provided four witnesses to the MCC. Dr. Gaske and Mr. Keller explained why MCC witness Hill's proposed capital structure and cost of equity capital were unreasonable. Ms. Mulkern addressed issues raised by MCC witness Clark and explained why she felt many of Mr. Clark's adjustments to MDU's revenue requirements were not only unreasonable but in some instances simply wrong. Finally, Ms. Aberle disagreed with MCC

witness Donkin's criticisms of MDU's class cost of service studies and proposed rate design and explained why she felt they were misplaced.

Stipulation

51. The Stipulation between MDU and MCC stated that for purposes of settling the contested issues in this proceeding, a fair and equitable resolution of the issues that would result in the establishment of just and reasonable rates would be structured as follows. First, MDU should be authorized to increase the Basic Service Charges contained in its rates 60 and 70 as follows: Rate 60, by 10 cents per month; Rate 70, small meter, by 40 cents per month; and Rate 70, large meter, by 80 cents per month. These rate changes are estimated to generate an additional $124,625 in annual revenue.

52. Second, the stipulated rate change should be implemented immediately, if possible for services rendered on and after February 1, 2005. This provision was an essential component of the Stipulation for MDU as no interim rate relief of any kind was authorized in this docket.

53. Third, after the completion of contested case proceedings in this docket, the Commission should, in its discretion, issue a final order approving, adopting, and implementing the terms of this Stipulation.

54. After careful review the Commission finds that the annual revenue increase proposed in the Stipulation to be just and reasonable.

B. COST OF SERVICE AND RATE DESIGN

Introduction

55. As noted above in Table 1, MDU initially proposed class revenue increases of $969,849 and $543,199 for the residential and firm general service rate classes, respectively. MDU also proposed various changes to its operating rules, including a distribution delivery stabilization mechanism to correct for over/under collections of distribution delivery charge revenues due to weather variation.

56. MDU's sales tariffs are Rate 60 (residential), Rate 70 (firm general service), Rate 71 (small interruptible) and Rate 85 (large interruptible). Transportation tariffs include Rate 81 (small interruptible) and Rate 82 (large interruptible). Other tariffs include Rate 72 (optional seasonal general service), Rate 80 (interruptible electric generation transportation service), Rate

93 (special gas service), Rate 100 (conditions for service), Rates 119 and 120 (line extension policies), Rate 88 (gas cost tracking procedure) and Rate 89 (universal system benefits charge).

57. MDU's last general natural gas rate case occurred in 2002, Docket No. D2002.5.59. In that case, MDU requested an increase in annual revenues of $3,642,269. MDU and MCC, the only intervener, stipulated to an annual revenue increase of $2,393,517, approximately 4.26%. The stipulation increased residential class revenues 4.45%, firm general service class revenues 3.85% and small interruptible class revenues 8.43%. The stipulated rate design increased the residential Basic Service Charge from $5.00 per month to $6.25 per month. The firm general service Basic Service Charges increased from $8.00 per month to $10.00 per month for customers with meters rated under 500 cubic feet per hour, and from $17.00 per month to $21.25 per month for customers with meters rated 500 cubic feet per hour or more. The Commission approved the stipulation, finding its rates fair, just and reasonable.

58. MDU's next most recent general rate case, before Docket D2002.5.59, was Docket D95.7.90. MCC was the only intervener to testify on cost of service and rate design issues. The different methodological approaches for estimating non-gas costs that were debated by MDU and MCC in Docket D95.7.90 are virtually identical to the issues debated in this case, as discussed below.

59. Although Commission rules require applications for rate increases to include a marginal cost of service analysis (ARM 38.5.176), MDU's April 2004 application relied on an embedded cost study. MDU requested a waiver of ARM 38.5.176, asserting that a marginal cost of service study was not relevant to its application because its distribution system is static and, therefore, an embedded cost of service study provides a more appropriate measure of costs on a class of service basis. On May 6, 2004, the Commission denied MDU's request for a waiver of ARM 38.5.176. MDU submitted its marginal cost of service analysis on May 26, 2004.

60. ARM 38.5.176 describes the basic marginal cost model the Commission uses to develop and organize cost of service testimony. That model is summarized in Table 2. Costs are organized first by functions that identify sources of marginal costs, such as production (costs to ensure sufficient gas supplies), distribution and customer costs. Storage and transmission costs are related to the gas supply (production) function. After separating costs into functions, costs within each function are classified according to services provided to customers, such as the capacity to meet demand (demand-related), the flow of natural gas (energy-related) and access to

the distribution system (customer-related). Classified costs are multiplied by the units of each service provided (annual dkt, peak day demand, number of customers) in order to allocate those costs to various customer classes. Total marginal costs equal the sum of all the allocated costs. Because total marginal costs rarely equal the approved revenue requirement, a final step reconciles total marginal costs and the revenue requirement. A uniform percent adjustment is the reconciliation method used most often, although there are other methods. If unacceptable rate changes result, the reconciled revenue increases may be moderated on public policy grounds. Prices must ultimately be set to recover the allowed revenue requirement.

Table 2

Gas Cost of Service Model (ARM 38.5.176)

Cost Function (1)	**Cost Classification (2)**	**Cost Allocation (3)**	**Reconcile and Moderate (4)**	**Rate Design (5)**
Gas production, storage and transmission	Energy, Demand	Annual throughput, Peak day	Uniform percent or other – e.g., market based	$/dkt
Non-gas distribution	Energy, Demand	Annual throughput, Peak day		
Non-gas customer	Customer	Customer classes		$/month/ customer

MDU Testimony on Cost of Service

MDU's Embedded Cost Study

61. Although the Commission has preferred to use marginal costs to set rates, both MDU witness, Tamie Aberle, and MCC witness, George Donkin, focused heavily on embedded costs. Therefore, the Commission briefly summarizes the respective embedded cost positions of the parties.

62. MDU used its embedded cost of service analysis as a guide for allocating total revenue requirements among customers and for setting rate components for each customer class. The goal of Ms. Aberle's rate design proposals was to move each class's individual rate of return closer to the overall rate of return, based on the results of the embedded cost of service analysis. Ms. Aberle's embedded cost of service study indicated that MDU's test year rate of return, adjusted for known and measurable changes, was 6.695%. The study also indicated that the

small and large interruptible customer classes contribute significantly more to the overall return than the residential and firm general service customers. For this reason, Ms. Aberle allocated responsibility for recovering the proposed revenue increase entirely to the residential and firm general service customer classes. Table 3 shows the results of Ms. Aberle's embedded cost of service study, based on information contained in Statement L, Schedule L-1 of MDU's application.

Table 3

MDU's Embedded Cost Model

Cost function	Classification	Allocation		Per unit cost
Distribution $5,367,678	Commodity (energy) $1,620,733	Residential	$905,550	$0.146/dkt
		Firm General Service	$577,253	$0.162/dkt
		Small Interruptible	$68,307	$0.069/dkt
		Large Interruptible	$69,623	$0.017/dkt
	Capacity (demand) $3,746,945	Residential	$2,145,094	$0.347/dkt
		Firm General Service	$1,227,590	$0.345/dkt
		Small Interruptible	$103,224	$0.104/dkt
		Large Interruptible	$271,037	$0.068/dkt
Customer $15,755,918	Customer	Residential	$11,646,923	$14.979/cust/mo
		Firm General Service	$3,851,144	$40.333/cust/mo
		Small Interruptible	$177,913	$361.612/cust/mo
		Large Interruptible	$79,938	$1,332.300/cust/mo
Total (non-gas) $21,123,596				

63. Table 4 shows the total class revenue requirements that resulted from Ms. Aberle's embedded cost study, compared to current revenues.

Table 4

Calculated Embedded Costs vs. Current Revenues

Customer Class	Non-gas embedded costs	Gas costs	Total embedded cost	Pro forma 2004 revenue	Percent difference
Residential	$14,697,567	$40,414,231	$55,111,798	$52,329,434	-5.32%
Firm Gen. Service	$5,655,987	$23,217,561	$28,873,548	$29,276,679	1.40%
Small Interruptible	$349,444	$452,897	$802,341	$1,214,691	51.39%
Large Interruptible	$420,598	0	$420,598	$537,475	27.79%
Total	$21,123,596	$64,084,689	$85,208,285	$83,358,279	2.22%

64. Table 5 shows the rates of return for individual customer classes based on test year data, along with the rates of return that would result from Ms. Aberle's proposed rate adjustments. This information was provided in Statement M of MDU's application.

Table 5

Accounting-based Rate of Return Comparison

Customer class	Test year return	Revenue increase	Proposed return
Residential	1.40%	$969,986	4.69%
Firm General Service	13.61%	$542,676	17.52%
Small Interruptible	62.38%	0	62.38%
Large Interruptible	21.95%	0	21.95%

MDU's Marginal Cost Study

65. On May 26, 2004, Ms. Aberle submitted supplemental testimony presenting the results of a marginal cost of service study. Ms. Aberle stated that the costing methodology she used was the same methodology used in previous marginal cost studies filed by MDU.

66. Ms. Aberle's cost study included three cost components (functions): 1) marginal gas costs, 2) marginal distribution demand costs and 3) marginal customer costs. She stated that marginal gas costs reflect the long-run cost of gas, including pipeline-related charges. She used Statement G, p. 3 of MDU's application as the source of her marginal gas costs. Statement G showed per books test year gas supply expenses and a pro forma adjustment to test year expenses. According to Statement G, the cost of gas is $6.483 per dkt for residential and firm general service customers and $5.434 per dkt for interruptible customers. Ms. Aberle adjusted these costs upwards to account for distribution losses. Her total marginal cost of gas supply, in 2004 dollars, is $6.53 per dkt for firm sales customers and $5.473 per dkt for interruptible sales customers. She emphasized that gas costs are recovered in commodity rates that are adjusted monthly according to a gas cost tracking adjustment mechanism and that MDU did not request changes to gas supply rates as part of this proceeding.

67. Ms. Aberle classified marginal distribution costs as either capacity (demand)-related, or customer-related. She determined that the marginal demand-related distribution cost is $10.65 per peak day dkt based on the cost of incremental investments in distribution mains and related facilities required to provide an additional dkt of distribution capacity on a peak day. She assembled actual and projected investments related to distribution projects designed to increase

the overall capacity of the system for a 10 year period, 1999 through 2008. The sum of investments for the period, restated in 2006 dollars, divided by the total incremental capacity provided by the investments yields $52.33 per peak day dkt for incremental peak day distribution capacity. Ms. Aberle increased this cost to include an allocation of general and common plant and then applied a nominal carrying charge of 12.34% to derive an annual, levelized cost of $8.08 per peak day dkt. She then adjusted this cost to reflect demand-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and working capital. The calculations were provided in her Exhibit TAA-3, pages 4 and 5.

68. Ms. Aberle allocated incremental demand-related distribution costs to residential and firm general service customer classes based on their respective shares of coincident peak day demand. According to an MDU data response (DR PSC-031), the coincident peak day demand is not a weather normalized demand, but is based on the actual peak during the test year. For the small and large interruptible customer classes, Ms. Aberle restated the incremental demand-related distribution cost as a cost per dkt of $0.029 by assuming a 100% load factor for these customers. In the data response (Id), she said that this assumption recognized that interruptible customers do not contribute to the peak day demand costs, but they do place a demand on the system. The resulting cost was allocated to these customers based on annual throughput.

69. Ms. Aberle's calculation of incremental customer-related distribution costs is similar to her calculation of demand-related costs. First, for each customer class she assembled current costs for the capital equipment necessary to connect a new customer to the system: a main extension, service line, meter and regulator. She restated these costs in 2006 dollars. Each of these costs for each customer class was increased to include a share of general and common plant costs and annualized. Then she added customer-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and a working capital component. Her customer-related marginal distribution costs are shown in Table 6. The calculations were provided in her Exhibit TAA-3, pages 6 – 10.

70. Ms. Aberle stated that the O&M expenses, A&G expenses, taxes other than income taxes and working capital amounts that were added to the demand- and customer-related marginal distribution costs reflect a five-year average of embedded costs for the period from 1999 through 2003, restated in January 2006 dollars.

Table 6

MDU's Marginal Customer-related Cost Calculations

	Residential	Firm General	Sm. Interrup.	Lg Interrupt.
Capital investment	$1,016.32	$2,377.89	$7,112.82	$22,478.93
General and Common	$255.50	$597.80	$1,788.16	$5,651.20
Total incremental investment	$1,271.82	$2,975.69	$8,900.98	$28,130.13
Annualized cost	$161.23	$375.44	$1,116.34	$3,538.29
O&M, A&G, Taxes, Working Capital	$144.47	$334.90	$1,024.16	$8,572.06
Total annual incremental customer cost	$305.70	$710.34	$2,140.50	$12,152.73
Total cost per month	$25.48	$59.20	$178.38	$1,012.73

71. The total annual marginal cost revenues for the Montana gas operations are $90,519,939, according the results of Ms. Aberle's study. She calculated a uniform adjustment factor to reconcile the total marginal cost revenues with MDU's proposed total revenue requirement in this case, which, according to Ms. Aberle's worksheets, is $85,208,290. She applied the adjustment factor to the individual class marginal costs to establish reconciled marginal cost revenues by rate class. Table 7 compares class revenues at current rates with Ms. Aberle's marginal cost revenues.

Table 7

MDU's Marginal Cost-based Class Revenue Compariosn

Customer class	Current revenues	Reconciled marginal cost revenues	difference	percent differ-ence
Residential	$52,561,881	$57,141,151	$4,579,270	8.71%
Firm General Service	$29,369,158	$27,432,729	-$1,936,429	-6.59%
Small Interruptible	$1,220,178	$529,836	-$690,342	-56.58%
Large Interruptible	$544,410	$104,574	-$439,836	-80.79%
Total	$83,695,627	$85,208,290	$1,512,663	1.81%

72. Ms. Aberle stated that both the embedded cost of service study and the marginal cost of service study indicated that more than MDU's requested revenue increase of $1,513,048 should be allocated to the residential customer class and other customer classes' rates should be decreased.

MDU's Proposed Rate Design

73. In order to recover MDU's requested revenue increase, Ms. Aberle proposed increasing the monthly Basic Service Charges for the residential and firm general service customer classes. Specifically, she proposed a residential Basic Service Charge of $0.23 per day, which is roughly equivalent to a monthly charge of $6.99 and an increase of $0.74 per month from the current rate. She proposed a firm general service Basic Service Charge of $0.40 per day for customers with meters rated less than 500 cubic feet per hour and $0.80 per day for customers with meters rated 500 cubic feet per hour or more. These daily charges are roughly equivalent to $12.16 per month and $24.32 per month, respectively, an increase of $2.16 per month for customers with meters rated less that 500 cubic feet per hour and an increase of $3.07 per month for customers with meters rated 500 cubic feet per hour or greater.

74. Ms. Aberle proposed recovering the rest of the revenue increase, after accounting for revenues from the higher Basic Service Charges, from distribution delivery charges. For residential customers, the distribution delivery rate would increase from the current $1.14 per dkt to $1.203 per dkt. For firm general service customers the distribution delivery rate would increase from $1.367 per dkt to $1.456 per dkt.

75. For an average residential customer using 110 dkt per year, Ms. Aberle's proposed rate adjustments would result in an annul bill increase of $15.82, or an average of $1.32 per month. An average firm general service customer with a meter rated less than 500 cubic feet per hour would see an annual bill increase of $52.62. An average firm general service customer with a meter rated at 500 cubic feet per hour or greater would see an annual bill increase of $116.93. Attachment A to this order illustrates MDU's proposed rate design and compares: 1) MDU's current rate design, 2) MCC's proposed rate design, and 3) the stipulated rate design approved by the Commission.

76. Ms. Aberle also proposed a Distribution Delivery Stabilization Mechanism (DDSM) as a way to adjust customer bills to reflect normal weather. The DDSM would correct for over/under collection of distribution delivery charge revenues due to weather variation during the heating season (Nov. 1 through Mar. 31). She stated that a DDSM would be determined for each rate class and expressed as a rate per dkt. Monthly bills beginning in May of each year would be

adjusted to recover/refund any under/over collection of distribution delivery revenue in the prior heating season.

Montana Consumer Counsel Testimony

77. George Donkin testified for MCC on cost of service and rate design issues. He stated that, in general, gas utility rates should be structured and designed to promote multiple objectives: 1) conservation of energy supplied by gas utilities, 2) economically efficient use of facilities and resources, 3) equity in rates charged to customers, 4) revenue and earnings stability, i.e., utilities should have a reasonable opportunity to recover allowed costs of service, 5) adequate incentives to control costs, 6) rate continuity, i.e., moderate rate changes are preferred to dramatic changes, and 7) understandability and customer acceptance.

78. Mr. Donkin acknowledged that several of these objectives are often in conflict. Lower monthly customer charges and higher commodity rates might better promote conservation and economically efficient consumption, but might also subject the utility to less stable revenue and earnings. Higher monthly customer charges would stabilize utility revenues, but are often unacceptable to customers and diminish the utility's incentives to control costs. According to Mr. Donkin, regulators normally seek a reasonable balance among the various objectives.

79. According to Mr. Donkin, basing gas utility rates on cost of service sends customers the right price signals and leads to efficient allocation of natural gas resources, but there is not a widely accepted method for preparing cost of service studies. Methods vary among gas utilities and regulatory jurisdictions, and evolve as conditions in the industry change over time. Most methods, according to Mr. Donkin, have some common traits, such as distinguishing between variable costs and fixed costs. He said variable costs are almost always allocated among customers on the basis of their respective annual usage. Fixed costs, which mostly relate to the capacity to deliver gas, can be allocated in a number of different ways, he said. Common factors used to allocate fixed costs are: 1) peak period or peak day usage levels, 2) seasonal usage levels, 3) annual usage levels, and 4) number of customers. Often a combination of the above factors is used.

80. Mr. Donkin described marginal cost of service as the cost of providing one more or one less unit of natural gas, either on a peak day or on an annual basis. Marginal costs vary according to the time frame being considered. Short-run marginal costs reflect the cost of

producing an incremental amount of service holding constant elements of the current physical system such as distribution plant and contracts with pipeline suppliers. The costs of these elements are often fixed in the short-run and, therefore, are not included in short-run marginal costs.

81. Long-run marginal costs do not consist of fixed costs because all inputs to production and delivery are variable in the long run. According to Mr. Donkin, utility rates should not reflect long-run marginal costs since it would take many years to restructure gas supply arrangements and reconstruct physical plant in order to minimize costs in response to small changes in output. He said gas supply arrangements and physical plant are largely fixed and are difficult to change in response to changes in demand, so utility rates usually reflect a form of intermediate-run marginal costs, which include costs associated with existing capacity. Exhibit MCC 3, p. 6.

82. Mr. Donkin explained that embedded cost of service reflects a calculation of a gas utility's historic costs, including costs used to support the allowed revenue requirement. Embedded costs are allocated to customer classes based on historic cost responsibility. He asserted that gas utility service is largely the provision of joint products and embedded cost of service studies attempt to allocate joint costs among rate classes. He said most natural gas utilities and regulatory commissions use embedded cost studies in the ratemaking process, while marginal costs receive more attention when there is a large difference between marginal and embedded costs, as occurred in the early 1980s when market prices of natural gas supplies greatly exceeded the price of regulated gas supplies. Today there is little difference between the marginal and embedded cost of gas supply and short- and intermediate-run non-gas marginal costs are far below embedded costs. As a result, he does not believe basing cost allocation and rate design on short-run marginal costs would promote economically efficient gas consumption decisions or equity in the recovery of non-gas costs. Exhibit MCC 3, p. 8.

Marginal Cost of Service

83. Mr. Donkin did not provide an independent marginal cost of service study. However, he testified that MDU's study did not reflect traditional marginal cost analysis and should not be used to evaluate the reasonableness of MDU's non-gas class revenues and rate design proposals. According to Mr. Donkin, traditional gas utility marginal cost analyses focus on the change in

total costs of increasing gas sendout by incremental amounts. Incremental output could be related to increased consumption by existing customers or from new customers. He said MDU, which experiences very little customer growth, should focus on the marginal cost of peak- and off-peak distribution capacity and argued that Ms. Aberle's study focused on marginal customer costs and provided little information about how MDU's non-gas costs increase or decrease as customers increase or decrease their consumption of natural gas. He maintained that 96.9% of Ms. Aberle's total non-gas marginal costs were classified as customer costs and 97.7% of residential class non-gas marginal costs were classified as customer costs. He said these results lead to the implausible conclusion that off-peak conservation or an increase in off-peak consumption would have zero impact on MDU's total non-gas cost of service. He also concluded that under Ms. Aberle's cost study adding new customers to MDU's system adds more costs than revenues. He believes Ms. Aberle's cost study overestimated the actual cost of adding a new residential customer and, therefore, her marginal cost study has no value for evaluating the reasonableness of non-gas revenue responsibility on the MDU system.

84. Mr. Donkin asserted that marginal gas costs are not relevant to this proceeding because MDU recovers gas supply costs through a tracker. Nonetheless, he testified that MDU's marginal gas cost consists of the cost of acquiring gas supply from gas producers or marketers, including variable transport costs. He said MDU's marginal gas cost should not include demand or reservation charges paid to its pipeline supplier, Williston Basin Interstate Pipeline (WBIP), since MDU cannot avoid paying these charges under long-term service agreements. In other words, pipeline demand and reservation charges are fixed in the short-term. And, he said, even in the long-term MDU has a limited ability to avoid these charges because MDU represents such a large percentage of WBIP's firm demand. Any reduction in MDU's firm contract capacity would likely result in a corresponding increase in the charges MDU pays WBIP. Exhibit MCC 3, p. 10. While noting that MDU's marginal gas cost fluctuates widely over time, he estimated that the summer 2004 cost ranged between $5.50 and $6.00 per dkt. Id., p. 11.

<u>Embedded Cost of Service</u>

85. Mr. Donkin also disagreed with MDU's embedded cost study. He said Ms. Aberle's study allocated most non-gas costs based on the number of customers and peak period volumes. Statement L, Schedule L-1 of the Company's application showed that Ms. Aberle's embedded

cost study classified 74.6% of total non-gas costs as customer related, 17.7% as demand related and 7.7% energy related. According to Mr. Donkin, Ms. Aberle's method assigns an excessive amount of non-gas costs to small volume customers in the firm rate classes, and too little to interruptible customers.

86. According to Mr. Donkin, MDU classified 30 percent of distribution mains costs as customer-related and 70 percent demand-related, but none of these costs should be classified as customer-related. Distribution mains are part of the integrated delivery system that provides energy supply throughout the year and during peak periods. He maintained that the load, not the number of customers, drives the utility's investment in distribution plant. He recommended classifying 50 percent of distribution mains cost as demand-related and allocating those costs to customer classes based on coincident peak day demands at distribution. He would classify the other 50 percent of distribution mains costs as energy-related and allocate them to customer classes based on annual throughput at distribution. He reasoned that even if customer demand did not vary over the course of a year, the capacity of the distribution system would still have to be designed to meet a peak-day demand of 33,130 dkt. Therefore, some distribution costs are related to average annual usage and some are related to peak period deliveries, which, he said, supports classifying 50 percent of these costs as energy-related. Additionally, he said, many of the costs of gas distribution mains do not vary according to pipe capacity, for example excavation costs, rights-of-way costs, inspection costs, surveying costs and the costs of replacing sidewalks and roads, so total costs do not increase by a one-to-one ratio as peak demand increases.

87. Mr. Donkin disagreed with Ms. Aberle that 100 percent of distribution service line costs should be classified as customer-related since this approach does not recognize that the primary function of a service line is to move gas volumes from the distribution main to the point of consumption. He recommended classifying 50 percent of the total investment in service lines as customer-related and 50 percent demand-related. He recommended allocating the demand-related portion on the basis of coincident peak day demand at distribution.

88. Mr. Donkin recommended allocating administrative and general expenses 50 percent on the basis of coincident peak day demand and 50 percent on the basis of total throughput. He also used this method to allocate several other components of MDU's total embedded costs, including investments in general plant and common plant, other taxes and gas in underground

storage component of working capital. He said he allocated uncollectible accounts and sales expenses on the basis of class revenues, rather than the number of customers in each rate class. The rates of return for each customer class that result from Mr. Donkin's recommendations compared to MDU's embedded cost study are provided in Table 8.

Table 8

Accounting Rates of Return: MCC vs. MDU

	MCC	**MDU**
Overall	6.695%	6.695%
Residential	8.650%	1.401%
Firm General Service	11.015%	13.607%
Small Interruptible	62.381%	13.816%
Large Interruptible	-17.769%	21.946%

89. According to Mr. Donkin, with appropriate changes Ms. Aberle's embedded cost of service study would show that existing rates of return for MDU's customer classes are reasonably in line with each other, except for the Large Interruptible class, which is producing a significant negative rate of return at current rate levels. Accordingly, he asserted that MDU's proposal to increase non-gas revenue while holding constant the non-gas revenue responsibility of its interruptible customer classes is unjust, unreasonable and should be rejected. He said non-gas revenue responsibility should be shifted to large interruptible customers, who at current rates, contribute $537,475, about 2.8%, to MDU's total non-gas costs but account for 27.2% of total Montana annual throughput. Mr. Donkin's proposed class revenues are shown in Table 9.

Table 9

MCC's Proposed Non-gas Revenues

Customer class	**Current non-gas cost revenues**	**MCC proposed non-gas cost revenues**	**Increase/decrease**	**% change**
Residential	$11,915,303	$11,463,129	($452,174)	-3.795%
Firm General Service	$6,059,173	$5,829,233	($229,940)	-3.795%
Small Interruptible	$761,828	$732,917	($28,911)	-3.795%
Large Interruptible	$537,475	$1,000,242	$436,414	86.1%

90. Mr. Donkin's class revenues were based on MCC's proposed total non-gas revenue requirement of about $19 million, presented by MCC's witness, Clark. Mr. Donkin developed his class revenues by first charging the large interruptible customer class $0.25 per dkt for test year throughput of 4,000,969 dkt. This produced $1,000,242. Next, he reduced the revenues of the other customer classes by an equal percent necessary to arrive at the proposed non-gas revenue requirement. He noted that even though his proposal would increase large industrial class revenues by 86%, that class' rate of return would still be -9.3%.

91. He acknowledged that several large interruptible customers may have bypass opportunities if their rates are raised too much. He therefore proposed a margin sharing/flexible pricing alternative for apportioning non-gas revenue responsibility. Under this approach, rates for the large industrial class would be set at MDU's proposed amount but MDU would be allowed to price the service on a competitive basis subject to a price cap. MDU could keep 20% of large interruptible non-gas revenue in excess of $537,475. He said this approach should give MDU an incentive to price large interruptible service at higher levels than it has proposed in this case, but not so high that customers would bypass the system.

MCC's Proposed Rate Design

92. Mr. Donkin recommended that the Commission reject MDU's proposal to increase monthly customer charges asserting that, based on variable embedded costs, a residential monthly charge of $6.25 or less would be appropriate. A higher monthly charge would cause existing residential customers to pay too much for the customer component of their rate and too little for the commodity cost of gas service.

93. He also recommended that the Commission reject MDU's proposal for a distribution delivery stabilization mechanism (DDSM) for two reasons: first, such weather normalization mechanisms distort price signals by increasing or decreasing rates in subsequent periods relative to actual costs, and second they reduce a utility's business risk relative to the risk used to calculate the utility's cost of capital. He also noted that MDU's proposed DDSM would conflict with Commission policy as reflected in Order No. 4914a.

MDU Rebuttal Testimony

Marginal Costs

94. Ms. Aberle disagreed with Mr. Donkin's characterization of her marginal cost study. She said Mr. Donkin's criticism that her study did not focus on the change in total costs from increasing or decreasing gas sendout failed to recognize the system-related costs associated with adding new customers.

95. She also disagreed with Mr. Donkin's conclusion that her study overstated the marginal cost of customer growth. She said Mr. Donkin appeared to reach his conclusion based on a comparison of the average marginal distribution cost per customer and the average annual distribution revenues collected from the residential class under proposed rates. She said Mr. Donkin inappropriately compared embedded revenue requirements and average marginal costs. She identified several adjustments to the marginal cost calculation that could be made to make a comparison to embedded costs appropriate. She also pointed out that MDU's line extension policy requires contributions from new customers if rates would not recover the incremental investment.

Embedded Costs

96. Ms. Aberle disagreed with Mr. Donkin that none of the embedded distribution mains investment should be classified as customer-related. She maintained that classifying a portion of the distribution mains cost as customer-related is a standard practice throughout the gas industry. She referenced a 1989 Gas Distribution Rate Manual prepared by the NARUC staff subcommittee on gas rates which found that a portion of distribution system capital costs can be classified as customer related because there is a minimum size main necessary to connect a customer to the system which affords the customer an opportunity to take service. She also disagreed with Mr. Donkin that a portion of distribution mains costs should be classified as energy-related, maintaining that mains investment does not vary as more or less gas is used. She said the fact that customers exist and require a system to deliver natural gas on demand on the coldest day of the year supports classifying and allocating embedded distribution costs on the basis of customers and peak day demand.

97. Ms. Aberle also disagreed with Mr. Donkin's recommendation to classify service lines investment 50 percent customer-related and 50 percent demand-related. She said service lines are clearly customer-related since investment varies directly with the number of customers

served not the amount of utility service provided. She also said the NARUC gas distribution rate design manual discussed above supports classifying service lines investment as customer-related.

98. Ms. Aberle rejected Mr. Donkin's recommendation to allocate administrative and general expenses 50 percent based on coincident peak day demands and 50 percent on annual throughput. She stated that administrative and general expenses are incurred for overall support of all other functions and that is why they should be allocated on the basis of other operation and maintenance expenses. Again, Ms. Aberle said the NARUC manual supports MDU's approach.

99. According to Ms. Aberle, Mr. Donkin's recommendation to use the 50 percent demand-50 percent throughput allocator for general and common plant, ad valorem taxes, other taxes and gas in underground storage does not follow the principle of cost causation. General and common plant consists of such things as office buildings, furniture, computer equipment and transportation equipment. She maintained that general and common plant supports the distribution function and the allocation of the costs of these investments should reflect that.

Rate Design

100. Ms. Aberle criticized Mr. Donkin's proposed rate design, asserting that he provided no basis for his $0.25 per dkt rate, which was used to assign revenues to the large interruptible customer class. She also said increasing non-gas rates for the large interruptible class would jeopardize MDU's ability to fully realize the increased revenues (presumably due to the risk of bypass). She maintained that the large increase proposed by Donkin contradicts several of the rate design objectives he subscribed to including equity, revenue and earnings stability, rate continuity, understandability and customer acceptance.

101. Ms. Aberle dismissed Mr. Donkin's proposed margin sharing/flexible pricing proposal saying his embedded cost conclusions are wrong, and incentives exist today to price large interruptible service at the highest available price to minimize revenue erosion. She asserted that Mr. Donkin incorrectly thinks that MDU has proposed new rate levels for the large interruptible class, when, in fact, revenues for this class reflect contracts what were executed before this rate case was filed. She said the average per unit revenue from this class has ranged from a low of $0.129 per dkt to a high of $0.140 per dkt during the period 1999-2003. The average over that time period was $0.132 per dkt.

102. Ms. Aberle said Mr. Donkin's calculation of cost-based customer charges based on variable monthly embedded customer costs is inappropriate and unsound because classifying customer costs as variable is inconsistent with the theory that customer costs are fixed. She said Mr. Donkin's own embedded cost study supports a monthly charge of about $7.50 for the residential class.

103. Finally, Ms. Aberle clarified that MDU's proposed distribution delivery stabilization mechanism would only apply to the distribution component of bills. This component represents about 22% of a customer's total annual bill. Therefore, Ms. Aberle concluded the DDSM would not distort price signals. She also disagreed that the Commission's Order 4914a, referenced by Mr. Donkin, established a policy that would preclude the proposed DDSM or a similar mechanism.

PSC Cost of Service Analysis and Decisions

104. The Commission's long-standing policy is to set utility rates based on economic costs, meaning marginal, avoidable or incremental costs. Marginal cost is the increase/decrease in the total cost of production that results from increasing/decreasing the rate of production by one unit. Mathematically, it is the slope of the total cost curve at a specific level of output. The decrease in total cost associated with a decrease in production is also referred to as the avoided cost. In its first order addressing a comprehensive marginal cost study by a natural gas utility, the Commission stated that marginal cost pricing facilitates efficient resource allocation.[1] The Commission's policy was embraced by, among others, Montana Power Company (MPC) and MCC. MCC noted that using marginal costs promotes rate structures that encourage conservation, efficiency and equity. Since its first order on marginal cost pricing the Commission has established administrative rules requiring utilities to file an analysis of marginal costs to support rate design proposals. Of course, marginal cost estimates are not the only determinant of Commission-approved rates. First, prices must recover the allowed revenue requirement, which is based on accounting costs that may be more or less than marginal costs. A range of public policy considerations also typically informs Commission pricing decisions.

105. The evidentiary record on marginal costs in this proceeding consists of MDU's analysis and Mr. Donkin's relatively cursory critique, along with discovery and late filed exhibits

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[1] See Montana Power Company docket no. 87.8.38, order no. 5410, paragraph 106.

that clarify and, in some cases, expand on MDU's analysis. Additionally, the Commission may take administrative notice of the body of prior Commission orders regarding natural gas utility marginal costing and pricing issues. Consistent with the Commission's well-grounded, established policy to base pricing decisions on analyses of marginal costs, this order analyzes the marginal cost information in this proceeding, referring to prior Commission orders where relevant. Using the marginal cost model described above, the Commission first analyzes the record with regard to marginal costs for gas supply, distribution and customer cost functions. The Commission assesses the MDU-MCC Stipulation in light of its marginal cost findings.

106. In this docket, Mr. Donkin articulated a number of pricing principles that are consistent with marginal cost-based prices including conservation, efficient use of facilities and resources and equity. He also identified a number of pricing principles that are public policy-related, such as understandability, customer acceptance and continuity. However, in contrast to previous MDU gas dockets, Mr. Donkin did not perform an in-depth, independent marginal cost analysis. Instead, after analyzing MDU's approach to estimating marginal costs, he concluded the approach was flawed and he developed an alternative embedded cost analysis. Mr. Donkin reasoned that marginal cost analysis is more relevant to utility ratemaking when there is a significant difference between marginal and embedded costs, for example when the marginal cost of gas supply greatly exceeds the average cost. In Mr. Donkin's view, since gas supply prices are now determined by market forces and a local distribution utility's non-gas marginal costs in the short- and intermediate-run are far below embedded costs, basing rates on marginal costs will not likely promote efficient consumption or equity in the recovery of non-gas costs.

Marginal Gas Supply Costs

107. In Order 5856b, docket D95.7.90, the Commission criticized both MDU and MCC for not analyzing gas costs more thoroughly. The Commission rejected proposals to rebalance rates finding that it would not serve the public interest to rebalance based on non-gas costs when the majority of MDU's costs are gas-related.[2] The Commission found that marginal gas costs must be part of cost of service for rate design.[3] In this case, while both MDU and MCC discuss gas supply costs briefly, neither party provided the kind of thorough analysis the Commission

[2] Docket No. D95.7.90, Order No. 5856b, paragraph 189.
[3] Id. paragraph 191.

determined was necessary in order 5856b. The Commission will require MDU to analyze marginal gas costs in future proceedings for non-gas rate design purposes.

108. MDU's marginal gas cost was derived from embedded costs and adjusted to reflect pro forma 2004 information. Ms. Aberle stated that MDU used this approach because gas costs are not an issue in this proceeding. TR 32. Ms. Aberle estimated marginal gas costs of $6.53 per dkt and $5.473 per dkt for firm and interruptible customers, respectively, including line losses.

109. In prefiled testimony, Mr. Donkin asserted that marginal gas costs are not relevant in this proceeding because MDU recovers these costs through a gas cost tracking mechanism. However, at the hearing, Mr. Donkin stated that marginal gas costs could be relevant to non-gas cost allocation and rate design. TR 76-78. Mr. Donkin stated that MDU's marginal gas cost consists of the cost of acquiring gas supply from producers or marketers, including variable transportation costs. Because MDU pays its pipeline supplier demand and/or reservation charges pursuant to long-term service agreements, Mr. Donkin determined that these charges are not avoidable and should not be included in marginal gas supply costs. Storage costs are avoidable, in Mr. Donkin's view. TR 65. Mr. Donkin estimated the marginal cost of gas supply at between $5.50 per Dkt and $6.00 per dkt in summer 2004.

110. Table 10 illustrates the relevance of marginal gas costs to cost allocation and rate design. The allocation of costs to customer classes, reconciled to the revenue requirement, varies depending on the chosen marginal cost of gas supply, holding other cost components equal. Although in this case the differences appear relatively small, some general service customers, for example, could pay hundreds of dollars more per year with MDU's gas cost estimate compared to MCC's. Information on the marginal cost of gas can also be relevant to deciding whether to recover non-gas costs through monthly Basic Service Charges or per dkt charges.

Table 10

Marginal cost revenues reconciled to revenue requirement

	Residential	**Firm General Service**	**Sm. and Lg Interruptible**	**Revenue Requirement**
MDU gas cost estimate	$57,141,151	$27,432,729	$634,410	$85,208,290
MCC low gas cost estimate	$57,497,827	$26,994,585	$715,878	$85,208,290

111. Neither MDU nor MCC provided thorough economic analyses to support their marginal gas cost estimates, in spite of the Commission's findings in Order 5856b. To the extent MDU's and MCC's marginal gas cost estimates are forward looking, both appear to be short-run; Mr. Donkin's estimate is based on summer 2004 and MDU's is perhaps based on 2004 as a whole. The record is essentially void of information on the appropriate basis for MDU's marginal gas supply costs. At the hearing, the Commission requested that MDU provide a copy of its annual 10-year projection of gas rates as a late-filed exhibit. The 10-year projection, dated February 2004, shows MDU's estimates of nominal gas costs for the period 2004 through 2013. If these projected nominal gas costs are converted to 2006 dollars using MDU's expected inflation rate of 2.05%, the exhibit shows declining real costs that average \$5.51 per dkt.[4] Superficially, MCC's marginal gas cost estimate appears to better reflect forward looking gas costs. However, the analysis underlying MDU's 10-year projection was not evaluated in this proceeding. For example, notes accompanying MDU's projection indicate that the gas costs include costs for delivery to town border stations, i.e., they include costs related transporting purchased gas to MDU's distribution system. MDU's transportation and storage costs derive from contracts with Williston Basin Interstate Pipeline executed pursuant to Federal Energy Regulatory Commission tariffs. The record contains some information on these pipeline charges but not enough to definitively determine whether they represent incremental or avoidable costs. Again, Mr. Donkin argued that transportation costs are not avoidable because they are fixed in long-term contracts. If Mr. Donkin is correct, both MDU's projections, and Mr. Donkin's short-run cost estimates may overstate longer-term marginal gas costs. For purposes of its analysis, the Commission uses \$5.50 per dkt. In future proceedings, MDU must more thoroughly evaluate forward-looking gas costs as part of its marginal cost studies. Included in the evaluation must be a thorough analysis of how Williston Basin Interstate Pipeline-related transportation costs are incurred and how those costs are allocated to rate classes. Alternatively, as previously suggested by the Commission, an annual gas tracker case could also be an appropriate forum for evaluating gas cost of service and rate design issues, including the sources of transportation costs and the proper allocation of those costs.[5]

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4 MDU's calculation of real carrying charges assumes an inflation rate of 2.05%. See late filed exhibit 2, p. 10.
5 Docket No. D95.7.90, Order 5856b, paragraph 232.

Marginal Distribution Costs

112. MDU estimated marginal distribution capacity-related costs using a method that is similar to the one it used in docket D95.7.90. Ms. Aberle used costs associated with a combination of historic and projected capacity expansion projects to derive a cost for incremental peak day distribution capacity. She screened project costs to eliminate any costs associated with pipe less than 2 inches in diameter as a means of removing costs that might be associated with service lines, which she considers customer-specific costs. DR PSC-027 and PSC-037. Using actual costs for 1999-2003 and projected costs for 2004-2008, Ms. Aberle determined that incremental distribution capacity-related costs are $10.65 per peak day dkt.

113. Mr. Donkin's critique of MDU's marginal cost analysis was not specific to individual, non-gas cost functions. Mr. Donkin asserted that Ms. Aberle's non-gas marginal cost analysis focused primarily on costs related to adding new customers, instead of properly focusing on costs related to changes in demand by existing customers. In docket D95.7.90 Mr. Donkin used a method similar to MDU's method in this case, except Mr. Donkin relied on actual recently completed distribution capacity projects. DR PSC-037. In that case, the Commission found that the difference between the marginal distribution costs estimated by MDU and MCC was due to Mr. Donkin's use of actual recent distribution investment experience.[6] While commending MDU for using a forward-looking approach, the Commission ultimately adopted Mr. Donkin's method finding it similar to the analysis approved in Docket 88.11.53.[7]

114. The Commission finds that its previously adopted method remains reasonable. Applying this method to the actual recent distribution capital investments identified in Ms. Aberle's marginal cost analysis (1999 – 2003) results in a marginal capacity-related distribution cost of $7.88 per peak day dkt. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds that this is a reasonable adjustment to MDU's marginal cost analysis.

Marginal Customer Costs

115. Ms. Aberle's calculation of marginal customer-related costs is similar to her calculation of marginal capacity-related distribution costs. First, for each customer class she

6 Docket D95.7.90, Order 5856b, paragraph 163
7 Id, paragraph 192.

assembled current costs for the capital equipment necessary to connect a new customer to the system: a main extension, service line, meter and regulator. She restated these costs in 2006 dollars. Each of these costs for each customer class is grossed up for general and common plant costs and annualized. Then she added customer-related operation and maintenance expenses, administrative and general expenses, taxes other than income taxes and a working capital component.

116. Again, Mr. Donkin did not critique Ms. Aberle's non-gas cost analysis by cost function. However, his assertion that Ms. Aberle's analysis inappropriately focuses on the cost of adding new customers rather than the cost of serving existing customers makes the most sense in the context of her method for estimating marginal customer costs, especially given his prior testimony on distribution costs as discussed above. In docket D95.7.90 the Commission approved Mr. Donkin's method for determining the capital costs underlying marginal customer costs. In that case Mr. Donkin excluded investments in main extensions and service lines. This was consistent with long-standing Commission practice. In its first natural gas utility marginal cost of service docket the Commission stated that including meter and regulator costs while excluding costs for main extensions and service lines turns on the concept of opportunity costs.[8] Meters and regulators have opportunity costs in that a customer's decision to continue receiving service prevents the Company from using the meter and regulator to serve another customer. In contrast, once a main extension and service line are in place the investment is a sunk cost with respect to existing customers;[9] MDU could not cost effectively redeploy the main extension and service line if the customer decides to discontinue gas service. The record in this case appears to support the Commission's long-standing approach. In response to a data request, Ms. Aberle acknowledged the fungibility of meters and regulators and agreed that mains and services can not be cost effectively redeployed. DR PSC-027. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds excluding the capital costs for main extensions and service lines from MDU's marginal cost analysis remains reasonable. A comparison of the resulting marginal customer costs is shown in table 11.

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[8] Docket 87.8.38, Order 5410, paragraph 144.
[9] Id, paragraph 145.

Table 11

Marginal Customer-related Costs ($/month)

	Residential	Firm General	Sm. Interrup.	Lg Interrupt.
MDU estimate	$25.48	$59.20	$178.38	$1,012.73
Exclude main ext., service line	$7.19	$31.59	$150.77	$853.65

Other Marginal Cost Issues

117. In a marginal cost analysis carrying charges typically reflect the total cost of long-lived capital assets converted to a series of annual costs. For example, as discussed above, Aberle's estimate of marginal distribution capacity-related costs started with investments in distribution capacity. The total cost of these investments must be converted into an annual cost that can be allocated to customers. Ms. Aberle uses nominal carrying charges throughout her marginal cost analysis. In docket D95.7.90 the Commission stated that real carrying charges should be used to annualize distribution and customer costs.[10] When asset prices are increasing because of inflation, real carrying charges start at a lower value than nominal carrying charges, but rise from year to year. Consequently, in docket D95.7.90 the Commission found that using nominal carrying charges exaggerates distribution and customer cost estimates relative to using real carrying charges.

118. At the hearing the Commission asked Aberle to estimate marginal distribution and customer costs using real carrying charges. Late Filed Exhibit No. 2 contains the results. In the absence of a specific alternative marginal cost analysis from MCC, the Commission finds that using the real carrying charges in Late Filed Exhibit No. 2 is a reasonable adjustment to Ms. Aberle's marginal cost analysis. The result is slightly lower marginal distribution costs and marginal customer costs.

Summary of Marginal Costs

119. Table 12 compares the marginal costs from Aberle's analysis to the marginal costs that result from the Commission's adjustments described above.

120. Note that MDU's initial marginal cost analysis did not estimate separate marginal customer costs for firm general service customers served by small meters and large meters. The Commission requested a separate cost breakdown at the hearing and MDU provided the

[10] Docket D95.7.90, Order 5856b, paragraph 197.

breakdown in Late Filed Exhibit No. 2. The Commission also notes that while MDU converted the distribution capacity cost into a cost per dkt for interruptible customers, the Commission has previously determined that it is theoretically incorrect to allocate peak day demand costs to interruptible customers.[11]

Table 12

Comparison of Marginal Costs: MDU vs. Commission-adjusted

Marginal Cost Component	Residential	Firm General Service <500 cf/h	Firm General Service 500+ cf/h	Small Interruptible	Large Interruptible
MDU analysis					
Gas supply ($/Dkt)	$6.53	$6.53	$6.53	$5.473	$5.473
Dist. capacity ($/mcfd)	$10.65	$10.65	$10.65	$0.029	$0.029
Customer ($/mo)	$25.48	$59.20	$59.20	$178.38	$1,012.73
MDU analysis w/ adjustments					
Gas supply ($/Dkt)	$5.50	$5.50	$5.50	$5.50	$5.50
Dist. capacity ($/mcfd)	$6.66	$6.66	$6.66	$0.01825	$0.01825
Customer ($/mo)	$6.82	$10.41	$48.53	$136.36	$816.46

Rate Design

121. Using the adjusted marginal costs from Table 12 above, class marginal cost-based revenues are shown in Table 13. Table 13 also shows the class revenues that would result from an equal percent reconciliation to the proposed revenue requirement implied by the stipulation between MDU and MCC.

[11] Docket 87.8.38, Order 5410, paragraph 154.

Table 13

Commission-adjusted Marginal Cost Revenues and Reconciled Revenues

Marginal cost based revenues	Total	Residential	Firm Gen <500 cf/h	Firm Gen 500+ cf/h	Small Interruptible	Large Interruptible
Gas supply	$54,049,842	$34,039,467	$6,320,089	$13,235,239	$455,098	$0
Distribution	$514,083	$297,922	$55,105	$115,398	$13,992	$31,666
Customer	$7,239,728	$5,303,068	$768,258	$1,052,325	$67,089	$48,988
Total	$61,803,703	$39,640,457	$7,143,452	$14,402,962	$536,178	$80,654
Test year revenue*	$83,358,279	$52,329,434	$9,812,498	$19,464,181	$1,214,691	$537,475
Stipulated increase	$124,625					
Proposed revenue	$83,482,904					
Reconciliation factor	1.356233					
Reconciled marginal cost revenues	$83,482,904	$53,545,343	$9,649,197	$19,455,162	$724,256	$108,946
Percent change	0.15%	2.32%	-1.66%	0.05%	-40.38%	-79.73%
Stipulated revenue		$52,407,192	$9,842,018	$19,481,529	$1,214,691	$537,475

* Test year revenues from Statement H, p. 3 and Statement M, p. 1

122. Attachment A to this Order compares MDU's current rates to the rate design stipulated to by MDU and MCC along with the rate designs advocated by each party in prefiled testimony.[12] As shown in the attachment, MDU proposed increases in both basic monthly service charges and per-dkt distribution rates for residential and firm general service customers. MDU's rates were designed to recover approximately $1.5 million of additional revenue annually. MCC advocated a net reduction in MDU's annual revenues of $274,611. Additionally, Mr. Donkin recommended rebalancing class revenue requirements by reducing per-dkt distribution rates for the residential, firm general service and small interruptible classes and increasing the per-dkt distribution rate for the large interruptible class. Mr. Donkin recommended maintaining current basic monthly service charges for all customer classes. The Stipulation slightly increases the basic monthly service charges for the residential and firm general service classes and produces additional annual revenues of $124,625, or about 0.15 percent of test year revenues.

[12] The attachment focuses on the residential and firm general service classes since these are the customer classes covered by the stipulation. MCC initially recommended rate adjustments for interruptible customers.

123. The Commission finds the rate adjustments in the Stipulation to be within a zone of reasonableness when placed in the context of the adjusted marginal costs outlined above. In the past the Commission has preferred to recover some of a rate increase in the commodity (i.e., per-dkt) rate so customers have an opportunity to avoid some of the increase by changing consumption behavior.[13] However, in this case the overall increase is so small that, for all practical purposes, there is no difference in a customer's final bill under various rate design scenarios, as shown in the table at the bottom of Attachment A. Additionally, the adjusted marginal cost analysis indicates that current Basic Service Charges are below marginal costs, while the distribution demand costs, when converted to per-dkt rates, are well below current distribution rates.

124. Finally, as this Order adopts the Stipulation between MDU and MCC, the Commission finds that the various other tariff changes MDU initially proposed related to its operating rules and the distribution delivery stabilization mechanism are moot.

III. CONCLUSIONS OF LAW

125. All findings of fact, discussion, and decisions above that can properly be categorized as consclusions of law and should be so categorized to preserve the integrity of this final order are adopted here as conclusions of law.

126. MDU is a public utility as defined in § 69-3-101, MCA. The PSC has jurisdiction over MDU in regard to the matter presented pursuant to §§ 69-3-102, 69-3-103, 69-3-106, et al., MCA. MDU's application and supplement were properly filed and processed.

ORDER

IT IS HEREBY ORDERED that the above order is the Final Order in this matter, MDU shall comply with the provisions of this Final Order, and MDU shall file tariffs in compliance with this Final Order.

Done and dated this 10th day of May, 2005, by a vote of 4 – 1.

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[13] Docket D95.7.90, Order 5856b, paragraph 235.

	A	B	C	D	E	F	G	H	I	J
1	**Summary of MDU-MCC stipulation in D2004.4.50**								**Attachment A**	
2										
3		**Current rates**		**Stipulated rates**		**MDU testimony**		**MCC testimony**		
4	Rate Schedule	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	Basic Service Charge	Distribution Delivery Charge	
5	Residential Rate 60	$6.25	$1.14	$6.35	$1.14	$6.99	$1.203	$6.25	$1.067	
6	Firm General Service Rate 70									
7	Meters rated < 500 cf/h	$10.00	$1.37	$10.40	$1.37	$12.16	$1.367	$10.00	$1.302	
8	Meters rated 500+ cf/h	$21.25	$1.37	$22.05	$1.37	$24.32	$1.456	$21.25	$1.302	
9										
10										
11	**Allocation of revenue increase & results of stipulated rate design**									
12	Rate class	Billing units	Dkt	Current Distribution Revenues	Stipulated Distrubution Revenues	Gas commodity expense	Total Current Revenue	Total Stipulated Revenue	Difference	pct
13	Residential Rate 60	777,576	6,188,994	$11,915,303	$11,993,061	$40,414,131	$52,329,434	$52,407,192	$77,758	0.15%
14	Firm General Service Rate 70									
15	Meters rated < 500 cf/h	73,800	1,149,107	$2,308,829	$2,338,349	$7,503,669	$9,812,498	$9,842,018	$29,520	0.30%
16	Meters rated 500+ cf/h	21,684	2,406,407	$3,750,343	$3,767,691	$15,713,838	$19,464,181	$19,481,529	$17,347	0.09%
17	Stipulated revenue increase								$124,625	
18										
19	**Monthly residential bill under various rate designs**									
20		**Current**			**Stipulation**					
21	Basic Service Charge	$6.25	$6.25	$6.30	$6.35					
22	Distribution Delivery Charge	$1.1400	$1.1526	$1.1463	$1.1400					
23	Assumed gas commodity rate	$6.5000	$6.5000	$6.5000	$6.5000					
24	Annual dkt		**Average monthly bill amount**							
25	70	$ 50.82	$ 50.89	$ 50.90	$ 50.92					
26	75	$ 54.00	$ 54.08	$ 54.09	$ 54.10					
27	80	$ 57.18	$ 57.27	$ 57.28	$ 57.28					
28	85	$ 60.37	$ 60.46	$ 60.46	$ 60.47					
29	90	$ 63.55	$ 63.64	$ 63.65	$ 63.65					
30	95	$ 66.73	$ 66.83	$ 66.83	$ 66.83	**Average consumption**				
31	100	$ 69.92	$ 70.02	$ 70.02	$ 70.02					
32	105	$ 73.10	$ 73.21	$ 73.21	$ 73.20					
33	110	$ 76.28	$ 76.40	$ 76.39	$ 76.38					

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

Greg Jergeson
GREG JERGESON, Chairman

Brad Molnar
BRAD MOLNAR, Vice-Chairman, Voting to Dissent

DOUG MOOD, Commissioner

Robert H Raney
ROBERT H. RANEY, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:
Connie Jones
Connie Jones
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. <u>See</u> 38.2.4806, ARM.

CERTIFICATE OF SERVICE

I hereby certify that a copy of **FINAL ORDER 6580a** issued in D2004.4.50 in the matter of Montana-Dakota Utilities Co. has today been served on all parties listed on the Commission's most recent service list, created 4/23/04, by mailing a copy thereof to each party by first class mail, postage prepaid.

Date: May 12, 2005

Katy Bogy
For The Commission

Intervenors:

Montana Consumer Counsel

RECEIVED BY
14 PM 4: 53
PUBLIC SERVICE COMMISSION

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF MONTANA-DAKOTA UTILITIES CO., Application for Authority to Increase Rates for Natural Gas Services in its Montana Service Areas	))))	UTILITY DIVISION D2004.4.50 STIPULATION

COMES NOW, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (Montana-Dakota) and the Montana Consumer Counsel (MCC) and agree and stipulate as follows:

1. On April 1, 2004, Montana-Dakota filed with the Commission an Application for authority to implement a general rate increase in the rates it is authorized to charge for natural gas service in Montana. The requested rate increase, if granted in its entirety, would have raised an additional $1.51 million dollars in annual revenues. The Application was denominated PSC Docket D2004.4.50.

2. The MCC intervened in the docket, opposing both the proposed rate increase and the manner in which Montana-Dakota proposed to allocate its revenue deficiency between customer classes, and the manner in which Montana-Dakota proposed to design the final authorized rates established in this docket.

3. The pre-filed testimony of the MCC expert witnesses was filed in this docket on July 30, 2004. In that pre-filed testimony, the MCC contends that the Commission should decrease the annual revenues that Montana-Dakota is currently authorized to collect in Montana by $248,245. Additionally, the MCC has proposed an alternative allocation of the revenue deficiency between customer classes and alternative rate design to that proposed by Montana-Dakota in its Application in this docket.

4. The MCC developed revenue requirement in this case utilized a weighted cost of capital of 8.45%, including a cost of equity of 9.75%. Montana-Dakota contests the validity and the adequacy of the MCC developed cost of capital in this docket. In addition, the MCC has proposed other adjustments to the Montana-Dakota revenue requirement in this case.

5. A contested case hearing was held in this docket on November 17, 2004. However, a quorum of Commissioners was not available for the hearing, and it was heard by Commissioner Thomas Schneider, acting as hearing officer.

6. For settlement purposes, a fair and equitable resolution of the issues between Montana-Dakota and the MCC, one which would result in the establishment of just and reasonable rates, would be:

A. Montana-Dakota should be authorized to increase the Basic Service Charges contained in its Rates 60 and 70 as follows:

1. Rate 60, by 10 cents per month;
2. Rate 70, small meter, by 40 cents per month;
3. Rate 70, large meter, by 80 cents per month.

The above specified change in the Basic Service Charges is estimated to generate an additional $124,625 in annual revenue.

B. The agreed upon rate change should be implemented immediately, if possible for service rendered on and after February 1, 2005.

7. For Montana-Dakota, an essential component of this Stipulation is provision 6 B above, as no interim rate relief of any kind was authorized in this docket.

8. The Commission, after the completion of contested case proceedings in this docket, should be moved in its discretion to issue a final order approving, adopting, and

implementing the terms of this Stipulation.

9. The parties to this Stipulation present it to the Commission as a reasonable settlement of the issues raised in this docket. Neither party's position in this docket is accepted by the other party by virtue of their entry into this Stipulation, nor does it indicate their acceptance, agreement, or concession to any rate making principle, cost of service determination, or legal principle embodied, or arguably embodied, in this Stipulation.

10. The various provisions of this Stipulation are inseparable from the whole of the agreement between the parties to the Stipulation. The reasonableness of the proposed settlement set forth in this Stipulation is critically dependent upon its adoption, in its entirety, by the Commission. If the Commission decides not to adopt, in its entirety, the proposed settlement set forth in this Stipulation, then the entire Stipulation is null and void, no party to the Stipulation is bound by any provision of it, and it shall have no force or effect whatsoever.

Respectfully submitted January 14, 2005.

MONTANA CONSUMER COUNSEL

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