Service Date: April 2, 1987

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

* * * * *

IN THE MATTER of the Application	)	
of MONTANA-DAKOTA UTILITIES for	)	UTILITY DIVISION
Authority to Establish Increased	)	DOCKET NO. 86.5.28
Rates for Electric Service.	)	ORDER NO. 5219b

ERRATA SHEET TO ORDER NO. 5219b

Page ii of the TABLE OF CONTENTS, PART F, under OTHER ISSUES, the entry Wester should read Western.

Page 12, under the column headed Difference the fourth number 1.45 should read 1.42.

Page 19, Finding of Fact 68, HWI should read HWI.

Page 22, Finding of Fact 75, line 5, the period after adjustments should be a semi colon.

Page 37, Finding of Fact No. 137 should read 139. This causes each succeeding Finding of Fact No. to increase by one. The original Finding of Fact No. 139 thus becomes No.140.

Page 44, Finding of Fact No. 158, the last line should be deleted.

Page 60, last line of Finding of Fact No. 209 (revised), the rate under Big Stone of 4.17% should read 4.26%.

Page 70, third line from the bottom of Finding of Fact No. 234 (revised), the word forecasting should read forecast.

Page 89, the first line should be indented 5 spaces.

Page 98, Finding of Fact No. 29 should read 330 (revised).
Page 98, Finding of Fact No. 30 should read 331 (revised).

Page 99, Finding of Fact No. 31 should read 332 (revised).
Page 99, Finding of Fact No. 32 should read 333 (revised).
Page 99, Finding of Fact No. 33 should read 334 (revised).
Page 99, Finding of Fact No 34 should read 335 (revised).

Page 100, Finding of Fact No. 36 should read 337 (revised).
Page 100, Finding of Fact No. 37 should read 338 (revised).

Page 103, Finding of Fact No. 43 should read 344 (revised).

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

* * * * *

IN THE MATTER of the Application of MONTANA-DAKOTA UTILITIES for Authority to Establish Increased Rates for Electric Service.	))))	UTILITY DIVISION DOCKET NO. 86.5.28 ORDER NO. 5219b

APPEARANCES

FOR THE APPLICANT:

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Mary Wright, Consumer Counsel Staff Attorney, 34 West Sixth Avenue, Helena, Montana 59620, appearing on behalf of the consuming public of the State of Montana

FOR THE COMMISSION:

Geralyn Driscoll, Staff Attorney

BEFORE:

DANNY OBERG, Presiding
HOWARD L. ELLIS, Commissioner
JOHN DRISCOLL, Commissioner

FINDINGS OF FACT

PART A

BACKGROUND

1. On May 23, 1986, Montana-Dakota Utilities Company (MDU, Company, Applicant) filed an application with the Commission seeking a general rate increase for electric service. MDU requested $4,549,702 in additional annual revenues. Rate schedules filed with the application reflect an overall increase of 14.6 percent for electric service rendered in Montana.

2. Included in the May 23rd filing was a request for interim relief in the amount of $1,940,753.

3. On June 9, 1986, the Commission issued a Notice of Application and Proposed Procedural Order. After considering requested amendments, the Commission issued a final Procedural Order on June 30, 1986.

4. The Montana Consumer Counsel (MCC) has participated in this Docket on behalf of electric utility consumers since the inception of these proceedings.

5. On September 5, 1986, the Commission issued Interim Order No. 5219. Order No. 5219 granted $942,582 in additional revenues on an annual basis.

6. In its filing for interim relief in this Docket, MDU did not reduce rate base by the amount of unamortized gain on reacquired debt. Interim Order No. 5219 complied with a District Court decision that held against the Commission's rate base treatment of unamortized gain on reacquired debt in Docket No. 83.9.68.

7. On September 11, 1986, the Supreme Court of the State of Montana ruled that the Commission had properly reduced MDU's rate base in Docket No. 83.9.68 by the amount of unamortized gain on reacquired debt.

8. On September 15, 1986, the Commission issued Interim Order No. 5219a. This Order was issued to reflect the decision of the Montana Supreme Court concerning the issue of unamortized gain on reacquired debt. The result of this adjustment was a reduction of MDU's interim annual revenue increase by $58,075 from $942,582 to $884,507.

9. On October 16, 1986, the Commission issued a Notice of Public Hearing in Docket No. 86.5.28.

10. On November 11 and 12, 1986, pursuant to the Notice of Public Hearing, a hearing was held in the Petroleum Room of the Jordan Hotel, Glendive, Montana. The Commission also held satellite hearings on December 10, 1986, in the Sheridan County Court House in Plentywood and in the Friendship Room, Nemont Telephone Building, Scobey, Montana.

PART B

RATE OF RETURN

Capital Structure

11. Applicant's witness, Mr. John Renner, presented MDU's anticipated 1986 average capital structure in his prefiled direct testimony. Mr. Renner allocated the capital structure between natural gas and electric operations based on net plant plus construction work in progress. He arrived at the following capital structure for the Company's electric operations (MDU Exh. A, Statement F, Rule 38.5.146, p. 1 of 2):

Description	Average Balance (000)	Imputed Structure (000)	Capital Ratio
First Mort. Bonds	$188,473	$153,982	43.907%
Other L.T. Debt	30,350	30,350	8.654
Preferred Stock	49,050	40,074	11.427
Common Equity	154,583	126,294	36.012
	$422,456	$350,700	100%

12. Included in the first mortgage bonds total of $188,473,000 is a $25,000,000 bond which was expected to be issued during 1986. MDU increased that amount by $10,000,000 in rebuttal testimony. The effect this additional debt has on the 1986 average capital structure is shown below (MDU Exh. D, Statement F, Rule 38.5.146, p. 1 of 2, Updated):

	Average	Imputed

Description	Balance (000)	Structure (000)	Capital Ratio
First Mort. Bonds	$193,473	$158,067	44.553%
Other L.T. Debt	30,350	30,350	8.555
Preferred Stock	49,050	40,074	11.295
Common Equity	154,583	126,294	35.597
	$427,456	$354,785	100%

13. The Company's Pollution Control Revenue Bonds and REA debt are directly assigned to the electric operations and are grouped above as "Other L.T. Debt".

14. MCC Witness, Mr. Basil Copeland Jr., also allocated the capital structure between natural gas and electric operations based on net plant plus construction work in progress. His proposed capital structure is identical to Mr. Renner's original proposal listed in Finding of Fact No. 11 (MCC Exh. No. 4, Exh. BLC-2, Sch. 5).

15. In previous MDU rate orders, such as Order No. 4834c of Docket No. 81.7.62 and Order No. 5036a of Docket No. 83.9.68, the Commission has consistently allocated MDU's capital structure between natural gas and electric operations based on gross plant plus construction work in progress rather than net plant plus construction work in progress. Neither party's testimony explained why the allocation procedure should be changed. The Commission recognizes that there are several logical ways to allocate MDU's capital structure, but will not change the current procedure without convincing evidence to do so.

16. Both parties were requested to submit a Late Filed Exhibit reallocating the capital structure in accordance with Findings of Fact Nos. 13 through 16 of Order No. 5036a (the last MDU electric rate order).

17. MCC submitted the following revised capital structure (MCC Late Filed Exh. No. 3):

Description	Average Balance (000)	Imputed Structure (000)	Capital Ratio
First Mort. Bonds	$188,473	$153,486	43.894%

Other L.T. Debt	30,350	30,350	8.680
Preferred Stock	49,050	39,945	11.424
Common Equity	154,583	125,887	36.002
	$422,456	$349,668	100%

18. The Company submitted its revised capital structure in a letter to the Commission which was received December 10, 1986:

Description	Average Balance (000)	Imputed Structure (000)	Capital Ratio
First Mort. Bonds	$193,473	$155,552	44.491%
Other L.T. Debt	30,350	30,350	8.681
Preferred Stock	49,050	39,436	11.280
Common Equity	154,583	124,285	35.548
	$427,456	$349,623	100%

19. The two capital structures are not equal for two reasons. First, MCC's allocation ignores common plant and common construction work in progress. Second, MCC did not address the additional $10,000,000 of debt.

20. The differences are very small, but the capital structure submitted by MDU more accurately reflects the Company's average capital structure. Therefore, the Commission accepts the revised capital structure submitted by MDU which is allocated on the basis of gross plant plus construction work in process.

COST OF CAPITAL

First Mortgage Bonds

21. MDU revised the proposed amount and cost of debt in its rebuttal testimony (MDU Exh. D, Statement F, Rule 38.5.146 p. 1 of 2 Updated). The revision was made to reflect an increase in the amount of debt to be issued during the year and to reflect an increase in the expected cost to issue the new debt.

22. During the hearing, Mr. William C. Glynn of MDU discussed the cost of issuing new debt:

> ... When I prepared my rebuttal testimony, which was maybe forty-five days ago, at that time interest rates were probably near the peak of the last six months period, and at that time, and I indicated in my rebuttal testimony, the coupon rate would have been around ten percent with the issuance cost then a total all-in cost about ten and a half percent. In the last week to two weeks they have fortunately trimmed it down again, and as of today we could probably issue long term first mortgage bonds at about a coupon rate of nine and a half percent for an all-in cost then of about ten percent ... (TR pp. 212-213).

23. When questioned about the timing of the new debt issuance, Mr. Glynn stated that it was very possible that the debt would be issued as soon as the week following the hearing (TR p. 226).

24. Since the new debt is to be issued within 12 months of the test year, the Commission finds it appropriate to include this debt in the determination of the Company's required return on rate base. The Commission accepts the Company's estimated cost of new debt at ten percent. This results in an imbedded cost of 10.232 percent for first mortgage bonds.

Other L.T. Debt

25. MDU also has $30,350,000 of "Other L.T. Debt" which is comprised entirely of Pollution Control Revenue Bonds add REA debt. Both MDU and MCC agree that this class of debt is directly assignable to MDU's electric operations and has a cost of 8.222 percent.

26. The Commission agrees with the concept of directly assigning the Company's "Other L.T. Debt" because this debt was acquired specifically for the purpose of supplying electric service. The Commission accepts the 8.222 percent cost proposed by both parties.

Preferred Stock

27. The cost of preferred stock is not a contested issue in this proceeding. Both parties have proposed 9.019 percent as the embedded cost of outstanding preferred shares. The Commission accepts 9.019 percent as the cost of preferred stock.

Common Equity

Applicant

28. Based on the testimonies of Mr. William C. Glynn and Dr. Dennis Fitzpatrick, Mr. John Renner proposed an equity cost of 13.75 percent in his direct testimony.

29. In his direct testimony, Dr. Fitzpatrick concluded that the cost of common equity capital for MDU's electric utility operations in Montana was conservatively between 13.25 percent an 14.25 percent as of early May, 1986. Dr. Fitzpatrick based his estimate on the results of an analysis of the consolidated financial performance or MDU Resources Group Inc., an equity-debt risk premia analysis of MDU, and Discounted Cash Flow (DCF) analyses of MDU Resources and comparable utility companies.

30. Dr. Fitzpatrick performed DCF studies of MDU Resources and four groups of utility companies that he determined to be comparable in risk to MDU. Through DCF analysis, Dr. Fitzpatrick derived a return of 15 - 16 percent for MDU Resources. Concerning the DCF studies of the four groups of comparable companies, Dr. Fitzpatrick derived returns of 13.0 - 14.0 percent for electric companies with betas of .70, 13.5 - 14.0 percent for electric utilities with Salomon earnings per share rankings of A-, B+, or B, 13.6 - 14.1 percent for electric utilities with A or AA rated bonds and no nuclear generation or construction, and 13.2 - 14.2 percent for small combination gas/electric companies (MDU Exh. K, Sch. Nos. DBF 31-35).

31. The results of Dr. Fitzpatrick's DCF studies reflect a one percent upward adjustment for underwriting and floatation costs and the effects of dividends being paid quarterly.

32. The dividend yield figures used in Dr. Fitzpatrick's DCF analyses were derived by averaging six months of dividend yield data from a Value Line computer data base, Value Screen

Plus. The data used by Dr. Fitzpatrick were for the months of November, 1985, through April, 1986 (TR p. 153).

33. Dr. Fitzpatrick primarily relied on analysts' projections in developing the expected growth rate component of his DCF analyses (MDU Exh. K, p. 39).

34. MDU changed the requested return on equity from 13.75 to 13.50 percent during its rebuttal testimony. MDU witness, Mr. Renner, cited improved equity markets for the change (MDU Exh. D, p. 1).

MCC

35. Mr. Basil Copeland Jr. testified that the Company should be allowed the opportunity to earn an 11.5 percent return on equity. Mr. Copeland based his recommendation on DCF analysis of MDU Resources and other non-nuclear electric utilities.

36. Mr. Copeland argued that direct reliance on either historic or projected growth rates can bias the resulting DCF estimates. Mr. Copeland blamed high inflation for biasing historical growth rates. He also questioned the reliability of analyst's projections because they represent estimates for only three to five years, a time period that may not be comparable to the long term growth rates needed for DCF analysis (MCC Exh. 4, pp. 6-8).

37. Mr. Copeland analyzed the relationship between the various projected growth rates forecasted by analysts. He stated that under the constant growth assumptions of the DCF model, earnings per share (EPS), dividends per share (DPS), book value per share (BVPS), and price per share (PPS) all must grow at the same constant growth rates. Mr. Copeland testified that this assumption is frequently violated by analysts since they often forecast different growth rates for EPS, DPS, BVPS and PPS.

38. Mr Copeland used a non-constant growth model (NCGM) to transform Value Line projected growth rates, which violate the assumption discussed in Finding of Fact No. 37, into an equivalent DCF growth rate.

39. Mr. Copeland testified that Dr. Fitzpatrick's adjustments to the dividend yield discussed in Finding of Fact No. 31 should not be made. He opposed the use of Dr. Fitzpatrick's

adjustment for quarterly compounding because it is conceptually flawed. Mr. Copeland also testified that an adjustment for issuance costs would be warranted if MDU was planning to issue new common stock (MCC Exh. 4, p. 28).

Commission Analysis

40. The Commission has consistently preferred the use of DCF analysis in establishing a fair rate of return because DCF analysis is superior to all other procedures. Both MDU and MCC used DCF analysis in reaching their respective recommendations.

41. As stated in Finding of Fact No. 31, Dr. Fitzpatrick adjusted the results of his DCF analyses upward by 100 basis points to reflect issuance costs and the effects of quarterly payment of dividends.

42. The Company is not planning to publicly issue stock in the near future, but its witness advocates an adjustment to reflect issuance costs. This adjustment would, in effect, overcompensate MDU for the issuance cost on all outstanding equity, and is therefore disallowed.

43. Regarding the adjustment to reflect quarterly payment of dividends, the Commission agrees with Mr. Copeland that the adjustment is conceptually flawed. The MDU stockholder who receives a quarterly dividend can either reinvest the dividend with MDU, or use it for some other purpose. If the dividend is reinvested, it is converted to new shares of MDU common equity which increases the common equity component of the capital structure. As an increase to the equity component, this new equity is used to support growth in the Company's rate base, and then earns the same return as all other shares of MDU common equity. By setting the rate base and the capital structure on the average year basis, rather than beginning of the year basis, the Commission properly matches the Company's capital requirements with its cost of capital. Therefore, MDU's proposed quarterly dividend adjustment is disallowed.

44. The Company reduced its requested return as stated in Finding of Fact No. 34. The rebuttal testimonies of Mr. John Renner and Mr. William Glynn both cited current market conditions for reducing the requested return from 13.75 percent to 13.50 percent (MDU Exh. D, p. 1, MDU Exh. N, p. 5). The rebuttal testimony of Dr. Fitzpatrick contained no mention of current market conditions.

45. Dr. Fitzpatrick was cross examined during the hearing to determine if he thought the equity markets had improved. He responded:

> Well, I would--would say that the utility equity markets might have improved somewhat. I wouldn't state it quite as strongly as he [Mr. Renner] has. The equity markets I would have to disagree with him (TR p. 153).

Dr. Fitzpatrick's statements represent a different view of the equity markets than did the rebuttal testimonies of Mr. Glynn and Mr. Renner. This left the Commission with some question as to what the current market conditions actually were.

46. The dividend yield component of the DCF equation is derived by dividing the current dividend by the prevailing market price of a given stock and is more volatile than the growth component. Therefore, the dividend yield would tend to reflect market conditions during the time that the dividend yield was calculated. Some of the dividend yield data used by Dr. Fitzpatrick in his DCF analysis was nearly a year old at the time of the hearing. In order to determine the extent of improvement in the utility equity markets that is discussed in Findings of Fact Nos. 44 and 45, Dr. Fitzpatrick was requested to provide the Commission with current dividend yield information for MDU and his comparable groups of utility companies.

47. A comparison of the original and updated dividend yields is shown below:

Company/Companies	Original	Updated	Difference
MDU Resources	7.00%	5.93%	1.07%
Electric Companies with Beta of .70	8.00	7.15	0.85
Electric Utilities with EPA Ranking of A-, B+, or B	7.50	6.30	1.20
Electrics with A or AA Bonds & 0% Nuclear	7.60	6.18	1.45
Small Gas & Electrics	8.20	6.84	1.36

(MDU Exh. K, Sch. DBF 31 - DBF 35, MDU Late Filed Exh. No. 7.)

48. As can be seen from the above table, the dividend yields for MDU resources and the comparable utility companies have decreased significantly since the time that Dr. Fitzpatrick filed his direct testimony. When these updated dividend yields are incorporated with the growth rates from Sch. DBF 31 through DBF 35 of Dr. Fitzpatrick's direct testimony, the following expected returns result:

Company/Companies	Dividend Yield	Expected Growth	Expected Return
MDU Resources	5.93%	7.00-8.00%	12.93-13.93%
Electric Companies with Beta of .70	7.15	4.00-5.00	11.15-12.15
Electric Utilities with EPS Ranking A, B+, or B	6.30	5.00-5.50	11.30-11.80
Electrics with A or AA Bonds & 0% Nuclear	6.18	5.00-5.50	11.18-11.68
Small Gas & Electronics	6.84	4.00-5.00	10.84-11.84

(MDU Exh. K, Sch. DBF 31 - DBF 35, MDU Late Filed Exh. No. 7)

49. In his rebuttal testimony, Dr. Fitzpatrick concluded that the results cf Mr. Copeland's DCF models are at variance with the analysis of price trends reported in Value Line, which is the source of Mr. Copeland's input data. In support or this conclusion, Dr. Fitzpatrick stated:

> Based on both the January 24, 1986, and the April 25, 1986, data sheets that Mr. Copeland relied upon as inputs to his DCF models, Value Line is projecting Montana-Dakota's stock price to range between $25 and 35 on a post stock split basis during the 1988-90 period -- a level significantly higher than the price level predicted by the Copeland model (MDU Exh. L, p. 4).

50. The Commission closely reviewed the results of Mr. Copeland's model runs but failed to find a "significantly higher" price level for Value Line. The Copeland run that used January 24, 1986, data listed a 1989 price that was below the $25 to $35 Value Line projected price, but at $24.87 on a post stock split basis, a difference of 13 cents can hardly be considered significant. The

computer run for April 25, 1986, data listed the 1989 post stock split price at $29.11, which is well within the Value Line price range.

51. Mr. Copeland's return on equity recommendation was based on his NCGM results for 45 non-nuclear electric utilities. The NCGM model runs resulted in an average return range of 10.7 to 12.3 percent for these 45 companies. Specific results for MDU Resources were in the range of 13.1 to 14.0%.

52. Mr. Copeland reasoned that the results for MDU were higher for two possible reasons: higher investor return requirements for the Company's non-electric activities, or measurement error. In his testimony, Mr. Copeland provided an explanation of measurement error:

> In any sample there are always observations that may be significantly above or below the mean because of measurement problems. Thus, it just may be a coincidence that MDU is higher than the mean, just like it may be a coincidence that Empire District Electric is lower than the mean. The major reason for using sample means at all is to average out distortions that arise from relying on single observations. Just as I doubt that the cost of equity for Empire District is as low as the "point estimate" figures on Schedule 1 would indicate (9.5 to 10.9 percent), so I doubt that the cost of equity for MDU is as high as they indicate (MCC Exh. 4, pp. 14-15).

53. In this proceeding, both witnesses performed DCF analysis of MDU Resources and comparable groups of utilities. In both cases, the witness's DCF results for MDU were higher than for the comparable utilities, and in both cases, the witness's recommended return on equity fell within the return range for the comparable utilities.

54. In performing DCF analysis of MDU Resources, both witnesses were not strictly examining the Company's electric operations. Rather, they analyzed information about the entire company including investor expectations for electric, natural gas, oil, and coal operations. The MDU electric ratepayers should pay a return on equity which compensates stockholders for the risks inherent to the Company's electric operations.

55. After full consideration of the facts presented in this proceeding, the Commission finds a fair range for MDU's cost of equity to be 11.49 to 12.30 percent. The lower bound was taken from the average of the expected returns for Dr. Fitzpatrick's comparable companies listed in Finding

of Fact No. 48. This number is also very close to the 11.50 percent average return expected for Mr. Copeland's comparable group of companies. This average of 11.49 percent represents a reasonable low bound for MDU's return on equity because it reflects information for companies that have similar, but not the same, operations. The upper bound of 12.30 percent was determined by Mr. Copeland's DCF analysis and is, in this Commission's opinion, a fair one. For each of his 45 comparable companies, Mr. Copeland listed several financial and risk characteristics such as: stock ratings, bond ratings, earnings predictability, financial strength, price stability, beta, and safety. These characteristics, when taken together, form a composite ranking of risk. Examination of these composite rankings showed that only 7 of the 45 companies have risks greater than MDU (MCC Exh. 4, Exh. BLC-2, Sch. 4). The Commission also considered the fact that both witnesses' DCF analysis yielded higher expected returns for MDU Resources than for their comparable companies. The Commission believes this information is helpful in determining a fair rate of return on the Company's common equity. The Commission accepts 12.30 percent as MDU's cost of common equity for electric operations.

Rate of Return

56. Based on the findings for long term debt, preferred stock, and common equity in this proceeding, the following capital structure and costs resulting in an 10.655 percent overall rate of return are determined appropriate:

Description	Ratio	Cost	Weighted Cost
First Mort. Bonds	44.491%	10.232%	4.552%
Other L.T. Debt	8.681	8.222	0.714
Preferred Stock	11.280	9.019	1.017
Common Equity	35.548	12.300	4.372
Total	100%		10.655%

PART C

RATE BASE

57. Consistent with previous Commission decisions, both MDU and MCC proposed a 1985 average rate base, adjusted to include certain known and measurable changes. The Commission finds a 1985 average rate base, adjusted for certain known and measurable changes, to be appropriate in this proceeding.

Acquisition Adjustments

58. An acquisition adjustment arises when one utility purchases plant from another utility at a price greater than the net book value of the plant on the sellers books. During 1985, MDU acquired an additional 12 MW increment of the Big Stone generating station from Northwestern Public Service Company (Northwestern). During 1985, and 1986, MDU acquired two additional 5.26 MW increments of the Coyote generating station from Minnesota Power and Light Company (Minnesota Power). The Coyote and Big Stone purchases were both at a price in excess of the net book value on the sellers' books. Therefore, MDU realized acquisition adjustments from each purchase.

59. The Commission has considered the acquisition adjustment issue before. In Order No. 5020b, Docket No. 83.9.68, the Commission noted Montana's original cost statute, 69-3-109, MCA, which states in part:

> The Commission may, in its discretion, investigate and ascertain the value of the property of every public utility actually used and useful for the convenience of the public. The Commission is not bound to accept or use any particular value in determining rates; provided that if any value is used, such value may not exceed the original cost of the property. (emphasis added)

In Order No. 5020b, the Commission determined that the original cost less accumulated depreciation of used and useful property should be allowed in rate base. If a purchase is a necessary, reasonable acquisition made in a arm's-length transaction, the amount of the purchase price in excess of book value (the acquisition adjustment) may be amortized as a recoverable expense over the remaining life of the asset.

60. The Commission continues to find this approach to be wise regulatory policy. The original cost statute precludes ratebasing an amount in excess of the original cost. However, if it is

established that a purchase is 1) necessary, 2) used and useful, 3) negotiated in good faith, 4) reasonable, and 5) the least cost alternative, an acquisition adjustment may be amortized as a recoverable expense over the life of the asset.

61. MCC witness Clark recommended that the Commission follow its prior order and exclude the acquisition adjustments from rate base, but allow the Company to recover the acquisition adjustments by amortizing them over the remaining lives of the Coyote and Big Stone plants. He based his testimony on the Commission's ruling in Order No. 5020b. In addition, Mr. Clark questioned the prices of the Coyote and Big Stone plant increments (MCC Exh. 5, pp. 10-16).

62. In questioning the price paid for Coyote, Mr. Clark referred to a letter from J.F. Rowe of Minnesota Power to Mr. Schuchart of MDU. In that letter, Minnesota Power offered to sell its share of the Coyote station to MDU at net book value (MCC Exh. 5, Exh. [AEC-2]). The Company responded in a letter from Mr. Schuchart to Mr. Rowe that they were interested in purchasing Minnesota Power's share of Coyote at net book value plus an escalation factor (MCC Exh. 5, Exh. [AEC-3]). Mr. Clark surmised that the reason for the escalation factor was the ability to phase the purchase into increments. He stated:

> It is my opinion that MDU was concerned about an excess capacity disallowance if all 21 MW of Coyote was purchased at one time and, rather than risk such an event the Company was willing to pay a premium for the ability to better match the acquisition against the existing load forecasts. The problem now is that while the Company does not appear to be long on capacity, the ratepayers are being asked to pay higher return and depreciation dollars because of the escalated price paid for the first two increments of the Coyote purchase (MCC Exh. 5, p. 11).

63. Concerning the Big Stone purchase, Mr. Clark criticized the lack of support for the agreed upon purchase price. He stated:

> In a packet that was supposed to be "all correspondence to and from the seller," there were apparently <u>no</u> negotiations as to the purchase price. The very first mention of Big Stone at all is in a letter from Northwestern Public Service Company indicating that a consultant had been retained "to certify to the fair value of the Big Stone plant. This was in April 1984. Less than two months later, in June, there is a cover letter from MDU to Otter Tail Power Company enclosing a

> "Letter of Intent executed in triplicate relating to the date and purchase of the Big Stone plant." It would appear that within this two-month period, Northwestern Public Service determined the "fair value" of Big Stone and MDU agreed to purchase at this "fair value" (MCC Exh. 5, p. 12).

64. In addition, Mr. Clark analyzed forecasted surplus and deficit reports for both Northwestern and Minnesota Power, as well as, the entire Midcontinent Area Power Pool (MAPP) system. From this analysis, Mr. Clark reported that Northwestern and Minnesota Power were both forecasting surplus capacity until the mid 1990's (MCC Exh. 5, p. 15). He also indicated that the entire MAPP surplus is forecasted to be 1000 MW in 1995. This surplus is more than double MDU's 493 MW peak load projected for 1995 (MDU Exh. P, Exh. WWK-2).

65. The Company contends that the acquisition adjustments should be allowed in rate base. Mr. Paulsen of MSU rebutted the treatment proposed by Mr. Clark stating: "If this Commission were to accept Mr. Clark's proposal, it would be unfairly and unreasonably penalizing the Company without any basis or reason to do so" (MDU Exh. S, p. 3).

66. In reference to the Big Stone purchase, Mr. Paulsen discussed provisions of the ownership agreement which required Northwestern to offer the plant on an equal basis to all other participants in the unit. Both MDU and Otter Tail Power Company (Otter Tail) wanted to buy the share of Big Stone. For this reason Mr. Paulsen surmised that MDU could not have purchased Big Stone at a cheaper price (MDU Exh. S, p. 22).

67. Mr. Paulsen testified that the Coyote purchase was very attractive due to its location, transmission configuration and established performance record. He stated that the results of an August 1984 generation expansion study showed that extending the purchase over time at an escalating cost would save $5.5 million over the life of the project.

68. The Commission closely examined the Company's generation expansion studies referred to by Mr. Paulsen, particularly the August 1984 study discussed in Finding of Fact No. 67. The August 1984 study was performed to determine the feasibility of acquiring additional Coyote capacity from Minnesota Power. Looking strictly at the results of this study, it would be less costly

to purchase the plant in increments as stated by Mr. Paulsen. Looking at the assumptions that are incorporated into the model, however, reveals an area of serious question:

> The capital investment cost for the additional capacities from the Coyote unit was provided by MP at $1196/KW as of January 1, 1985. The cost estimate was based on MP's depreciated original investment cost for their Coyote ownership. If the purchase occurred after 1984 (after 1985 capacity), MP had proposed the following formula:
>
> Cost in $/KW = (OIC - AD) x (1 + HWI)

where: OIC = Original Investment Cost in $/KW at the date of sale

AD = Accumulated Depreciation
HWI = Change in the Handy-Whitman Index in per unit

(MDU Exh. B, Response to Clark General Information Data Request No. 16, Attachment A.)

The above pricing schedule ignores the fact that in addition to the above factors, MDU is required by the terms of the Coyote purchase agreement to pay "(I) any tax liabilities payable based on statutory rates then in affect on any gain, and (ii) an amount equal to the income taxes payable resulting from inclusion in income of the tax payments referred to in (I) above." (MDU Exh. B, Response to Clark Data Request No. 6 to Kroeber, p. 4.)

69. By not reflecting the income tax liabilities in the calculation, MDU seriously understated the cost of Coyote increments to be purchased at a later date. In fact, the tax impacts included in the September 1985, and May 1986, Coyote purchases were $1,207,700 and $1,408,410 respectively (MDU Exh. B, Response to Data Request No. PSC-136, Attachment C). These tax impacts, which represent Minnesota Power's tax liability on the gain and Minnesota Power's tax liability on the tax liability on the gain, actually represent the vast majority of the total Coyote acquisition adjustments which were $1,337,142 in 1985 and $1,688,432 in 1986 (MDU Exh. A, Statement C, pp. 6-7).

70. The purchase price of the Big Stone increment also contained a provision for MDU to pay the seller's tax liabilities. In response to a Commission staff data request, the Company supplied a work paper which showed the rationale used in determining the Big Stone purchase price

(MDU Exh. B, Response to Data Request PSC-149, Attachment A). The work paper shows very clearly that MDU was required to pay Northwestern's income tax liability resulting from the gain on this sale.

71. The Handy Whitman Index was used in the determination of the price paid for the Coyote increments as stated in Finding of Fact No. 68. The Commission requested MDU to provide an explanation of this index and was supplied with a three page "Foreword" which outlined several important facts about the Handy Whitman Index, including the following:

> The Handy-Whitman Index will furnish a yardstick for the fluctuations in value of property which will be satisfactory for many purposes. In rate cases, when a more exact determination of value is desired, however, the Index must be used carefully. Average prices and cost trends are used to develop the Index, and any direct application of cost trends without checking with actual local experience may not be accepted without controversy. When local experience is compared with the Index and the correlation between the two trends is determined, the result is satisfactory. Costs trended by such a method are used to assist in establishing a rate base (MDU Exh. B, Response to Data Request No. PSC-149, Attachment C, p. 2).

72. During the hearing, Mr. Paulsen was asked if MDU had performed any studies pursuant to the above quote. He responded that he had not performed any studies and was not sure if anyone else at MDU had either (TR p. 363). The Company was then requested to supply any such studies that it had performed in a Late Filed Exhibit. MDU replied that it had performed no such studies (MDU Late Filed Exh. 8).

73. Concerning Mr. Paulsen's testimony that Otter Tail wanted to buy the entire Big Stone plant increment, the Commission could find no such evidence of this statement in the record. In fact, in a letter to Northwestern which was dated July 11, 1984, Otter Tail expressed that the 6.4 percent share it was scheduled to buy "may not be as attractive an offer as we contemplated ..." (MDU Exh. B, Response to Clark Audit Data Request No. 21, Attachment B).

74. In a letter pertaining to the Coyote acquisition adjustment dated May 6, 1986, the Federal Energy Regulatory Commission (FERC) approved MDU's request to amortize the acquisition adjustment over a 28.35 year period. The letter went on to state:

> Approval of your request is granted without prejudice to treatment of the amounts to be amortized should the acquisition adjustment be a matter of consideration in any rate proceeding before this Commission or any state commission which has jurisdiction over your rates. In the event, that any portion of the acquisition adjustment is subsequently disallowed for rate purposes, such portion shall be amortized to Account 425, Miscellaneous Amortization (MDU Exh. B, Response to Al Clark Data Request No. 6 of W.W. Kroeber's Direct Testimony).

75. The "original cost statute," 69-3-109, MCA, referred to in Finding of Fact No. 59 precludes rate base treatment of any acquisition adjustment. In addition to 69-3-109, MCA, other evidence was introduced that supports not allowing rate base treatment of the acquisition adjustments. 1) Coyote could have been purchased at net book value, 2) there is a large surplus of capacity in the MAPP system currently and in the future, 3) both Northwestern and Minnesota Power are also in an excess capacity situation now and in the future, 4) the Company supplied very little correspondence pertaining to the Big Stone purchase, 5) the Company's generation expansion studies were flawed, 6) a large part of the purchase price for both plants results from MDU paying the sellers' income tax liabilities, and 7) the purchase price of Coyote is based on information from the Handy-Whitman Index and the Company has performed no studies to determine the reasonableness of this index with respect to local conditions.

76. There is evidence on the record supporting a finding that the purchase prices MDU paid for Coyote and Big Stone are excessive. The Commission has seriously considered decreasing the amount of the acquisition adjustment to be amortized, but has decided against this adjustment. The evidence, while casting doubt on MDU's purchase price, does not establish a lesser cost.

77. Mr. Clark's proposal allows for the investment to be returned to the stockholders over the useful lives of the Coyote and Big Stone plants and also protects the ratepayer from paying a rate of return on a rate base that is recorded above original cost. The Commission finds this approach to be fair, and therefore, accepts Mr. Clark's proposal resulting in a rate base reduction of $812,447, and a $71,774 increase in expense reflecting the annual amortization of the acquisition adjustments.

Annualization of 1985 Coyote and Big Stone

78. Both MDU and MCC proposed an adjustment to annualize the Coyote and Big Stone purchases. Since these plants were purchased during the course of the test year, the rate base does not fully reflect these plants. The Commission agrees that an adjustment should be made to reflect the full effect of these plants in rate base.

79. The Company included acquisition adjustments in its proposal. Since the Commission excluded these acquisition adjustments from rate base, the annualization adjustment will be examined absent the acquisition adjustments.

80. In light of the above discussion, the Company's proposed adjustment and MCC's proposed adjustment would both result in a rate base increase of $1,242,369. The Commission accepts this annualization adjustment which results in a rate base increase of $1,242,369.

81. In light of this annualization of plant in rate base, there must also be a matching adjustment to annualize depreciation expense and depreciation reserve. Based on the determination of the proper depreciation expense adjustment discussed in Finding of Fact No. 211, the Commission finds a decrease to rate base of $23,254.

1986 Coyote Purchase

82. Both parties agree that this plant should be recognized in rate base as a known and measurable chance which occurred within 12 months of the test year.

83. If the acquisition adjustment is eliminated, the Company's proposed adjustment is equal to the adjustment proposed by MCC - $1,354,950. The Commission accepts this adjustment resulting in a rate base increase of $1,354,950.

84. Again, a matching adjustment to depreciation expense and depreciation reserve must be made. Based or the determination of the proper depreciation expense adjustment discussed in Finding of Fact No. 211, the Commission finds a decrease to rate base of $22,560.

85. Adjustments to reflect additional materials, supplies, and accumulated deferred income taxes resulting from this purchase will be addressed separately in this order.

Accumulated Deferred Taxes

86. As a result of purchasing the 1986 Coyote increment, the Company incurred additional deferred income taxes. Both parties agree that this item represents a rate base decrease. The Company determined that this item decreases rate base by $6,869, while MCC determined that it decreases rate base by $6,140.

87. The proposals differ for two reasons: 1) MDU included the effects of acquisition adjustments in its calculation while MCC did not, and 2) the parties used different depreciation rates in the calculations.

88. Based on the treatment of acquisition adjustments, discussed in Findings of Fact Nos. 58-75, and the income tax adjustment discussed in Finding of Fact No. 222, the Commission determines that this item represents a $5,205 decrease to rate base.

Retired Plants

89. The Company retired several older generating stations during 1985 and 1986.

90. Both MDU and MCC agree that the Beulah and Bismarck plants, which were retired in 1986, have a book value of $306,207. These retirements result in a rate base reduction $306,207.

91. MDU and MCC also agree that substantial costs will result from dismantling all of these retired plants. Removal of the plants will exceed salvage value by more than one million dollars. Both parties agree that this net negative salvage should be placed in rate base and amortized over a five year period.

92. The Company relied on a decommissioning study performed by Stone & Webster Management Consultants for the Beulah and Glendive plants, plus estimates of its own staff about the Williston and Bismarck plants to propose an increase to rate base of $1,130,652.

93. Mr. Clark of MCC also relied on these studies and proposed an increase to rate base of $1,008,776. Mr. Clark's proposal reflected removal of "the 15 percent contingency factors included in the Company's estimated net negative salvage amounts" (MCC Exh. 5, p. 19). Mr. Clark stated that the contingency factors are arbitrary and not known and measurable (MCC Exh. 5, p. 20).

94. The Commission agrees with Mr. Clark's assessment of the contingency factors. As Mr. Clark quoted from the Stone & Webster Plant Decommissioning Study:

> A contingency is included equal to fifteen percent of total estimated cost to cover unknown quantities and increased costs beyond the control of the contractor (MCC Exh. 5, p. 20).

95. Mr. Clark also stated: "I have assumed that such a contingency is included in the estimates for all of the retired plants, not just the two plants included in the Stone & Webster study" (MCC Exh. 5, p. 20).

96. The Commission could find no support in the record for Mr. Clark's assumption. The Commission determines that the amount to be included in rate base is $1,022,057. This figure is derived by using the Company's figures for the Williston and Bismarck plants and Mr. Clark's figures for the Beulah and Glendive plants and includes the effects of an adjustment for accumulated amortization. The calculation also results in an increase in expenses of $227,124 to reflect annual amortization of the net negative salvage.

97. In addition, Mr. Clark reported that, "in South Dakota, the Company has agreed to match actual costs against the estimates and pass on only the actual costs to ratepayers." He recommended similar treatment in Montana (MCC Exh. 5, p. 20).

98. The Commission agrees that the rate payers should provide only the actual decommissioning costs that the Company experiences. Therefore, this issue will be reviewed in the Company's next electric rate proceeding.

Materials and Supplies

99. The Company and MCC proposed two identical adjustments to the level of materials and supplies. The first adjustment increases rate base by $13,214 to reflect a 13 month average balance. The second adjustment increases rate base by $23,761 to reflect additional materials and supplies acquired in the purchase of the 1986 Coyote increment. The Commission accepts both of these adjustments as known and measurable changes, resulting in a rate base increase of $36,975.

Fuel Stores

100. Both MDU and MCC proposed a $12,873 adjustment to reflect additional fuel stores acquired in the purchase of the 1986 Coyote increment. This adjustment is accepted by the Commission and results in a rate base increase of $12,873.

101. The Company also proposed an adjustment to decrease fuel stores by $4,603 reflecting a 13 month average balance and current prices. MCC proposed a similar adjustment that would decrease fuel stores by $89,118. MCC's proposed adjustment differs from that of MDU due to two factors. The first factor, which actually serves to increase fuel stores, is the use of a more current price than used by MDU (MCC Exh. 5, p. 20). The second factor is a reduction to the fuel stores at the Lewis and Clark plant to reflect a permanent reduction at that plant which occurred in 1985 (MCC Exh. 5, p. 20). The Company did not rebut MCC's proposal. The Commission accepts MCC's proposed adjustment resulting in a rate base decrease of $89,118.

102. In addition, Mr. Clark of MCC reasoned that a fuel stores adjustment should be made to provide a complete excess coal profit adjustment (MCC Exh. 5, p. 26). The Commission agrees with Mr. Clark. If no adjustment is made to fuel stores, the Company will be allowed to earn an excess return on that portion of rate base. Based on the Commission's treatment of the coal expense issue (Finding of Fact Nos. 171-172), and the Commission's acceptance of MCC's proposed level of coal tons in fuel stores, the Commission approves a rate base reduction of $51,818 to be proper in this proceeding. The adjustment is calculated below:

Excess Revenue on Sale to MDU	$1,377,000
Divided by Ton Sold to MDU	1,490,519
Coal Price Reduction per Ton	$ .924
Pro Forma Coal Tons in Fuel Stores	171,993.5
Reduction in Value of Coal Stores	$ 158,922
Montana Allocation Factor #2	.32606
Reduction in Montana Fuel Stores	$ 51,818

CWIP Overheads

103. This item refers to overheads on construction projects that were completed during the test year, but due to an accounting lag, were not booked until 1986. MDU and MCC agree that the overheads represent a rate base increase of $21,800. The Commission agrees that it is appropriate to include these overheads in rate base, resulting in rate base increase of $21,800.

Prepayments

104. The Company proposed adjustments to prepaid insurance and prepaid purchased power which represented a rate base decrease of $14,066. MCC proposed a $23,052 rate base decrease for these prepayments. The two proposals differ as a result of using different time periods in the calculation of the adjustment. MDU's adjustment is based on the 13 month period ended December 1986, for prepaid insurance, and the 13 month period ended December 1985, for prepaid purchased power. MCC used the 13 month period ended May 1986, for both insurance and purchased power.

105. MDU's use of 1986 data for prepaid insurance results in using estimated amounts for most of the 13 month period because this case was filed in June, 1986. These estimates, by definition, are not known and measurable. In addition, MDU's use of two different time periods for the prepayments is inconsistent and unacceptable to the Commission. The Company did not rebut MCC's proposal. Because Mr. Clark's proposal is based on more current purchased power information than the Company's proposal, the Commission believes that MCC's adjustment will better reflect changes in prepaid purchased power resulting from the Company's recent resource acquisitions. Also, MCC is consistent in the time periods used to determine its proposed adjustment. Therefore, the Commission accepts MCC's proposal, resulting in a $23,052 rate base reduction.

Unamortized Gain on Reacquired Debt

106. Mr. Clark of MCC proposed to reduce rate base by $350,982 to reflect the unamortized balance of gains the Company realized on reacquired debt. This issue was before the Montana Supreme Court at the time Mr. Clark prepared his testimony. On September 11, 1986, the Supreme Court ruled that in Docket No. 83.9.68 the Commission had properly reduced MDU's rate

base by the amount of unamortized gain on reacquired debt. MDU included an identical adjustment in its rebuttal testimony in compliance with the court's ruling. The Commission accepts the adjustment resulting in a rate base decrease of $350,982.

Unamortized Deferred Depreciation & Additional AFUDC - Coyote

107. Both MDU and MCC agree that this issue represents a rate base increase of $1,006,294. In Order No. 5036a of Docket No. 83.9.68, the Commission found that AFUDC occurring more than 12 months after the test year should be not be included in rate base until the Company's next rate application. Pursuant to that order, the Commission finds a $1,006,294 rate base increase to be appropriate in this proceeding. This amount includes the effects of an adjustment to accumulated amortization. Appropriately, an adjustment to increase expenses must also be made to reflect the amortization expense.

Accumulated Reserve on CWIP in Service

108. This adjustment provides for one year's depreciation on construction completed during 1985. MDU proposes a rate base decrease of $2,830 while MCC proposes a decrease of $2,635. This minor difference is attributable to the fact that the parties did not use the same depreciation rates. Based on the depreciation expense adjustment discussed in Finding of Fact No. 211, the Commission determines that this item results in a $2,667 decrease to rate base.

Property Sold in 1985

109. The Company sold approximately two miles of transmission facilities to Capital Electric Cooperative during February 1986. This property had a book value of $250,464 at the time of the sale (MDU Exh. B, Response to Data Request No. PSC-158, Part f). During the hearing, Mr. Ball, of MDU, was asked if the sale was a known and measurable change in rate base within 12 months of the test year. He responded that it would be by definition (TR p. 291).

110. Because this sale results in a known and measurable change in the Company's rate base, the Commission finds an adjustment is in order. Using the approved depreciation rates for

transmission plant, the Commission determines the average balance of this plant was $253,487 during the 1985 test year. This amount becomes $62,682 when allocated to Montana per Factor No. 34, Transmission Plant, which is listed on Rule 38.5.176, Statement L, Part B, p. 3 of 4. In light of this discussion, the Commission finds a reduction to rate base of $62,682 to be appropriate in this proceeding.

Annual Depreciation Reserve

111. MCC included an adjustment to depreciation reserve in conjunction with an annual depreciation expense adjustment. The Company also proposed an annual depreciation expense adjustment, but did not include a corresponding adjustment to the depreciation reserve.

112. When an adjustment is made to depreciation expense, it is proper from a matching standpoint to make a corresponding adjustment to depreciation reserve in the rate base. Based on the approved depreciation expense adjustment discussed in Finding of Fact No. 209, the Commission finds a rate base increase of $75,381 to be appropriate in this proceeding.

Total Rate Base

113. As a result of the approved adjustments described above, the Commission finds the proper amount of total 1985 average rate base adjusted for known and measurable changes to be $66,972,346 in this proceeding.

PART D

REVENUES, EXPENSES, AND REVENUE REQUIREMENT

114. Mr. Ball, of MDU, sponsored exhibits and testimony that supported the revenue increase request of $4,549,702. The request was based on an overall rate of return of 11.174 percent. Mr. Ball indicated that the Company utilized a 1985 historical test period as a basis for its filing and made various 1986 adjustments. Mr. Ball concluded that, based on the test period ended December 31, 1985, the Company would require additional revenues of $4,549,702 in order to earn an overall return of 11.174 percent (MDU Exh. Q, pp. 19-20).

115. Several factors occurred subsequent to the Company's filing which directly impacted this proceeding (MDU Exh. R, pp. 7-8). Due to these factors, Mr. Ball decreased the Company's request by $503,288, resulting in a revised revenue increase request of $4,048,164 (MDU Exh. R, p. 8).

116. Mr. Clark, expert witness for MCC, presented testimony and exhibits on the cost of service and the proper rate base. Mr. Clark also utilized an average 1985 test period, adjusted for certain known and measurable changes. He prepared a series of schedules and presented related testimony that culminated with the change in revenues required to produce the 10.363 percent rate of return recommended by Mr. Copeland. Mr. Clark concluded that, based on the 1985 average test year, the Company required additional revenues of $839,785.

117. Two events that affect the outcome of this proceeding occurred after Mr. Clark filed testimony. First, the rate of the new Montana PSC Tax became known. Second, Mr. Clark discovered a computational error in one of his adjustments subsequent to filing testimony in this proceeding. As a result, he filed supplemental testimony and exhibits outlining a revised increase in revenues of $135,870 (MCC Exh. 6, p. 4).

Operating Revenues

MDU Proposed Adjustment

118. In its filing, MDU proposed to decrease revenues by $18,127 to reflect the elimination of KVAR charges, the change in Optional Time-of-Day General Electric Service Rate 26 (Time-of-Day), and minor billing adjustments (MDU Exh. Q, p. 8).

119. This proposal will be broken down into three separate parts for analysis in this order. The three proposed adjustments are: 1) elimination of KVAR charges - a revenue decrease of $21,949, 2) Time-of-Day rate change - a revenue increase of $2,203, and 3) billing adjustments - a revenue increase of $1,619.

120. The first item, KVAR charges, represents a penalty assessed by the Company in accordance with the Power Factor Clause stated in the currently effective electric rate tariffs. The

Company believes these charges should not be considered as revenue because they represent a nonrecurring penalty charge to the specific ratepayer.

121. In addition, the Company has requested an increase in the KVAR charge from $1 to $1.75. Mr. Ball testified that because of the increased charge "customers will take a much harder look at installing the equipment to bring their power factors in line" (TR p. 299).

122. The result of the increased KVAR charge cannot be accurately measured until it actually occurs. For instance, if the increased charge causes KVAR occurrences to drop by 25 percent, the resulting revenue impact will actually be an increase of $6,859. The actual occurrences must decrease by more than 43 percent for the total KVAR revenues to drop below the 1985 level. For the Commission to eliminate KVAR charges from revenues, there must be substantial evidence that shows these charges will not recur.

123. According to Mr. Ball, the present KVAR charge is already more expensive than corrective action would be for those customers that incur the charge (TR p. 287). In spite of this fact, KVAR charges have provided a relatively constant flow of revenues from 1980 through the first six months of 1986 (TR p. 288). Indeed, the Company has received $10,600 from the KVAR charges during 1986. Annualized, that figure would be $21,200, which is very similar to the annual revenues from this charge over the 1980 through 1985 time period (TR p. 288). Exclusion of such revenues would be improper because they reflect constant annual revenues paid by Montana electric customers. MDU's proposed adjustment to remove KVAR revenues is disallowed.

124. The other two portions of the Company's adjustment, Time-of-Day rate change and billing adjustments, merely help to reflect the Company's revenues under the present rate structures. For instance, the Time-of-Day rate was changed on September 26, 1985. If this change had occurred on January 1, 1985, the Company would have received an additional $2,203 in revenues for the year. The billing adjustment recognizes that billing errors were made during the year and adjusts revenues to reflect the fact that the Company would have received an additional $1,619 in revenues if the billing errors had not occurred. The Commission accepts these adjustments, thereby increasing per books sales revenues by $3,822.

Late Payment Charges

125. MDU reported late payment charges of $11,228 for Montana in 1985. When questioned about the treatment of these charges, Mr. Ball testified that they are recorded below the line (TR p. 192). As such, these charges were not recognized as revenues in the Company's filing.

126. Late payment charges were approved by this Commission to serve two purposes: 1) provide an incentive for ratepayers to keep their utility bills current, and 2) help offset the costs associated with collecting delinquent accounts.

127. The Commission notes with interest that Great Falls Gas Company included late payment charge revenues as an adjustment in Docket No. 85.7.26. The Commission accepted that adjustment, thus including the late payment charge revenues in the determination of Great Falls Gas Company's revenue requirement (Docket No. 85.7.26, Order No. 5153a p. 13).

128. All of the expenses associated with customer accounts are included in the determination of revenue requirements in this proceeding. If ratepayers are not allowed the benefits of the late payment charges, then there is no offset to the costs associated with collecting delinquent accounts. Thus, one of the purposes of the late payment charge is violated. Since the ratepayers are paying these costs, this Commission believes they should be the ones to benefit from revenues generated by the late payment charge, not the stockholders. The Commission finds that late payment charges must be included as revenue. Therefore, a revenue increase of $11,228 is determined to be appropriate in this proceeding.

Gain on Sale of Properties

129. During 1985 and 1986, the Company sold several electric utility rate base properties at a gain of $29,949 (MDU Exh. B, Response to Data Request No. PSC-158). Mr. Ball testified that these gains were booked below the line (TR pp. 290-291). As such, these gains were not recognized as revenue in the Company's filing. The Commission is now faced with the proper treatment of these gains.

130. The Commission has faced this issue before. In Order No. 5194a, Docket No. 86.3.7, the Commission used two principles to determine treatment of Butte Water Company's gain on the

sale of property. The two principles are: 1) right to gain follows risk of loss, and 2) economic benefits follow economic burdens.

131. Stock holders have been compensated for their risk through the rate of return granted on rate base. Additionally, when an asset is retired at a loss, the ratepayer often absorbs that loss through increased rates. A prime example of such a loss is included in this proceeding. The Company retired several older production plants during 1985 and 1986. As a result of those retirements, the Company is incurring a cost in excess of $1 million dollars for net negative salvage. The Commission is allowing these net negative salvage costs to be recovered from ratepayers over a five year period. The net negative salvage costs are nothing more than losses incurred by the Company to retire these older plants. If the Commission were to have ratepayers pay for the losses while not allowing them to benefit from the gains, an unfair and inequitable treatment would result.

132. The ratepayers paid for all the expenses associated with the properties while in service (TR pp. 291-292). Because the ratepayers shouldered the economic burden, they are now entitled to the economic benefit.

133. From these perspectives, the Commission determines that the gains are properly includable as revenue in this proceeding. Based on the Company's allocation of "Other Operating Revenues", the Commission finds that these gains result in an increase in revenues of $8,006 attributable to Montana electric operations.

Total Revenues

134. The Commission determines that, based on the above discussions concerning operation revenues, the resulting approved pro forma operating revenues are $31,920,994.

Expenses

AVS II

135. Originally, the Company proposed a $1,763,438 adjustment to fuel and purchased power expenses to reflect significant changes in its resource mix. The Company's adjustment shows the step by step changes in fuel and purchased power costs that result from the 1985 Big Stone and

Coyote purchases, the 1986 Coyote purchase, and the estimated costs of the 1986 AVS II firm power purchase. MDU updated its proposed adjustment to reflect actual AVS II costs in place of estimates included in the original proposal (MDU Exh. R, pp. 7-8). The Company's updated adjustment is $1,518,142.

136. Mr. Clark originally proposed an $817,557 adjustment on behalf of the MCC. Subsequently, Mr. Clark discovered that he had calculated his proposed adjustment incorrectly by double counting fuel and purchased power expenses by $774,347 (MCC Exh. 6, p. 3). The net result of Mr. Clark's adjustment is an increase to fuel and purchased power expenses of $43,210. Mr. Clark's proposal recognizes the effects of the 1985 Big Stone and Coyote purchases, and the 1986 Coyote purchase. With respect to the AVS II power purchase, Mr. Clark substituted MAPP Sch. H and Sch. E power purchases.

137. In analyzing the effects of the AVS II power purchase, Mr. Clark testified that the Company does not have excess capacity but does have excess energy. He based this on the fact that generation of electricity at the Company's other power plants dropped by 88,750 megawatt hours (MWh) when AVS II was added to the Company's resource mix (MCC Exh. 5, p. 32).

138. On a variable cost basis, AVS II energy is less expensive than energy from any of the other MDU generating stations. Mr. Clark points out, however, that the total cost for AVS II energy is $48.84/MWh under the Company's first year capacity factor (based on the Company's original AVS II cost estimates). He goes on to state "Thus, to a great degree, MDU is asking Montana ratepayers to replace energy costing from $13.52 to $24.79 per MWh with energy costing $48.84/MWh or up to 261 percent as much" (MCC Exh. 5, p. 33).

137. Mr. Clark stated that "there is an abundance of readily available Sch. H power and energy and Sch. E energy for MDU to purchase" (MCC Exh. 5, p. 35). He also believes that his recommendation does recognize the Company's need to make long term power plans (MCC Exh. 5, p. 36).

139. Mr. Paulsen of MDU testified that Mr. Clark's proposal could not have been realistically utilized by MDU. He stated that Mr. Clark' proposal "combines the low capital costs associated with the turbine with the low fuel cost associated with base load capacity" (MDU Exh.

S, p. 7). Mr. Paulsen explained that MAPP Sch. H purchases are limited to a low load factor of only 20 percent. Mr. Paulsen also explained that MAPP Sch. E energy is not reliable because the selling utility can cancel the sale upon a one day's notice (MDU Exh. S, p. 8).

140. Mr. Paulsen also found fault with Mr. Clark's cost comparisons between AVS II and the Company's other generating stations. He points out that the $48.84/MWh cost for AVS II includes depreciation and other capital costs while costs of the other plants only include operation and maintenance costs (MDU Exh. S, p. 13). Therefore, he feels that Mr. Clark's comparison is incorrect.

141. The capital costs associated with the Company's other power plants are essentially sunk costs. This means that regardless of the amount of energy produced, the capital costs will still be charged to ratepayers. Since ratepayers are required to pay these costs for the remaining lives of MDU's other power plants, these costs are not relevant. The capital costs included in the AVS II demand charge are relevant if the power was purchased to displace existing energy production. That was not the reason MDU acquired the AVS II resource. The AVS II firm power purchase was acquired by the Company as a reliable resource to meet present and future load requirements. The drop in energy production at the Company's other plants is only a result of AVS II variable costs being less costly than the variable costs of the other generating stations.

142. Additionally, the Commission found a severe deficiency in Mr. Clark 's proposal. That deficiency pertains to his treatment of Sch. E purchases. The MAPP agreement that is on file with this Commission specifically defines economy energy as:

> ...energy which one Participant may deliver under Service Schedule "E" to another Participant for the purpose of replacing more expensive energy.

143. This means that the Company must reduce its generation of energy by an amount equal to the energy purchased under MAPP Sch. E. Mr. Clark's proposal treats Sch. E energy as an additional long term energy source for MDU, when in reality it is no more than a cost reducing mechanism which cannot be acquired without first having other energy sources that can be forgone. The Commission finds that MCC's proposal is simply not feasible. The Company's proposal to

include the costs associated with the AVS II firm power purchase is accepted resulting in a $1,518,412 increase to the per books fuel and purchased power expenses.

Captive Coal

144. The Knife River Coal Company, a wholly owned subsidiary of MDU Resources, provides coal for the Heskett, Lewis and Clark, Big Stone and Coyote generating plants. MDU owns 100% of Heskett and Lewis and Clark and contracts with Knife River for these plants' coal supplies. MDU owns 22.7 percent of Big Stone and 22.5 percent of Coyote. A consortium of utilities, including MDU, entered into coal supply contracts with Knife River for the Big Stone and Coyote plants. These contracts specify the prices MDU pays for coal, and it is these prices that MDU seeks to pass on to ratepayers as its coal expense.

145. In captive coal situations an affiliate of the utility supplies the utility's coal. Concerning the purchase of coal from a subsidiary, the Montana Supreme Court has held:

> A function of the PSC, in fulfilling its duty to supervise and regulate the operations of MDU as an electric utility, is to see that MDU's rates are just and nondiscriminatory. Section 69-3-330, MCA. In complying with this obligation, it follows that the PSC must scrutinize and review the operating expenses of MDU to prevent unreasonable operating costs from being passed on to the customer. When one of the expenses submitted by MDU is caused by transactions with a subsidiary company, the scrutiny applied by the PSC must be all the more intense. Montana-Dakota Utilities Co. v. Bollinger, 632 P.2d 1086, 1089 (1981).

As a result of the affiliated relationship between MDU and Knife River, the Commission must carefully scrutinize the impact on electric rates of all MDU coal purchases from Knife River. The Commission's concern is whether expenses that MDU ratepayers are charged are reasonable. The Commission notes that MDU is a participating owner, not the full owner, in the Big Stone and Coyote plants. However, regardless of MDU's position that Knife River supplies these plants with fuel at a price negotiated in an arms-length transaction agreed to by MDU and its generating partners, the Commission is required to carefully scrutinize this transaction.

146. In 1985 Knife River earned over 18 percent on year-end stockholder equity. (MDU Exh. B, Response to Al Clark General Data Request No. 22, Attachment A.) MDU Resources, Inc.'s stockholders earn this rate of return by selling coal to the electric ratepayers. As stated by Mr. Copeland of MCC:

> There is always the possibility that the primary motivation for dealing with an affiliate is to exploit the opportunity to earn a higher rate of return than could be earned otherwise (MCC Exh. 4, p. 32).

147. MDU and MCC have again presented the Commission with two methods of determining if MDU's coal expense is reasonable. Mr. Copeland, testifying on behalf of MCC, presented a rate of return approach that evaluated Knife River's rate of return on coal sales between MDU and Knife River. Mr. Wilson, through rebuttal testimony, supported MDU's market price approach that compared the price paid by the utility for its coal supplies with prices paid by other buyers.

148. In support of market price analysis, MDU evaluated Knife River's financial performance, including the reasonableness of the prices it charges MDU. Mr. Wilson stated, "I conclude that Knife River Coal Mining Company operates in a very competitive business and the prices it charges MDU for coal are reasonable and do not result in unreasonable profits" (MDU Exh. O, p. 2).

149. Mr. Wilson testified that there is a very competitive market for lignite coal in the general area served by MDU (Exh. O, p. 224). He listed five companies that produce in excess of one million tons of lignite coal from mines in North Dakota. Mr. Wilson determined that these five companies' lignite operations are generally comparable with Knife River in production capacities, mining methods, average specifications of the coal they produce, the competitive markets they serve, mining regulations, and quite likely, the general range of their operating costs (MDU Exh. O, p. 3).

150. Mr. Wilson presented a comparison of coal prices at North Dakota and Montana lignite coal mines. These prices range from \$6.87/ton at Baukol-Noonan's Center Mine to \$13.93/ton at Knife River's Savage Mine (MDU Exh. O, Exh. WWW-4).

151. Mr. Wilson found one of these companies, Baukol-Noonan Inc., to be very comparable with Knife River. He stated:

> Both companies operate only as producers of coal in the North Dakota-Montana lignite basin, mining the same or comparable seams using similar mining equipment and methods to recover coals of comparable qualities and heat content (MDU Exh. O, p. 5).

Mr. Wilson considered the most significant difference between the two to be a provision of the Baukol-Noonan coal prices that requires utilities to provide all of the electric power needed to operate the mine at no cost, with the utility also crushing the coal. Knife River pays its electrical and crushing costs and these costs are reflected in the price of its coal (MDU Exh. O, p. 25). He later stated:

> There is no way to determine the price component of the power supply and crushing provisions of the Baukol-Noonan contract, except to note that Baukol-Noonan enjoys a slightly higher rate of return on average equity than does Knife River (MDU Exh. O p. 25).

152. MCC witness, Basil Copeland, testified that the market price approach has problems that render it unsuitable for evaluating utility transactions with coal affiliates (MCC Exh. 4, p. 32). Coal is not a homogeneous commodity due to differences in heat content, sulfur, ash, etc. In addition, transportation can significantly affect the price paid for coal. Mr. Copeland further testified that coal transactions with affiliated companies are nothing more than a form of vertical integration, which is a non-market method of allocating resources (MCC Exh. 4, pp. 33-35). He continued:

> When resources are not being allocated by market forces, there is no basis for using a market standard to evaluate the reasonableness of such transactions. The withdrawal of resource allocation from exposure to market forces (which is what vertical integration accomplishes) is justifiable only if it leads to a lower cost of production. Thus, the transfer price at which transactions take place among vertically integrated affiliates should always be below the price that would be derived using a market standard (MCC Exh. 4, p. 35).

153. Mr. Copeland stated that most coal contracts do not actually contain a specified price. The contracts usually contain a formula to determine the price based on coal quality and production costs, with a provision beyond that to recover an agreed upon level of profit. He testified that the rate of return standard is basically the same standard used to determine the ultimate cost of coal; cost plus

profit (MCC Exh. 4, pp. 35-36). Examination of the coal contracts between MDU and Knife River establishes that Mr. Copeland's testimony is correct. The Big Stone contract, for instance, specifies that Knife River's return on sales shall be in the range of 15 to 22 percent after income taxes (TR pp. 235-238). The Heskett and Coyote contracts also specify return provisions of 15 to 22 percent (MDU Exh. B, Attachment A of Response to Rebuttal Data Request No. MCC-43). These contracts show that MDU's cost of coal is determined based on a preset level of profit.

154. MCC cross-examined Mr. Wilson of MDU about the financial statements of Knife River and Baukol-Noonan, the company Mr. Wilson testified is comparable to Knife River. Mr. Wilson believes the cost of electricity must reflect the difference in price of Baukol-Noonan's seven dollars per ton coal cost and Knife River's eleven dollars per ton coal cost (TR p. 232). A review of the actual 1985 electricity costs experienced by Knife River reveals that on a per ton basis, the electricity costs at the Beulah and Gascoyne mines were 4.9 and 10.9 cents respectively (TR p. 234). This information suggests that other factors contribute to the approximately four dollar per ton price differential. Additionally, it throws doubt on the validity of Mr. Wilson's statements about the comparability of Knife River's operating costs with those of other lignite mines in the area.

155. Further questioning showed that Baukol-Noonan earned 7.4 percent return on its coal sales (TR p. 240), compared to Knife River's guaranteed 15 to 22 percent return on coal sales to MDU. This evidence clearly indicates that the profit component in the price Knife River charges MDU for coal must be significantly higher than Baukol-Noonan's profit included in its coal price.

156. The validity of MDU's market price approach hinges on the assumption that a competitive market exists for lignite coal in the region. As stated above, Mr. Wilson testified that he believes "this area constitutes a very competitive market for lignite coal and that market-driven prices can be used to substantiate the fairness and reasonableness of Knife River's prices" (Exh. O, p. 24). However, when asked in discovery whether he had considered any of the following factors in determining that the area constitutes a very competitive market:

the number of suppliers
the number of customers
the number and frequency of transactions
price elasticity of demand
price elasticity of supply

cross-price elasticity of demand
cross-price elasticity of supply
total market demand
total market supply
total supply of alternatives
sunk costs
replacement costs
opportunity costs
transaction costs
variable cost
transportation costs
concentration ratios
lead time
supply and demand conditions in final product markets.

Mr. Wilson replied:

> That is my opinion, drawn from the facts, which I have set forth in my pre-filed testimony. I do not believe that the existence or non-existence of competition can be mechanically established by objective criteria. Therefore, I have no opinion as to the reliability or even the desirability the criteria listed (MDU Exh. B, Response to MCC Data Request 7).

157. As previously stated, the coal prices presented by Mr. Wilson ranged from $6.87/ton to $13.93/ton. The highest price in this range is more than twice as much as the lowest price, reflecting an extremely wide range of prices in the region. The Commission has thoroughly considered MDU's evidence in support of a market price approach to determine the reasonableness of the Company's coal expense but the evidence presented to this Commission by MCC shows that MDU's coal expenses cannot be established by the price paid by other coal buyers. The price is dependent on the operating costs (including profit) of each specific mining operation. These operating costs can vary substantially even within one company. For example, a comparison of the 1985 overburden stripping expenses on a per ton basis at Knife River's Savage, Beulah, and Gascoyne Mines clearly shows:

Beulah	Gascoyne	Savage

$1.781	$0.392	$1.409

158. As stated above, by contract, Knife River is guaranteed a return on sales of between 15 and 29 percent on its coal sales to MDU. Because the contracts guarantee that MDU will pay all of the costs to produce the coal, the Commission believes all of the costs to produce the coal, the Commission believes many of Knife River's risks are effectively passed on to the electric utility.

159. It is widely accepted that a reasonable return on investment depends in part on the level of risk faced by a company. This means that as risk increases so does the return the investor requires. In direct testimony, Mr. Copeland stated that the vertical integration between MDU and Knife River reduces risk and uncertainty for both parties (MCC Exh. 4, p. 37).

160. Another aspect of Knife River's lower risk can be seen in the composition of its capital structure. Because debt has first right to the revenues and assets of a company, an increase in debt represents an increase in risk to the equity investor. Most companies have some level of long term debt in their capital structure, but Knife River does not. Its capital structure is 100 percent equity (MDU Exh. B, Attachment A of Response to Al Clark General Data Request No. 22).

161. MCC witness, Basil Copeland, performed several studies indicating that a 12.5 percent return is proper for coal transactions between MDU and Knife River (MCC Exh. 4, pp. 43-44). First, Mr. Copeland examined recent and projected rates of return for the six companies classified as coal companies by the Value Line Investment Survey (Value Line). Second, he estimated the rate of return for MDU electric operations to be 11.5 percent, and that a 100 basis point upward allowance for Knife River would imply 12.5 percent. Third, Mr. Copeland examined the profit rates earned by companies engaged in mining and crude oil production.

162. Mr. Wilson rebutted Mr. Copeland's study of the six Value Line companies. He presented an in depth analysis of each company in the group and concluded that they were not an appropriate sample for evaluating of the independent coal industry's profitability (MDU Exh. O, pp. 10-20). Mr. Wilson found these companies to be highly diversified and, therefore, not compara-
most of the coal produced by these six companies is mined from deep mines with much higher unit csts than the coal produced at Knife River's shallow surface mines (MDU Exh. O, p. 9).

163. Mr. Wilson believes that the six Value Line companies used by Mr. Copeland are not comparable to Knife River because these companies are diversified. Mr. Wilson testified that Baukol-Noonan could be compared with Knife River. During the hearing, however, it was discovered that Baukol-Noonan also had significant levels of income from sources other than coal sales. To be specific, over $1 million dollars, or 38 percent of Baukol-Noonan's 1985 income was from non-coal sources (TR p. 241). Even Knife River derived almost $2 million dollars, or nearly 12 percent of its 1985 income from non-coal sources (TR p. 243). In short, the Commission believes that diversification, in and of itself, does not eliminate a company from comparability with Knife River. As stated above, even Knife River had income from sources other than coal sales.

164. Mr. Copeland's use of the six Value Line coal companies to test the reasonableness of a captive coa1 company's profits provides some useful guidelines for determining a reasonable level of profitability for transactions between MDU and Knife River, and thus, a reasonable coal expense. Several of these companies, however, have experienced difficult financial times due primarily to the reduced demand for the metallurgical grade coal that some of them produce (MDU Exh. O, pp. 10-20). Another comparison problem is that with such a small group of companies, the operating results from one or two of the companies may have a significant impact on the average results of the group .

165. In order to help alleviate some of these concerns, the Commission included Baukol-Noonan's equity return figures from Mr. Wilson's Exhibit WWW-2 with the return figures from Mr. Copeland's Value Line companies. The results show a 12.1 percent average return in 1984 and 12.0 percent average return in 1985 (1985 results were provided in MCC late Filed Exh. 1). Additionally, forecasted returns on book equity and expected market returns for Mr. Copeland's comparable companies averaged 12.2 and 13.4 percent respectively, with median figures of 14.0 percent and 12.2 percent (MCC Exh. 4, Exh. BLC-2, Sch. 6). Expected returns for Baukol-Noonan were not available for examination.

166. Because of the difficulties inherent in finding truly comparable coal companies with which profit comparisons can be made, the Commission finds it reasonable to look at other areas of the economy for profitability figures. Mr. Copeland presented evidence showing that other sectors

of the economy earned 13.5 percent in 1984 and 11.5 percent in 1985 (MCC Exh. 4, Exh. BLC-2, Sch. 8). Of more significance to this Commission is the profitability of corporations in the Mining, Crude Oil-Production group. This group, according to Mr. Copeland, "is most comparable to the industry in which Knife River operates" (MCC Exh. 4, p. 44). For the 1975-1985 time frame when inflation and required rates of return were high (MCC Exh. 4, p. 44), these companies earned an average of 14.66 percent return on equity. The equity returns experienced by these companies were 13.8 percent in 1984 and 11.5 percent in 1985.

167. Again for comparison purposes, the Commission combined the equity figures of Baukol-Noonan (MDU Exh. O, Exh. WWK-2) with the results of these companies. The resulting average return on equity was 14.2 percent in 1984 and 11.8 percent in 1985.

168. Mr. Copeland proposed a 100 basis point difference between a fair return for MDU's electric operations and a fair return for Knife River's operations (Finding of Fact No. 161). The Commission agrees with Mr. Copeland that Knife River's coal mining business is more risky than MDU's electric operations, but it does not agree that the calculation of a reasonable price for MDU to pay for Knife River coal can be based on the return granted to MDU electric operations. MDU's reasonable expense for coal will be established on the basis of Knife River's return on coal sales to MDU in comparison to companies similar to Knife River, not in comparison to the electric utility's rate of return.

169. In determining a reasonable price for coal transactions between Knife River and MDU, the Commission took into account many factors. First, 1984 and 1985 returns for coal companies, including Baukol-Noonan, were 12.1 and 12.0 percent (Finding of Fact No. 165). Second, forecasted returns that were available for these companies range between 12.2 and 14.0 percent (MCC Exh. 4, Exh. BLC-2, Sch. 6). Third, returns for the mining, crude oil-production industry, including Baukol-Noonan, were 14.2 percent in 1984 and 11.8 percent in 1985 (Finding of Fact No. 167). This information clearly suggests to the Commission that a fair return on equity for coal transactions is in the range of 12 to 14 percent. The Commission finds the midpoint of that range, or 13 percent, to be appropriate in this proceeding. This figure is higher than the 1985 equity return figures for the coal companies (12.0 percent), mining and crude oil-production companies

(11.8 percent), and all industries as a whole (11.5 percent), as well as MCC's recommended return of 12.5 percent.

170. The Commission believes that the most reasonable approach to calculating Knife River's return is to look at the actual results of operation. Because Knife River is an unregulated enterprise, it is improper to apply regulated industry adjustments to its financial statements. Knife River's net income for 1985 was $12,057,329 and its year end equity was $66,450,394. The resulting 1985 return on equity, on a year end basis, is 18.14 percent, considerably higher than the 13 percent return discussed above.

171. Knife River should not be able to charge a coal price to MDU, to be paid by MDU's ratepayers, that reflects profits far above those of other companies in the same industry, many of which do not enjoy the risk reducing characteristics enjoyed by Knife River. In summary, the Commission finds that the above analysis indicates MDU's reported coal expense is unreasonable and that an adjustment to MDU's coal expense is proper in this proceeding. Based on all of the information presented, the Commission finds that the coal expenses claimed by MDU that reflect an approximate 18 percent profit level for Knife River in 1985 are excessive and should be reduced.

172. The captive coal adjustment in this proceeding is, therefore, calculated as follows:

		(000)
Knife River 1985 Year-End Equity		$ 66,450
Equity Return at 13%	8,639	
Actual Knife River 1985 Net Income		12,057

Excess Knife River Net Income		3,418
Tax Multiplier (1)		x 1.3538

Total Excess Revenue		4,627
MDU % Knife River Sales (2)		x .2976

Excess Revenue on Sales to MDU		1,377
Montana Allocation Factor #2		x .32606

Approved Level of Adjustment		449

(1) Actual Knife River Taxes + Net Income Divided by Net Income Equals the Tax Multiplier.
(2) Knife River Sales to MDU Divided by Total Knife River Sales.

Labor Expense

173. In his direct testimony, Mr. Ball of MDU proposed an adjustment to decrease Labor expenses by $95,016. His proposal was based on the test year level of employees and adjusted to reflect reduced labor expenses associated with retired plants, and increased labor expenses associated with wage increases.

174. During his rebuttal testimony, Mr. Ball revised his proposed adjustment resulting in a $339,290 proposed decrease to 1985 labor expenses. Mr. Ball's revised proposal is arrived at by using the number of employees as of July 1986. It recognizes the estimated effects of a newly instituted early retirement plan and an actual 2.4 percent union wage increase, which the Company originally estimated to be a 3.8 percent wage increase. Mr. Ball's revised proposal would decrease 1985 labor expenses by $339,290. Mr. Ball says the early retirement program also significantly affects the pension costs for MDU, noting that this decrease cannot be considered separately from a corresponding increase in fringe benefit costs (MDU Exh. R, p. 5).

175. Mr. Clark of MCC proposed a $136,169 decrease to labor expenses. His proposal starts with the test year level of labor expenses, deletes labor associated with the retired plants, adds a full years wage increase for non-union labor, and adds four months of an estimated 3.8 percent union wage increase, which was scheduled to occur in September 1986.

176. In a recent MDU natural gas proceeding, Docket No. 85.7.30, the Commission was faced with a similar situation. In that proceeding the Commission was presented with a post test year level of employees (as is presented by MDU in this proceeding), and a failure to reflect the full effects of a wage increase (as is presented by MCC in this proceeding). Order No. 5160a addressed these two issues:

> Concerning the first factor, level of employees, Mr. Clark based his proposal on his analysis which showed that the employee levels have been decreasing since the end of the test period. He stated that his

> proposal is probably conservative given the August, 1985, level of employees. This type of adjustment has repeatedly been denied by the Commission primarily for matching reasons. The test period is used as the basis for determining proper levels of expense, and tying the test year level of employees with the costs incurred during the same time frame seems appropriate. Recognizing wage increases for the same level of employees beyond the end of the test year as known and measurable changes is also appropriate as such recognition does not cause any matching problems (Docket No. 85.7.30, Order No. 5160a, Finding of Fact No. 87).

177. The Commission finds that MDU's revised adjustment cannot be used because it is based on a post test year level of employees, which this Commission has repeatedly found to cause matching problems. The Commission accepts MCC's proposal subject to two adjustments. The first adjustment is to update the union wage increase used by Mr. Clark from 3.8 percent to 2.4 percent. This change reflects that Mr. Clark used an estimated 3.8 percent increase to union wages as supplied by MDU. Mr. Ball stated that the actual level of this increase is now known to be 2.4 percent (MDU Exh. B, Response to Rebuttal Data Request No. MCC-55). The second adjustment reflects one full years' recognition of this 2.4 percent increase in lieu of the four months recognized by Mr. Clark. The Commission finds that including only four months of the increase does not fully reflect the effects of this known and measurable change. In light of these adjustments, the Commission finds a $116,682 decrease to labor expenses to be proper in this proceeding.

Payroll Taxes

178. The above labor adjustment results in total Montana allocated labor costs of $4,527,801. Based on the current tax rate of 7.15 percent, pro forma FICA taxes would be $323,738. The Company only booked $307,433 (MDU Exh. B, Rule 38.5.176, Statement L, Part A, p. 21) for Montana FICA tax during 1985. In order to match the appropriate FICA tax level with the accepted labor cost level, the Commission finds a $16,305 FICA tax increase to be proper in this proceeding.

Fringe Benefits

179. The Company originally proposed a $41,483 decrease to fringe benefits expense. This proposal was based on forecasted 1986 fringe benefits expenses. Mr. Ball of MDU revised this adjustment in his rebuttal testimony to reflect fringe benefits expenses for the 12 months ended August, 1986, including the expected effects of the Company's early retirement program. The Company's revised proposal would result in a $148,078 increase in fringe benefits expense.

180. Mr. Clark proposed an adjustment to decrease fringe benefits expenses by $44,606. His proposal reflects the Company's fringe benefits expenses for the 12 months ended April, 1986.

181. The Company disagreed with Mr. Clark's proposal because there were negative adjustments to fringe benefits expenses in two months of his chosen time period. Those two months were July and December of 1985 (TR pp. 346-347). During the hearing, Mr. Ball was asked if group insurance expense of $396,197 for October 1985 also might contain an accounting adjustment. He responded that an adjustment might also have occurred that month (TR p. 347). The Commission agrees that an adjustment may have occurred that month because the next highest monthly expense for group insurance was $185,890 in November 1985.

182. The amount of each party's adjustment appears to depend heavily upon the given 12 months that were examined. In other words, a different adjustment can be derived simply by picking and choosing the beginning and ending months that are examined. During several of these months, it appears that accounting adjustments have been made to correct previous months' expenses. It makes sense to this Commission that the corrections may well be for the fringe benefits expenses recorded in January, February, March, or April of 1985. The proposals of MCC and MDU basically ignore this possibility because of the time periods involved in their adjustments. Because of the volatility associated with these expenses over any given time period, and because both witnesses proposals reflect accounting adjustments which are probably more appropriate for inclusion in the test year, this Commission finds that an adjustment to fringe benefits expenses should not be made in this proceeding.

Additional Coyote O&M

183. This adjustment reflects increased operation and maintenance expenses (O&M) associated with the Coyote plant increments purchased in September, 1985 and May, 1986. MDU originally requested $103,284 for this expense increase, but revised that request to reflect changes in labor costs discussed in Finding of Fact No. 174. The Company's revised proposal would provide $95,055 for these expenses.

184. Mr. Clark of MCC has reviewed the Company's proposal and believes it to be overstated. This is because the Company's proposal provides for a full year of adjustment for the September, 1985 increment. Mr. Clark believes this provision to be in error because the actual 1985 expenses booked by the Company already contain the O&M expenses for September through December in 1985 (MCC Exh. 5, pp. 42-43). Mr. Clark proposed to include O&M expenses for the 1985 increment corresponding to the eight months that were not booked during the test period. Additionally, Mr. Clark proposed to include a full year's O&M expenses for the 1986 Coyote increment. This proposal is based on Mr. Clark's labor expense proposal, and represents an increase of $83,993.

185. The Company did not rebut Mr. Clark's statement. The Commission has reviewed the Company's proposed adjustment and agrees with Mr. Clark that MDU has effectively double counted O&M expenses for September through December, 1985. Therefore, the Commission accepts Mr. Clark's proposal with consideration given to the Commission's treatment of labor expense as discussed in Finding of Fact No. 177. The result is an increase in O&M expenses of $84,220.

Association Dues

186. Mr. Ball of MDU proposed to restate the industry association dues "to include only those items which relate directly to Montana and the appropriate portion of those items which are of a company-wide nature and thus benefit all of Montana-Dakota's customers" (MDU Exh. Q, p. 10). The Company's proposed adjustment would decrease expenses by $6,697. MCC witness Clark went beyond the level proposed by MDU by approximately $12,000. Based on some guide lines for exclusion (MCC Exh. 5, Exh. AEC-1, Sch. 2, p. 5b), Mr. Clark excluded the costs associated with

some organizations because they do not provide any benefit to Montana electric customers and others to comply with prior Commission treatment of association dues (MCC Exh. 5, p. 39).

187. MDU did not rebut Mr. Clark's proposal and has not demonstrated to this Commission that these association dues actually benefit Montana electric consumers. The adjustment proposed by Mr. Clark is viewed by this Commission to be quite appropriate. Therefore, the Commission finds a reduction in per books association dues expense of $18,776 to be proper in this proceeding.

Rate Case Expense

188. The Company adopted an accounting procedure that recognizes previously authorized rate case expense levels for book purposes. Because of this procedure, an adjustment must be made to balance per books rate case expense with the amount expected from this proceeding. MDU's and MCC's proposals are identical (MCC Exh. 5, p. 38). The Commission, therefore, finds a reduction in rate case expense in the amount of $142,104 to be proper in this proceeding.

Director's Meetings

189. Mr. Clark of MCC proposed an adjustment of $633 associated with the Company's February, 1985, Board of Directors meeting held in Palm Springs CA. His proposal is to restate the daily expenses of this meeting at the levels experienced for these meetings that are held within MDU's service territory. The Company did not rebut Mr. Clark's proposal.

190. The Commission will not tell the Company where to hold its Board of Directors meetings, but the Commission cannot allow additional costs that result from these meetings being held outside the Company's service territory to be passed on to the ratepayers. Therefore, the Commission finds a $633 reduction to Board of Directors meeting expense to be proper in this proceeding.

Insurance Expense

191. Mr. Ball of MDU proposed an increase to insurance expense to reflect rising insurance costs over December, 1985, levels. Mr. Ball's proposal would be an increase to Montana expenses of $13,589.

192. Mr. Clark of MCC reviewed the data used by the Company to support its adjustment and found much of the increase was due to unsupported estimates (MCC Exh. 5, pp. 40-43). He then eliminated these unsupported increases and found that the going level of insurance expense is actually $8,417 lower than in 1985. The Company did not rebut Mr. Clarks proposal, and the Commission agrees with Mr. Clark that unsupported increases cannot be allowed. The Commission, therefore, finds a $8,417 decrease to insurance expense to be proper in this proceeding.

Retired Plants O&M

193. The Company retired several old and unreliable plants during 1985 and 1986. As a result, the O&M costs associated with these plants are no longer being incurred by the Company. MDU and MCC agree about the level of costs which will no longer be incurred. The Commission, therefore, finds a $295,895 decrease for O&M expenses no longer being incurred to be proper in this proceeding.

Advertising

194. Mr. Ball of MDU proposed a $4,765 reduction to remove promotional and institutional advertising from the per books level of expenses. After reviewing the Company's proposal, Mr. Clark found that the level proposed by MDU was in compliance with past Commission decisions (MCC Exh. 5, p. 38). The Commission agrees with the methodology used to arrive at this adjustment, and finds a $4,765 decrease to the per books level of advertising expense to be proper in this proceeding.

Air Heater Baskets

195. In response to Data Request No. PSC-155, MDU stated that the air heater baskets at the Coyote plant were replaced during 1985. The total cost incurred in replacing these air heater baskets, $436,459 on a total company basis, was recorded in Account No. 512, an operation and maintenance expense account. The data request further asked if this amount should be expensed or capitalized. The Company responded that the amount should be expensed.

196. Mr. Kroeber of MDU was asked how often air heater baskets are replaced at the Coyote station. He replied that it depends on the wear and tear on the baskets. Mr. Kroeber also stated that these air heater baskets have never been replaced until the test year (TR p. 303).

197. The Coyote station went on line in 1981. That means that these air heater baskets provided a benefit for four years before being replaced in 1985. The Company believes that the total costs associated with replacing the baskets should be expensed (Finding of Fact No. 195). The Commission finds that an expense item this large, which provides a benefit for more than just the current test period, should be matched to the period of time that the air heater baskets will be in use. The Commission finds a four year amortization of this expense will provide the proper match of benefits and costs. Allocated to Montana using MDU's Factor No. 44, Production O&M, this issue represents a $101,268 decrease to per books operation and maintenance expenses that the Commission finds to be warranted in this proceeding.

EPRI Dues

198. Mr. Ball of MDU proposed an adjustment to reflect the actual level of cost presently being incurred by the Company. Mr. Clark of MCC reviewed Mr. Ball's proposal and found it to be acceptable (MCC Exh. 5, p. 38). The Commission examined the proposal and found it to conform with past treatment of this issue. Therefore, the Commission accepts the proposed adjustment, resulting in a $4,863 increase to the Company's per books level of EPRI dues.

Depreciation Rates

199. Mr. Ball of MDU proposed an adjustment to decrease annual depreciation expense by $82,041. The Company's proposal comes from changes in the depreciation rates associated with

several classes of depreciable plant (MDU Exh. Q, p. 11). Several of these depreciation rates are proposed to decrease, but the rates at the Big Stone, Coyote, Heskett, and Lewis and Clark generating stations are proposed to increase in order to recover estimated decommissioning costs of these plants.

200. Mr. Clark or MCC recommended that the Company be allowed to change its depreciation rates for all plant accounts except the four generating stations listed above. This proposal would result in a $428,459 decrease in depreciation expenses. He agrees that it is proper to include a provision for estimated removal costs in the depreciation rates because it "will result in a proper rate-making matching of service costs and service benefits" (MCC Exh. S, p. 47). However, given this belief, Mr. Clark concluded that the Company's removal cost estimates are highly speculative and the remaining lives of these plants are probably much longer than those used by the Company, especially for the Coyote (33 years) and Big Stone (32 years) plants (MCC Exh. 5, p. 49).

201. The estimated decommissioning costs for these plants were developed in a study performed by Stone & Webster Management Consultants, Inc. After reviewing this study, Mr. Clark testified:

> The decommissioning cost estimates are replete with rule of thumb allowances and estimates based on sweeping judgements, many of which appear to be based on Stone & Webster's experience in building power plants, but none of which are based on anyone's experience with dismantling a power plant of these sizes (MCC Exh. 5, p. 51).

202. Pertaining to the lives of the Coyote and Big Stone plants, Mr. Clark referred to two articles from the EPRI Journal and the Public Utilities Fortnightly that placed the average retirement age of generating units at approximately 45 years. Coupled with an expected life of 50 and 46 years at the Heskett and Lewis and Clark plants, this information suggested to Mr. Clark that a 40 or 50 year life would be more appropriate for the Coyote and Big Stone plants.

203. Mr. Clark believes the current depreciation rates will provide for the recovery of decommissioning costs, assuming 40 year lives for the Coyote and Big Stone plants. He also believes that the existing depreciation rates for the Heskett and Lewis and Clark plants already provide for decommissioning costs (MCC Exh. 5, p. 52).

204. Mr. Strand, an employee of Stone & Webster, rebutted Mr. Clark's argument about plant lives on behalf of MDU. Mr. Strand questioned the usefulness of the articles referred to by Mr. Clark. He stated that the expertise of the authors of these two articles are in areas of "mechanical systems design and reliability" and "policy analysis" (MDU Exh. F, pp. 5-8). Mr. Strand further noted that the subjects of these two articles were life extension of older plants and changes in air quality associated with older plants being run longer, not the subject of proper plant lives for depreciation purposes. Additionally, Mr. Strand provided the results of a 1985-1986 survey performed by Edison Electric Institute's Depreciation Accounting Committee which shows that the Big Stone and Coyote plant account lives are very comparable with the lives used by the 78 companies in the survey (MDU Exh. F, pp. 4-5).

205. Mr. Chekos, another Stone & Webster employee, rebutted Mr. Clark's statements about the accuracy of the decommissioning cost estimates. He stated:

> Extensive documentation, including engineering drawings, construction cost reports and site investigations, was used in conjunction with the in-house engineering, construction and estimating expertise of the Stone & Webster organization. Judgment based on common sense founded on actual experience and knowledge can hardly be characterized as "rule of thumb allowances and sweeping judgements." (MDU Exh. E, p. 4)

206. The Commission finds the Company's evidence about the plant lives to be more convincing than MCC's. MDU based its estimates on knowledge of specific operating conditions at each plant. Mr. Clark based his estimates on two magazine articles. The articles relied on by Mr. Clark speak in general terms and often refer to extensive capital investments needed to extend the present lives of older plants. Not only did the Company present evidence showing the useful lives of Coyote (33 years) and Big Stone (32 years) are very comparable with 78 ether utilities average plant lives (Finding of Fact No. 204), but the Commission observes that Montana Power Company and Pacific Power and Light are currently depreciating the Colstrip 3 plant over a similar time period (35 years).

207. Mr. Clark does raise an important issue, however, when he mentions Stone & Webster's estimates are not based on any experience at dismantling such plants (MDU Exh. 5, p. 51).

Both parties agree that some amount of decommissioning costs will result when these plants are retired, so the only question left is: what is a reasonable approach for this Commission to follow in order to provide a proper match of benefits and costs?

208. The Commission's method in this case is similar to the treatment afforded MDU with respect to the older plants retired during 1985 and 1986 (Findings of Fact Nos. 89-98). First, the 15 percent contingency factors are removed. Second, when the accuracy of Stone and Webster's estimates of decommissioning costs at the retired plants are known, then the Commission will adjust the depreciation rates of the Big Stone, Coyote, Heskett, and Lewis and Clark plants in the Company's next general electric rate case if needed. This treatment results in the following depreciation rates:

	Big Stone	Coyote	Heskett	Lewis and Clark
Rate	4.17%	3.33%	4.17%	4.28%

209. As a result of these rate changes, the Commission finds a $150,762 decrease to the Company's per books level of depreciation expense to be proper in this proceeding. The corresponding adjustment to accumulated depreciation results in a rate base increase of $75,381.

210. Additionally, the Company is to establish an accounting procedure to record the funds raised for these decommissioning costs in distinct and separate accounts. This will insure that these funds are used to pay only the Montana ratepayers' share of decommissioning costs when these plants are retired.

Other Depreciation

211. Both parties presented several adjustments to reflect depreciation expenses on rate base items that were not fully reflected in the Company's 1985 per books expenses. Based on the depreciation rates approved by the Commission, the following adjustments to depreciation expense are found to be warranted in this proceeding:

Annualize 1985 Coyote & Big Stone Purchase	$46,508
1986 Coyote Purchase	45,120
Depreciation on CWIP in Service in 1985 but not Booked Until 1986	5,334

Total	$96,962

Amortization

212. Several adjustments were proposed by the parties to increase amortization expenses. Pursuant to Findings of Fact Nos. 77, 96 and 107, the Commission finds the following amortization expenses to be warranted in this proceeding:

Acquisition Adjustments	$71,774
Deferred Depreciation & AFUDC on Coyote	33,636
Net Negative Salvage on Retired Plants	227,124
Total	$332,534

Public Affairs

213. In 1985, the Vice President of Public Affairs had an expense account which totaled $45,121. The Company was requested to provide backup material to support this level of expense. MDU responded that the requested information would have to be gathered outside of the normal accounting process through a detailed study of the Company's records. This process would require the Company to pull numerous expense reports and accompanying receipts, which would be very time consuming (MDU Exh. 3, Response to Data Request No. PSC-159).

214. An officer's expense account totaling $45,121 causes serious concern to this Commission. When the Company refuses to provide any support for such an expense, then the Commission must question the reasonableness of the expense. The Company has failed to verify this level of expense. The Commission cannot allow expenses to be charged to the ratepayers just because they exist on the Company's books. Therefore, this expense must be eliminated for rate making purposes.

215. The exact amount of this expense that was charged to Montana electric operations is not known. Therefore, the Commission must make its best estimate. In 1985, MDU electric operations were charged with 32.5 percent of the total expenses of the Public Affairs Department (MDU Exh. B, Response to Al Clark General Data Request No. 3, Attachment A). This expense was recorded in Account No. 921 (MDU Exh. B, Response to Data Request No. PSC-159), an

Administrative & General Office Account (MDU Exh. A, Rule 38.5.156, Statement G, p. 6), which is allocated to the jurisdictions with Factor No. 28 (MDU Exh. A, Rule 38.5.176, Statement L, Part C, p.12). Based on this information the Commission finds a $3,794 decrease to per books operation and maintenance expenses to be proper in this proceeding.

Production Tax

216. MDU and MCC proposed two different adjustments to the level of per books production taxes. Because the Commission accepted MDU's proposed power supply mix, it is appropriate to establish the production taxes based on that same production level. Based on the approved plant energy production levels, The Commission finds a $549 decrease in production taxes to be proper in this proceeding.

MCC Tax

217. MDU and MCC proposed nearly identical decreases in the level of MCC taxes to reflect the effects of a decreased tax rate. The Commission finds the lower tax rate to be a known and measurable change. The Company's per books level of sales revenue was $31,261,354 and the Commission found a $3,822 increase in these revenues to be proper in this proceeding (Finding of Fact No. 124). Based on that level of sales revenue, the Commission finds a $21,883 decrease to the per books level of MCC taxes to be appropriate in this proceeding.

PSC Tax

218. The .225 percent PSC tax was enacted after the 1985 test year; therefore, the Company did not collect any money to pay this tax during 1985. Both parties have proposed adjustments to reflect the effects of this tax based on the level of sales revenues they proposed. The Commission recognizes this tax as a known and measurable change occurring within 12 months of the test year. The Company's per books level of sales revenue was $31,261,354 and the Commission found a 53,822 increase in these revenues to be proper in this proceeding (Findings of Fact No. 124).

Based on that level of sales revenue, the Commission finds an increase of $70,347 for the PSC tax to be proper in this proceeding.

Ad Valorem Tax

219. Mr. Ball of MDU proposed a $52,101 adjustment to the per books level of ad valorem taxes based on the Company's determination of average plant balances. Mr. Clark of MCC proposed a $29,215 adjustment to increase ad valorem taxes reflecting the current rates on his determination of pro forma average plant balances for MDU. The difference between the two proposals is due to the way each party calculated the adjustment. ,Mr. Ball's proposal calculates the ad valorem taxes on a total Company basis (MDU Exh. A, Rule 38.5.174, Statement K, p. 1), compares that number with the per books number, and then allocates the difference to each jurisdiction (MDU Exh. A, Rule 38.5.174, Statement L, Part C, pp. 29-30). Mr. Clark starts with the plant balances that have been allocated to the Montana jurisdiction, calculates the appropriate level of ad valorem taxes, and then compares this level to the per books level to arrive at his adjustment (MCC Exh. 5, Exh. AEC-1, Sch. 2, p. 13).

220. Theoretically, if the taxes were allocated correctly, the two methods would arrive at the same value. Neither party provided testimony about the merits or drawbacks of the two methods, but the Commission finds that Mr. Clark's method provides a more precise match between the assets allocated to Montana and the corresponding ad valorem taxes assessed on those assets. Therefore, the Commission accepts MCC's adjustment, resulting in a $29,215 increase to the per books level of ad valorem taxes.

Elimination of Income Tax Rounding
and Prior Years' Adjustments

221. The Company proposed two adjustments that provide for the elimination of prior years adjustments and rounding to adjust current income taxes to the amount calculated for Montana based on test period data and to eliminate the prior year's closing/filing adjustments in deferred taxes (MDU Exh. Q, pp. 14-15). Mr. Clark proposed two identical adjustments on behalf of MCC. These

two adjustments are commonly made and have previously been accepted by this Commission. Therefore, decreases in current income taxes of $12,405 and deferred income taxes of $5,895 are warranted in this proceeding.

Income Tax Effect of 1986 Coyote Purchase

222. Because tax depreciation rates are higher than book depreciation rates, a myriad of adjustments must be made to show the current and deferred income tax effects of the 1986 Coyote purchase. The Commission finds a current income tax decrease of $11,234, a deferred income tax increase of $10,409, and a rate base decrease of $5,205 for accumulated deferred taxes all to be proper in this proceeding based on the approved 3.33 percent (Finding of Fact No. 208) Coyote depreciation rate. The calculation is shown below:

Montana Portion of 1986 Coyote Increment (Finding of Fact No. 83)	$1,354,950	
Tax Depreciation at 5% ACRS Rate		67,748
Book Depreciation at 3.33% Approved Rate	45,120	
Tax Depreciation in Excess of Book Depreciation		22,628
Current State & Federal Income Tax Effect at 49.6%		-11,234
Deferred Federal Income Tax Effect at 46%	10,409	
Accumulated Deferred Taxes		5,205

Interest Synchronization

223. MCC witness Clark calculated pro forma interest expense using the same procedure employed by the Company. The interest expense Mr. Clark calculated is lower than the Company's because he used his adjusted rate base and MCC witness Copeland's weighted debt cost rather than the rate base and weighted debt cost proposed by MDU. The Commission finds that a pro forma interest adjustment is proper to reflect the income tax effect of interest expense. By utilizing the approved rate base and weighted cost of long-term debt in the methodology, the Commission finds an decrease to Montana Corporation License Tax in the amount of $45,310 and an decrease to Federal Income Tax of $287,935 to be proper in this proceeding.

Amortization of Pre-1974 Gain

224. Both parties proposed a $14,000 increase in net operating income to recognize the amortization of pre-1974 gains on reacquired debt. Mr. Clark of MCC offered an explanation of the proposed adjustment:

> Before 1974, MDU credited the gain on reacquired debt directly to retained earnings. Since 1974, the gains have been credited to Account 257 - Unamortized Gain on Reacquired Debt. This account has been treated in the past as a rate base deduction. But the pre-1974 gains are not included therein (MCC Exh. 5, p.30).

The Commission has consistently ruled that pre-1974 gains on reacquired debt should be flowed through to ratepayers over time in order provide the benefit to those who had been paying for the cost of the debt before it was retired. The Commission, therefore, finds a $14,000 increase in net operating income to be proper in this proceeding.

Revenue Requirement

225. The following table shows that additional annual revenues of $2,290,229 are needed by the Company in order to be allowed the opportunity to earn an overall return of 10.655 percent:

	MDU Per Books	Total Accepted Adjustments	Final Accepted Pro Forma	Approved Revenue Increase	Approved Final Total
Operating Revenues	31,897,888	23,056	31,920,944	2,290,229	34,211,173
Expenses:					
Fuel & Purch. Power	8,730,914	1,069,142	9,800,056		9,800,056
Operating & Maint.	8,775,817	(586,946)	8,188,871		8,188,871
Total O&M Expenses	17,506,731	482,196	17,988,927		17,988,927
Depreciation	3,648,972	278,734	3,927,706		3,927,706
Taxes - Non Income	1,421,245	77,130	1,498,375	5,840	1,504,215
Fed. And State Tax	1,910,346	(761,492)	1,148,854	1,134,085	2,282,939
Deferred Income Tax	1,126,940	4,514	1,131,454		1,131,454
I.T.C.	260,326		260,326		260,326
Amort. Of I.T.C.	(6,297)		(6,297)		(6,297)
Total Operating Exp.	25,868,263	81,082	25,949,345	1,139,925	27,089,270
Amortize Pre-1974 Gain		14,000	14,000		14,000
Operating Income	6,029,625	(44,026)	5,985,599	1,150,304	7,135,903
Rate Base	63,949,639	3,022,707	66,972,346		66,972,346
Rate of Return	9.429%		8.937%		10.655%

PART E

1986 TAX REFORM ACT

226. MDU filed its response to Order No. 5236, Docket No. 86.11.62 on January 30, 1987. In that response, the Company reported that the Tax Reform Act (TRA) would cause a $605,000 reduction in its required revenue requirement based upon the cost of service contained in MDU's rebuttal testimony in Docket No. 86.5.28. The Company's response further explained that the impacts of the TRA would be less if the Commission granted a lower rate increase than the Company had requested in this docket.

227. The TRA was not enacted until after this docket was filed and, consequently, was not initially an issue in this proceeding. The TRA information MDU filed is based upon data from this proceeding and suggests that the Company's electric customers are entitled to a reduction in rates. The Commission requests the Company to submit the TRA impacts based upon the findings of this order and the methodology it employed in response to Order No. 5236. The impacts will then be incorporated into the final revenue increase in this proceeding.

228. The above-described treatment of the TRA does not affect Docket No. 86.11.62 in any way. This treatment is merely a way for the MDU electric customers to benefit now from the amount of decrease that the Company concedes will occur. MDU remains a participant of Docket No. 86.11.62, and its rates will be subject to any changes resulting from the Commission's decision in that docket.

PART F

OTHER ISSUES

Western Power

229. MDU is a member of the Midcontinent Area Power Pool (MAPP). As such, it customarily buys electricity from other MAPP members when it is cheaper than producing that electricity at one of the Company's own plants. The Commission agrees that this is a rational way to operate because it minimizes costs.

230. Presently, many utilities that operate to the west of MDU, outside of the MAPP system, have excess electricity to market. During the hearing, Commissioner Driscoll asked Mr. Kroeber if the Company would buy electricity from these western sources if such a purchase was cheaper than producing the power at MDU's plants. Mr. Kroeber's response indicated that this proposition has not been considered by MDU (TR pp. 273-275).

231. The Company has an obligation to provide adequate service at reasonable rates. As such, this Commission wants to make sure that the Company considers all of the options when it acquires additional resources. The transmission system between MDU and the western power sources may not presently be adequate to allow large scale energy transfers, but the incentives of purchasing power from the west may well merit upgrading the present facilities. Displacement sales could also help alleviate concerns about possible transmission problems. In short, the Commission requests that the MDU seriously consider the possibility of buying power from the west by analyzing the possible costs and benefits of such a transaction.

Peak Load Forecasts

232. In his direct testimony, Mr. Kroeber, of MDU, stated that the Company's peak load forecasts have been accurate in the past and are expected to be in the future. In support of this statement, he listed the following forecasted and actual summer peaks (MDU Exh. P, p. 11, 15 percent reserve margin included):

	1983	1984	1985
Forecast	390 MW	421 MW	430 MW
Actual	389	415	403
	------	------	------
Difference	1 MW	6 MW	27 MW

Mr. Kroeber blamed abnormal weather conditions for the difference between the forecasted peak and actual peak in 1984 and 1985. It is not clear whether these forecasts were all made at the same time or at varying times between 1983 and 1985. Mr. Kroeber did not provide the date that each forecast was determined. If the above forecasts were made at the beginning of each year, then Mr. Kroeber's example provides no information about the accuracy of MDU's long term peak load forecasts. In such an occurrence, the Commission would have no information about the validity of the Company's long term resource plans.

233. In order to check the reasonableness of MDU's forecasts over a longer period, the Commission examined the Company's projections from Docket No. 83.9.68, MDU's most recent general electric rate case. Forecasts from that proceeding are compared to actual peaks below (TR pp. 253-254, 280-281, 15 percent reserve margin included):

	1984	1985	1986
Forecast	421 MW	435 MW	447 MW
Actual	415	403	389
	-----	-----	-----
Difference	6 MW	32 MW	58 MW

Based on this information, the Commission questions the Company's ability to accurately forecasting long term peak requirements when it is already having problems forecasting a three year period.

234. As stated earlier, Mr. Kroeber blamed the 1984 and 1985 differentials on poor weather conditions. He further testified that the 1986 peak had occurred in June, indicating that July and August were rather cool because that was the first time to his knowledge that the peak had ever occurred as early as June (TR. p. 254). In support of the Company's position, it must be noted that the actual peak did decline in 1985 and 1986. To conclude that actual peak loads will consistently decrease would defy all knowledge that peak loads actually tend to increase over the long term.

235. Weather may well influence MDU's actual peaks, but the Company has performed no studies of the effect weather has on its system (Response to Al Clark Audit Data Request 6). Because there are no studies, it would suggest to this Commission that the Company is only assuming that weather is the reason for inaccuracies of the 1984, 1985, and 1986 forecasts, when in fact, other factors may well be to blame. Such occurrences as changing consumption patterns, conservation, and changes in the economy could also cause peak demand to decrease. By not determining, or even attempting to determine, the actual affect that weather has on peak demand, the Company may well end up overbuilding its system based on falsely inflated forecasts. The Company is hereby alerted that it is expected to address this issue in the next MDU general electric rate proceeding.

Weather Normalization

236. If weather conditions can largely influence MDU's peak load requirements, it would logically follow that the Company's energy sales would also be affected. This means that when the test year weather is abnormal, then the Company's total revenues may also be abnormal. For instance, if summer weather is cooler and wetter than normal, the need to irrigate fields, and air condition buildings will undoubtedly be lower than if normal weather conditions had prevailed.

237. When weather conditions have a significant impact on a company's operations, normalizing can provide a smoothing effect on the revenue requirement. This in turn can help promote rate stabilization for the Company's electric customers and provide a more realistic approach to regulating MDU. The Commission expects MDU to address this issue in its next general rate proceeding.

PART G

COST OF SERVICE

Introduction: Cost of Service and Rate Design

238. The issues that will be addressed in this section of the order generally include how costs are allocated to the various classes, the so-called "cost of service" portion, and how prices for the various goods and services should be set, the so-called "rate design portion." Additional issues, including proposed language changes on tariffs etc., that do not neatly fall into one of these two general categories are discussed in a later section.

239. A COS/RD model involves numerous steps to arrive at final prices. Table 1 below illustrates some of the general steps involved in setting prices under the existing regulatory institution. Costs are first sorted by function. Functionalized costs are classified based on the product produced i.e., energy, capacity or customer access. Classified costs are further refined to reflect time of use and voltage level of service cost variations.

Table 1
A General Cost of Service and Rate Design Model

Cost of Service

Function	Classified	Allocated	Reconciled	Rate Design
Generation Transmission Distribution	Energy, Demand & Customer Access	Seasons, Times of Day and Customer Classes	Uniform Percent or other e.g., market based	c/kwh $/kw, $/customer

240. The model described in Table 1 is very general and excludes many detailed technical steps. For example, the model as described ignores one type of analysis that may be performed and in turn the basis of optimal cost allocations and prices. This analysis, which is called a welfare economics analysis, will not be discussed here.

241. The organization of the balance of this order follows the general COS/RD model in Table 1. First, each parties' COS model is reviewed, followed by the Commission's decisions on COS. Second, each parties' reconciliation approach is reviewed which again is followed by the Commission's decisions. The third step provides the parties' rate design proposals and the Commission's decisions. Finally, other issues are discussed including e.g., language changes on the tariffs and decided upon by the Commission.

Background: Cost Of Service and Rate Design

242. Prior to MDU's filing of Docket No. 86.5.28, the Commission's most recent decisions on MDU electric cost or service and rate design stemmed from Order Nos. 5036a, b in Docket No. 83.9.68. Order No. 5036a (issued July 5,1984) provided the essential Commission decisions on how the Company's embedded accounting cost revenue requirement was recovered from the numerous classes of service.

243. In the instant docket, the Commission granted interim relief of $884,507 in Order No. 5219a (in Interim Order No. 5219 interim relief of $942,582 was granted). As in a prior gas docket (No. 85.7.30), the Commission in the instant docket opted to not apply a "uniform percent increase" (UPI) to recover the increased revenue requirement.

244. The method applied by the Commission in the instant docket to recover the increased interim revenue requirement involved several steps. First, the "revenue levels" from each customer

class were increased by a uniform percent, with the exception of private lighting (Rate 24). Second, for classes with Base Rates, the Base Rate was increased to the lowest common denominator proposed by the MCC and MDU. Third, the resulting Base Rates were reduced downward (or other rates increased) if the revenues generated exceeded (fell below) a class' interim revenue requirement. Exception to this process was taken with respect to optional time-of-day rates 16 and 23 for residential and business customers. Rates for these latter classes were left unchanged pending a final order.

245. The following reviews the Company's and Montana Consumer Counsel's cost of service (COS) testimony. MDU's testimony, sponsored by Mr. John Castleberry, is reviewed first followed by a review of the Montana Consumer Counsel's testimony, sponsored by Mr. Jim Drzemiecki. The Commission's decision on each COS issue is provided.

<u>MDU Cost Of Service</u>

246. <u>Generation</u>. There are two parts to MDU's functionalized generation marginal costs which include energy (c/kwh) and peaking capacity ($/kw). MDU used its Electric Generation Cost (EGC) model to simulate the merit order dispatch of generation resources to compute marginal energy costs (system lambdas) for on- and off-peak periods. An average of the sum of the 1986-1990 present worth values of these costs was then computed.

247. Peaking capacity-related demand costs were computed using an Alternative Scenario Methodology (ASM). With the ASM, MDU computes the cost differential between a base case expansion plan and a change case plan assuming a 10MW decrement and 1987-2001 purchased power costs (excluding 1988). The resulting avoided Mid-Continent Area Power Pool (MAPP) Sch. "H" Costs were levelized in real terms.

248. <u>Transmission</u>. There are also two parts to MDU's functionalized transmission marginal cost calculation including capital investment and O&M; both are demand costs ($/kw). The capital part derives from a regression of transmission investment (net of those components related to facilities replacement and remote baseload) on increased peak demand, both in cumulative terms, using historic and forecast data. The O&M part also derives from a regression analysis.

249. Distribution. While the method of calculation differs, MDU also computes functionalized distribution demand costs ($/kw) also made up of capital and expense components.

250. The demand-related capital part is a net calculation. For historic and forecast costs (1976-1990), MDU regresses the net cost of distribution system additions on peak demand. The sense in which the costs are "net" is that MDU first reduces the distribution investment by an estimate of the customer-related part using seven years of average cost data in constant 1986 dollars.

251. MDU's estimate of distribution expenses derives from a classification of total expenses by demand and customer. The classification stems from MDU's Fully Allocated Embedded Cost of Service study. Demand-related expenses for each year are divided by the annual Montana distribution peak for each year and averaged.

252. Customer. MDU's customer-related costs derive from a "minimum investment per customer" philosophy. With this approach, MDU computes the cost required to connect a new customer in Montana and in 1985. This current cost estimate is annualized and adjusted for overhead and expenses.

253. Table 2 below summarizes some key results from MDU's marginal COS study.

Table 2
MDU's Marginal Cost of Service Study:
Classified Cost Results

Function (voltage)	Energy c/kwh		Demand $/kw	
	ON	OFF	ON	OFF
I Generation				
Secondary	1.996	1.716	30.34	6.24
Primary	1.910	1.667	28.56	5.87
Trans	1.873	1.645	27.95	5.74
II Transmission				
Secondary			86.48	17.77
Primary			81.39	16.73

Trans	79.65	16.38
III Distribution		
Secondary	37.95	7.77
Primary	35.67	7.31

Source: Exh. H. Energy costs are from JKC-9. Demand costs derive from JKC-9 and were allocated to on- and off-peak periods based on JKC-7. Customer Costs can be found on JKC-5.

MCC Cost of Service

254. Overview. MCC functionalizes system costs differently than MDU. First, MCC splits costs into Bulk and nonBulk categories. Bulk Power Supply Costs (BPSC) include "generation and higher voltage transmission" costs and, according to MCC, account for over 75 percent of the cost of providing electricity. Other system costs are nonBulk Power costs. The following reviews MCC's COS testimony using the same format used with MDU.

255. Generation. There are several types of generation costs included in MCC's direct testimony. The first is energy and derives from MDU's cost data. The second is the provision of capacity to meet peak demand. The former ranges from 1.374 to about 1.576c/kwh depending on the time-of-day (TOD).

256. MCC's COS study contains two types of generation capacity costs. First, MCC argues to base the cost of peaking capacity on the lowest cost source. In turn, this source for MDU is MAPP purchases that equals $13.73/kw/year. This figure is MDU's calculation but only adjusted for O&M and a 15 percent reserve requirement. The second type, while appearing to be a reconciliation measure, involves a "...reassignment of some of the costs of power production from the demand component calculated on an average embedded basis to the energy component..." and will be discussed in detail below.

257. Transmission. MCC delineates three sub-functions provided by transmission capacity including: 1) energy-related; 2) peaking-capacity related, and 3) system-reliability related. However, MCC only reflects peaking capacity costs in its incremental BPSC. Whereas MCC uses MAPP as the source of peaking capacity costs, MCC holds that the marginal cost of transmission is the

"associated" cost to connect added bulk power loads at the time of system peaks. This cost amounts to $5.48/kw/yr when annualized. Then, the total Bulk Power capacity costs are $19.21/kw/yr.

258. Other Functional Costs. MCC's estimates of non-BPSCs derive from MDU's embedded cost of service study. MCC argues that the reasons for basing generation type costs on marginal cost analyses do not hold for the development of distribution and customer costs. However, MCC modified MDU's embedded costs for use in its COS study.

259. MCC's changes regarded the classification of distribution plant investment in poles, towers, fixtures, conductors, conduits and line transformers in FERC accounts 364-368. The following table shows a comparison of MDU's and MCC's classification of these accounts to demand purposes (one minus MDU's percent was classified to customer related). MCC allocates these classified demand costs on the basis of non-coincident peak demands of customers, retaining MDU's voltage level of service distinction.

Table 3
Comparative Classifications of Certain
Types of Distribution Plant

		Percent Classified to Demand	
Account	Plant	MDU	MCC
364	Poles etc	35	100
365	Conductors (Over)	35	100
366	Conduit (Under)	70	100
367	Conductors (Under)	70	100
368	Line Transformers	72	100

Commission Decisions on Cost-of-Service

260. Introduction. The Commission would first like to summarize its philosophy on the use of marginal costs in cost of service.

261. Generally, the Commission agrees with MCC and disagrees with MDU on the import and use of marginal costs. MDU is generally wrong in stating that the use of marginal costs in the apportionment of revenue requirements tends to waste and misallocate society's scarce resources (Exh. H, p. 11), unless of course the estimated marginal costs are incorrect. As stated by MCC, marginal costs should be utilized to determine both inter-class and intra-class revenue

responsibilities (Exh. MCC-2, p. 12). It is this philosophy that is reflected in recent Commission electric cost of service decisions involving MPC, PP&L or MDU. The economic logic for this position was clearly stated by the MCC in this docket (ibid).

262. As a preliminary matter, the Commission insists that the revised cost study reflect January 1, 1988 dollars. That is, all costs components must be updated from the 1986 base year. The reasoning should be clear: The earliest that final prices out of this docket will be tariffed is roughly April 1987. Moreover, the cost-based prices that result from this docket may be in place well into 1989 if the time lapse from the Commission's final order out of Docket No. 83.9.68 to the tariffing of final rates out of the instant docket is any indication.

263. Generation. To summarize, the Commission finds neither MDU's nor MCC's cost development, as regards generation costs, to be complete. The following discusses revisions that must be made to the three principle components of functionalized generation costs: 1) running costs (lambda), 2) peaking capacity costs, and 3) baseload generation costs.

264. First, with regard to running costs, it is evident from MDU's revised testimony (TR 93) that there are at least two ways to compute this component of the COS study. The approach used by MDU in this docket is roughly the same as that proposed by MDU and approved by the Commission in Docket No. 83.9.68 (see Finding No. 181 of Order No. 5036a). However, MDU's preferred approach in the current docket is a real levelized value while the method used is a simple average of the sum of a series of present worth values. Then, there are two issues to be decided: 1) real levelized versus a simple average costing, and 2) the length of the costs used (e.g., 1988-1911).

265. The Commission finds that MDU's preference for real levelized costs has merit in that the approach jibes with the approach required by the Commission in the recent avoided cost docket (No. 84.10.64). The Commission is more concerned with the magic or arbitrariness of using five (5) years; in other jurisdictions twenty (20) years are used. Neither MDU or the MCC critically analyzed this issue. The ideal, if cost-effective technology permitted, would be to signal customers with the instantaneous cost of consumption (production). Until this issue is argued by the parties, a five year stream of projected costs, as proposed by MDU and as used by the MCC, but beginning with 1988, is approved.

266. In calculating the real levelized energy prices, MDU should include five years of data. As evident from the February 20, 1987, letter[1] and work papers, only four years of data were used with the January 1, 1988 dollar estimates. If possible, MDU should expand this base by adding a fifth year. In its compliance workpapers, MDU must also explain why the real levelized energy prices of 1.917 and 1.672, assumedly in 1986 dollars, fall to the levels of 1.577 and 1.257 when four years' of data and 1988 dollars are used (see MDU Late Filed Exh. 4 versus Exh. 5, p. 1 of MDU's February 20, 1987, work papers).

267. The second type of generation cost involves peaking capacity costs. Both MDU and MCC agree on the base value which is a real levelization of a fifteen (15) year cost stream. The two parties part ways on relevant additional adders or adjustments and also on real versus nominal levelization. The bottom line is more than a two-fold difference of opinion: $32.60/kw/yr/MDU versus $13.73/MCC. Until MDU provides an explanation as to how $22.00/kw/yr in marginal O & M demand expenses is avoidable on the demand-side of the equation, but should not be reflected on the supply-side of the equation, such costs will not be included ln developing marginal cost based inter-class revenue requirements.

268. On the issue of carrying charges, the Commission finds a real carrying charge should be used to annualize costs. MDU uses a real carrying charge to annualize costs (see Exh. H, pp. 12,

[1] In this docket, the Commission requested several late filed exhibits from MDU and MCC to clarify or substantiate evidence introduced by the parties during the hearing. The parties had ten days after the Commission received the exhibits to object. No objections were received to late filed exhibits.

13 and 19, and Exh. JKC-16). MCC assumed it had used, and prefers, a nominal carrying charge (see Exh. MCC-3 and Data Response No. PSC-MCC44-c). However, if one looks closer at the carrying charge used by MCC, one finds the MCC has either, unknowingly used a real carrying charge, or the MCC expects zero inflation: MDU's and MCC's transmission carrying charges are identical (13.832 percent). The Commission had hoped for a discussion on this issue. As with the avoided cost docket, the Commission finds a real carrying charge should be used.

269. The third type of generation cost involves baseload capacity. MDU did not factor into its marginal COS study any such costs. MCC, however, explicitly included in its COS study the "reassignment" of some costs (ibid, pp. 45, 53, and Data Response PSC-MCC43a). That is, the MCC, holding that the method is non-discretionary, increases the BPSCs proportionately to reconcile embedded accounting revenue requirements with its cost of service study results.

270. As an alternative to the above "reassignment" approach, the MCC later described another approach that involves applying the "Base-Peak" classification of generation costs to MAPP's Sch. B costs (TR 117-122).

271. For the following reasons, the Commission finds MDU must revise its marginal COS study to reflect the MCC's application of the Base Peak approach to MAPP Sch. B capacity prices. First, in the Commission's last avoided cost docket MDU testified that qualifying facilities (QFs) should be paid MAPP Sch. B prices under certain circumstances. The Commission approved MDU's proposal. Second, in this docket MDU stated that it will begin buying Sch. B in 1989 in the amount of 4MW, increasing up to 34MW per year in 1996 (Data Response No. PSC-138). Third, and as an indicator of the opportunity cost of baseload capacity in the region, MDU recited Minnesota Power and Light's offer at $15.50/kw/month.

272. The Commission finds that MDU must compute the energy value of MAPP Sch. B purchases in the following manner for inclusion in the revised COS study. It should be noted that MDU shows Sch. B purchases for the same time period (years and seasons) that Sch. H purchases are expected, but in larger quantities (70 percent Sch. B, 30 percent Sch. H). Using the same escalation and discount rates, MDU must compute the real levelized cost of Sch. B. Next, using the Base Peak approach MDU must compute the energy-related cost of Sch. B; that is, MDU is to

compute and deduct from a real levelized Sch. B cost calculation the $11.20/kw/year appearing on Exh. H. The difference must be divided by the number of hours per year and the result must be added to MDU's short-run marginal cost estimates.

273. Transmission. In past orders, the Commission has adopted MCC's logic for basing marginal transmission costs on the cost of connecting a peaking resource to the transmission system (e.g., Order No. 5036a, p. 76). In the instant docket, the Commission finds the same method should be used. A few comments on the issue are in order, however.

274. The development of marginal transmission costs, whether they be for energy or capacity purposes, was not in the Commission's estimation debated with much rigor. MDU's method begs an explanation as to why there are no energy-related costs in its analysis. MCC on the other hand argues that there are three different types of functionalized transmission costs, each with a specific purpose (ibid, pp. 35-6). MCC then only includes transmission costs "associated" with marginal generation-related peaking capacity costs (ibid, p. 38). Practically, there would not really appear need to incur any additional transmission capital costs to buy MAPP Sch. H peaking capacity as noted by MDU (re: Mr. John Castleberry's Rebuttal at p. 3).

275. Distribution. For the following reasons, the Commission finds relatively more merit in MDU's computation of marginal distribution-related costs. The Commission finds MCC's argument to classify certain distribution costs in the electric arena differently than in the gas arena to not have much logical support. One can make the same charge of MDU. While the investments are clearly and necessarily different (wire and poles versus pipe), the purpose they serve would appear analogous (TR 122, 123). Yet, between MCC and MDU, and for electricity and gas, there are four different opinions on how certain similar (in function) distribution plant should be classified between energy, demand and customer related. As there is no convincing argument on this issue, the Commission chooses to follow its precedent from Order 5036a, Docket No. 83.9.68.

276. As regards the allocation of distribution demand costs to times of day, the Commission disagrees with MDU's proposal. The Commission's concern relates, once more, to MDU's use of LOLHs. The Montana portion of MDU's system peaks in the winter, not in the summer with MDU's system peak. On this basis alone, it would not appear logical to use LOLHs that

are assumed related to the generation function. MDU must allocate distribution demand costs evenly to each hour of the year out of this docket, and not on a LOLH basis. MDU can propose improvements on this procedure in a motion or in its next case.

277. Customer. The development of relevant customer related marginal costs is also problematic. On one hand, the Commission agrees with both parties in that these costs are relatively less crucial than say generation costs in a marginal cost of service study. However, to the Commission there are minimum customer type costs that can and should be identified that are causally related to specific customer classes. MDU's Exh. H is useful in this regard. A data response provided the MCC's basis for customer costs (see PSC-MCC32-d).

278. The Commission's interest is to include as accurate a marginal customer cost estimate as possible in the revised MDU cost study. While the record is not well developed on this issue, there appears sufficient evidence. The Commission accepts MDU's marginal customer cost estimates (Exh. H, JKC-17) with the elimination of the first two types of costs appearing on p. 3 of this exhibit; that is, only the meter and service drop type costs should be carried forward. The cost to connect and transformer type costs should be excluded. This, in fact, was Mr. Castleberry's proposed adjustment in arriving at short-run costs (TR 72-74).

279. At least two reasons appear to support the exclusion of the two costs noted above. First, clearly the investment in distribution facilities associated with connecting a new distribution customer are accounted for in the Company's most recently proposed and approved line-extension policy (see existing Rate 112 and MDU Data Response No. 38 to the Commission staff); if not, then the Company's proposed line-extension policy would not appear to achieve its stated objective. Secondly, it is also clear that the associated facilities' useful lives, on average, have not elapsed; as a result, only on some sort of discounted present value basis, and not current, would the same costs be relevant in a marginal cost study. As with certain earlier issues, hopefully this issue will stir a critical debate in MDU's next filing.

280. Other Adjustments. Two adjustments must be made in the cost of service study involving the employee discount and reactive power charges.

281. First, with regard to the 33.3 percent employee discount, it is clear to the Commission that to include all associated billing determinant volumes in the residential class has the impact of placing the burden of this fringe benefit expense on just the residential class. This is not an equitable outcome. Employee costs are incurred to serve all classes. On the other hand, there is, at this time, no apparent best approach to causally attributing the fringe benefit to a particular product. Until such time that the issue is debated, the Commission finds that the portion of the residential class' reconciled revenue requirement associated with MDU employees must be identified and recovered from all other customers on a kwh basis. MDU will have to separate and show, for accounting purposes in the COS study, the cost of the employee discount.

282. Second, the Commission finds that the reactive power charge must be reflected in the COS study. For each and every class that has a reactive power charge e.g., existing tariff sheets 22, 25, 27, 30, 48, MDU must use the actual test year billing determinants and $1.90 as the marginal cost (see Data Response No. 34). In this regard, the Commission would note that the Company's Data Response No. PSC-73, which states the "...Commission approved the elimination of KVAR charges in Order No. 5036b...", is an apparent error as regards COS and rate design. This cost item must appear for each relevant class in the Company's workpapers.

283. Other Comments. One aspect of MDU's cost-of-service study appears flawed to the Commission and should probably be changed. As evident from the balance of this order, the apparent flaw impacts nearly all "downstream" reconciliation and rate design aspects of the order, and raises the Commission's concern for making any major cost allocation or rate design changes in this docket.

284. The apparent flaw relates to an inconsistency between MDU's LOLHs and resource plans. In turn, the flaw impacts the resulting allocation of costs to seasons, times of day and classes. As a result of the Company's proposal, society's scarce resources appear misallocated, MDU's future costs are not minimized, and cross subsidies take place between classes. While the below criticisms are directed at MDU, they equally apply to MCC's testimony (see Exh. MCC-2, and Data Response No. PSC-MCC40). The following discusses these concerns.

285. From MDU's testimony (Exh. H, JKC-7), the trend in relative seasonal and time-of-day loss of load hours (LOLHs) is provided. On one hand there is no significant change in relative

total on- and off-peak LOLHs. However, there are trends in LOLHs masked by the simplistic summation of total on- and off-peak LOLHs. First, the summation of total summer LOLHs declines from year 1982 to year 1987: the average of five historic years of LOLHs does not capture any possible trend during the relevant time period which is, assumedly, about 1986 to 2001 based on MDU's calculation of real levelized Sch. H costs. If the total summer LOLHs are declining, it follows the total winter LOLHs must rise.

286. To be more specific, the trend in summer on-peak LOLHs reflects a clear decline. The 1987 on-peak LOLHs are 43 percent of the 1982 on-peak LOLHs. The summer off-peak LOLHs similarly decline. The winter LOLHs show a converse trend.

287. The MCC's defense for adopting MDU's LOLHs is a non sequitur (see Data Response No. PSC-MCC45). The MCC argues for gradualism in developing seasonal allocations, add makes a slight change in the LOLHs used in this docket relative to the previous docket (75/25 versus 70/30). What is sorely needed is an update of the calculation of LOLHs to see if the recent trend and MCC's gradual move is even a move in the right direction.

288. For the time being, and assuming MDU's LOLHs are accurate, one may question what the impact is of averaging historic LOLH values instead of capturing the future trend. For one, irrigators would appear, to the Commission, to be allocated an uneconomic share of associated capacity costs. It appears more capacity costs should be allocated to the winter season, if one just looks at MDU's LOLH's provided in this docket. As another example, there also is MDU's finding that private lighting should receive no revenue requirement increase. The Commission questions the accuracy of this finding given the relatively and recently higher LOLH's (forecast) in the winter off-peak period (relative and higher to the average). But the Commission questions whether MDU's LOLH's, regardless of accuracy, are even applicable for allocating certain costs to seasons.

289. The Commission is puzzled by the above discussed trend in LOLHs on one hand, which is to reduce the summer LOLHs relative to the winter, and MDU's projected "summer only" purchases of MAPP Sch. B and H (energy and capacity) on the other hand (see MDU Data Response No. PSC-138). In the Commission's estimation, MDU's proposed use of LOLH's to allocate

generation capacity costs (MAPP Sch. H) based on the summation of seasonal on and off-peak LOLHs is highly questionable. MDU is only projecting summer purchases of Sch. H, so why allocate a portion of the same costs to the winter? In fact, MDU must contract separately for summer purchases of Sch. H capacity (see MCC Data Response No. PSC-MCC39-h). On this basis, there appears to the Commission a logical basis to allocate all Sch. H purchase costs to time periods in the summer season only. MDU must address this issue in its next electric docket. There still appears merit in using accurate LOLH estimates with incremental transmission costs.

290. In summary then, the Commission's concern is twofold. First, the use of historic average LOLHs, versus recent and forecast appears to move cost responsibility and prices in the wrong direction. As an analogy, we now know that the Company's proposed use of running costs from the MARGIN program in Docket No. 83.9.68 was in error (see MDU Response No. 37 to the Commission staff). It appears to the Commission that MDU's LOLH proposal in this docket is similarly flawed and will result in the "highly volatile" marginal cost revenue requirements that the Company has been critical of and would also want to avoid (see MDU Data Response No. PSC-42).

291. Second, the use of LOLH's does not even seem appropriate for allocating summer only purchases of Schedule H generation capacity, except possibly to times of day in the summer. As a separate issue, and again based on MDU's summer only forecast purchases of MAPP Schedule B energy/capacity, it appears to the Commission logical to allocate the same costs to just the summer season, or some portion there of. As a result of the above, it in turn appears time for MDU to consider tariffing seasonal price differentials.

PART H

RECONCILIATION

292. The use of a marginal costs to develop class revenue requirements involves a reconciliation step. This is because the revenues from marginal cost pricing normally differ from the allowed revenue requirement. Approaches used to reconcile cost based prices and allowed revenues run the gamut from "equal percent" changes to "inverse-elasticity" pricing. Inverse-elasticity pricing may take place on an intra- and/or inter-class basis.

293. The equal-percent approach, when applied to total class revenue requirements, is relatively blind to market impacts. After the uniform percent increase is applied at the class level, recognition of relative marginal costs for the various intra-class products may mitigate adverse market impacts i.e., a nonuniform percent increase or inverse-elasticity pricing may be used on an intra-class basis.

MDU's Reconciliation

294. In electric Docket No. 83.9.68, MDU proposed an equal-percent reconciliation using total long-run marginal costs (see Finding No. 201 of Order No. 5036a). In the instant docket, MDU proposed a different approach.

295. The Company's reconciliation approach in this docket involves a multi-step process (see Data Response Nos. PSC-12 and PSC-42). First, the Company's revenue target, net of customer costs, is divided by the sum of each class' marginal cost revenue requirements, also net of customer costs. The resulting percent is, in turn, multiplied times each customer class' marginal cost revenue requirement. The result is added to class specific customer costs.

296. In the second step, MDU applied the "overall percentage increase requested" to each class. That is, the ratio of the final proposed revenue requirement divided by the existing revenue requirement was used to inflate each class' existing level of revenue generation.

297. In the third step, MDU averages the results from the previous two steps. The final step involved constraining the impacts of the first three steps; the imposed constraint is that no class receive an increase greater than one and one-half (1.5) times the overall sales revenue percent increase e.g., if the overall percent increase was 10 percent, then no class, regardless of cost study results, would receive greater than a 15 percent increase.

MCC's Reconciliation

298. MCC's reconciliation approach appears nearly identical to its Docket No. 83.9.68 proposal. MCC's "reassignment" of costs of power production from the demand component,

calculated on an average embedded basis, to the energy component, is also the MCC's reconciliation proposal (see, in order, Exh. MCC-2, p. 45, TR 118-119, and finally Exh. MCC-2, p. 53).

299. MCC's reconciliation approach operates as follows (for detail see Exh. MCC-2, Exh. JD-2, p. 1 or 2). First, MCC functionalizes MDU's embedded revenue requirement, with any increases, by BPSCs and non-BPSCs. Second, MCC computes the functionalized marginal cost of service. The non-BPSCs are equal in the embedded and marginal cost revenue requirements, but vary with the assumed final approved revenue requirement. In order to equalize the marginal and embedded revenue requirements, MCC applied a uniform percent increase to all components of the BPSCs.

300. Thus, with Mr. Clark's proposed final revenue requirement, the MCC's marginal cost revenue requirements (BPSCs) must be increased by over 140 percent. With MDU's proposed final revenue requirement, the MCC must inflate the BPSCs by over 180 percent of estimated marginal costs. MCC holds that this reconciliation approach is "...one non-discriminatory way to meet the revenue target allowed by the Commission..."

301. MCC, like MDU, also includes a constraint to modify rate impacts (the following is obtained from Exh. MCC-2, p. 6, and Data Response No. PSC-MCC31). Once the MCC has its class revenue requirements in hand, a four-step process is used to modify rate impacts. In this four-step process, the MCC splits customer classes into three groups. The first group is of classes for which, according to MCC, a revenue reduction could be justified. The second group is of customer classes whose percent revenue increase is positive, but less than two times the overall percent increase that results from Mr. Clark's testimony. The third group is all other classes.

302. With these three groups, MCC proposes the following rate moderation measures. First, no class should receive a revenue requirement decrease. The second group's revenue requirement increase would be that which resulted from the C0S study. Finally, any residual revenue requirement should be recovered from all other classes.

Commission Decisions On Reconciliation

303. For the below reasons, the Commission disagrees with MDU's and MCC's reconciliation measures as proposed in this docket. The Commission's preferred approach applies the method used in the last MDU electric docket (Docket No. 83.9.68) which, in turn, was MDU's proposal at the time.

304. One similarity between the MDU and MCC reconciliation approaches should be noted. The similarity reflects what the Commission would call an inverse "inverse-elasticity" rule. This similarity points out a difference in degree, but not in kind, in each party's preferred reconciliation approach. The similarity is that each party argues to equate the final revenue requirement to the marginal cost revenue requirement by increasing the marginal cost revenue requirements for all classes to equal the final revenue requirement, net of certain costs. The parties part ways on the relevant costs that should first be removed from the final revenue requirement e.g., customer or customer and distribution. That is, in a Venn diagram sense, the parties disagree on the definition of relevant marginal costs that are to be reconciled. Problems with each party's approach are discussed in the following.

305. With regard to MDU's reconciliation method, the Commission has two principle concerns. The first has to do with the exclusion of marginal customer costs from the costs to be reconciled. The second has to do with MDU's averaging of the marginal cost revenue requirement with the "overall percentage increase." Both are discussed in detail below. The latter concern illuminates the underlying interstate allocation of certain costs. As a result of MDU's use of a twelve (12) CP allocator for certain costs, the Commission holds that each state is, in turn, allocated an uneconomic share of the same costs. This issue, in turn, relates to MDU's projected <u>summer</u> <u>only</u> incremental purchases of energy and capacity from MAPP.

306. With the first issue, the Commission's position is unchanged from the last docket. MDU is to take the total final approved revenue requirement from this docket and divide this amount by the total Company (Montana) marginal cost based revenue requirement (see Order No. 5036a, p.81). The resulting ratio is to be applied to each class' marginal cost revenue requirement. Revenue impact moderation measures are as follows.

307. The Commission finds that no class should receive a revenue requirement increase in excess of 113 percent of the their pro forma revenue requirement. Any LRIC allocations in excess of 113 percent must be reapportioned to other classes. This is less than the maximum percent increase proposed by MDU and associated with the Company's final proposed revenue increase relative to pre-interim levels. This Commission finds this lower limit on increases prudent given the noted concerns with LOLHs and seasonal cost allocation.

308. While the Commission does not seek changes in this docket, the second issue remains of interest to the Commission as it makes the connection between MDU's interstate allocation of costs (the jurisdictional separation study), the Company's embedded cost-of-service study and efficiency in resource allocation. To begin the discussion, Mr. Castleberry states that it is "...inappropriate to use marginal costs at all in the establishment of class revenue requirements..." because the "...class revenue requirements resulting from my marginal cost-based three-step process of revenue apportionment are not significantly different from the results I would have obtained under my normal (comparable) embedded cost-based procedure" (Exh. H, p. 10).

309. Then, according to Mr. Castleberry, it is Mr. Don Ball's cost studies (in part Statements L & M) that are his preferred basis for determining class revenue requirements Exh. H, p. 3). From Mr. Ball's direct testimony it is clear that capacity costs, including MAPP capacity purchases, assumedly Sch. B and H, of energy and capacity, are allocated, in part, to the states on the basis of the sum of the monthly coincident peak loads in each state (see pp. 6 & 7 of Mr. Ball's direct). Herein lies the crux of the Commission's problem with MDU's reconciliation approach.

310. The Commission finds that MDU's use of an average of the sum of twelve coincident peaks to allocate certain types of capacity and energy revenue requirements results in both inefficient resource allocation and the State of Montana very likely being allocated an uneconomic share of the associated costs. As a result, MDU's reconciliation approach, which averages the impacts of the increased revenue requirement based on MDU's embedded cost study with the marginal cost study results, is improper. The following explains the basis for the Commission's position.

311. From MDU's data response to the Commission staff (No. PSC-138), it is clear that for years 1987 through 1996, MDU is only planning MAPP capacity purchases (Sch. B and H) in

the "Summer" season. In turn, MDU's apparent summer season definition is May through October inclusive. Next, from Mr. Ball's Exh. DRB-4, it is clear MDU's system has bimodal peaks. However, it is also clear that recent and projected system summer peaks exceed the related winter peaks. That the projected summer peaks exceed the projected system winter peaks by less than five percent, yet the same relationship results in projections of summer only purchases, is somewhat puzzling. In any case, it is MDU's allocation of capacity related revenue requirements on a twelve CP basis, when it is clearly evident that summer system peak loads drive the need for additional energy and capacity purchases, that troubles the Commission.

112. In the Commission's estimation, a more efficient revenue requirement allocator would appear based on some sort of average of relevant summer peaks, which may only be two or three months. Because the Montana portion of the system peaks in the winter, relative to the states of North and South Dakota, Montana's allocation of capacity and energy cost type revenue requirements would likely decrease. The Company is forewarned that the Commission intends to explore this issue in MDU's next electric docket. The intent is to improve upon the efficiency of use of scarce resources.

313. The Commission is also troubled by MCC's reconciliation approach. MCC, like MDU, simply inflates the most important portion of the cost of service study to reconcile final and marginal cost revenue requirements. The MCC's inflation factor exceeds MDU's because MCC excludes more costs than MDU from the relevant marginal cost revenue requirement. As with MDU's proposal, this appears to be an application of inverse "inverse-elasticity" pricing.

314. To repeat the Commission's objection from the last MDU electric docket, the Commission finds "The MCC's proposal to reconcile just Bulk Power costs does not work to maximize welfare...Clearly, the elasticity of demand is relatively larger for the energy and demand components of Bulk Power costs than for, say, customer costs...It follows that, from an economic viewpoint, one would attempt to minimize deviations from Bulk Power costs relative to say, customer costs." (Order No. 5036a, Finding No. 203).

PART I

RATE DESIGN/PRICING

315. Introduction. In this docket, MDU has proposed sweeping tariff, rate design and price changes. The MCC also testified on pricing issues. Following this introduction, the Commission will review the parties' pricing philosophies. Next, the parties' pricing proposals on a "class-by-class" basis are reviewed, followed by the Commission's decisions.

316. It is useful to organize the proposed tariff and price changes into three groups: 1) trivial renumbering; 2) tariff expansion/contraction with a shifting of billing determinants e.g., customers, kwhs etc., between tariffs; and 3) structural changes within a class e.g., declining-block structures. These categories are not necessarily mutually exclusive. The below Table compares the existing and proposed tariffs. It should be noted that while the MCC concurs with MDU's proposal to 1) renumber tariffs, and 2) to expand/contract certain tariffs, it does not concur with all of MDU's proposed pricing changes.

Table 4
A Comparison of Existing and Proposed Tariffs

Existing		Proposed	
Class	Rate	Class	Rate
Residential	10	Residential	10
Residential (OTOD)	16	Residential Dual Fuel	11
General Elec. (ND)	20	Residential (OTOD)	16
General Elec. (D)	22	Small Gen. Elec. (D & ND)	20
General Elec. (OTOD/ND)	23	General Elec Dual Fuel	22
Private Light	24	Irrigation (OTOD)	24
Irrigation	25	Irrigation	25
General Elec. (OTOD/D)	26	Small Gen. Elec. (OTOD)	26
Feed Grind	27	Feed Grind	27
Industrial (TOD)	30	Large Gen. Elec. (D)	30
Irrigation (OTOD)	35	Large Gen. Elec. (OTOD)	31
Municipal Light.	41	Gen. E High Load Fac. (D)	32
Municipal Pump.	48	Gen. E. (OTOD)	33
Residential Dual Fuel	53	Lighting Service	41
General Elec. Dual Fuel	54	Municipal Pump.	48
		Private Light.	52

Explanations: 1) Time of Day (TOD); 2) Optional TOD (OTOD); 3) Demand (D); 4) Non-D (ND).

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317. Pricing Philosophies. Each tariff has one or more products or elements that may be priced to recover the associated class' revenue requirement. For example, lighting tariffs typically have one price element. The residential tariff has two elements: 1) the commodity price, c/kwh, and 2) access price, $/month. Other classes have separate products and prices for e.g., energy, demand, reactive power and access.

318. Then, the key pricing issue boils down to the criteria used to set the various prices on each tariff. A partial list of relevant pricing objectives/criteria would include cost based pricing and moderation of price impacts. Typically, the two criteria can not be simultaneously achieved, resulting in tradeoffs.

319. MDU. MDU's stated pricing philosophy recognizes and attempts to balance the numerous and sometimes conflicting ratemaking objectives. Within a customer class, MDU stated its support for a pricing theory that discourages the wasteful use of resources and encourages economically efficient uses. MDU also noted that, on a relative basis, the elasticity of demand for access is the least elastic rate element (see MDU Data Response No. PSC-141).

320. MCC. MCC's stated pricing philosophy also appears founded on economic efficiency grounds. A summary of MCC's pricing philosophy follows:

> The public interest is not served by a pricing policy that encourages additional electric sales from which the benefit derived is less than the cost incurred in the provision of such additional sale (Exh. MCC-2, p. 19).

321. In addition, the MCC provided a detailed response to a request to discuss relative elasticities of demand for the several potential products (access, energy and capacity), and on both an intra- and inter-class basis. The MCC relates relative elasticities of demand to factors such as load factor and customer size (assumedly, level of energy demand) but with a strong "other things being equal" assumption (see Data Response No. PSC-MCC60). MCC, while not disagreeing with MDU, did not state that there is a relative elasticity of demand difference between e.g., access and energy.

MCC, that is, appears to focus on an individual's, and not a class' (an aggregation of individuals'), perspective.

322. In designing prices, the MCC states that energy charges were computed residually on those tariffs with energy and demand price elements (see PSC-MCC33-c).

323. Commission. The Commission's pricing philosophy in this docket, as with other dockets, attempts to achieve cost and allocative efficiency objectives. In designing prices, the Commission continues to hold that the product for which the elasticity of demand is greatest should be priced as near to marginal cost as possible. As necessary, other prices will be computed residually taking into account rate impacts. In this regard, the Commission concurs with MDU in that, on average and on an intra-class basis, the elasticity of demand (in, of course, absolute value terms) for the products energy and capacity exceeds that for access (customer related).

324. In order to achieve cost and allocative efficiency objectives, prices need to be set as close to cost as possible. In turn, and as discussed above, there appears strong evidence challenging MDU's and MCC's exclusion of seasonal cost and price differences. In light of MDU's resource plans, the MCC's position that there is no seasonal cost variation appears unfounded (see Data Response No. PSC-MCC40). This evidence raises a concern, on the Commission's part, for making major rate design changes in this docket. The Commission will remain skeptical of any rate design proposals by either party until the apparent seasonal cost issue (which includes the above LOLH issue) is resolved. The Commission will not require seasonal price differences out of this docket. The issue of seasonal cost-based prices will be a central concern of the Commission's in MDU's next electric docket, unless raised sooner by MDU.

325. The following attempts to review the current and proposed prices for MDU's various customer classes. The review is limited somewhat by the fact that some of the new classes do not have precursors. Another complexity that limits a comparison is the difference in revenue requirements: Existing tariffs reflect an interim increase and the final tariffs will reflect, in part, a final higher revenue requirement.

Residential: Rate 10

326. The current interim tariff features a $3.00/month Base Rate and a 7.584c/kwh energy charge. There are no complex mapping issues with this tariff. The issues are strictly rate design related.

327. <u>MDU</u>. MDU's final proposal is a $3.00/month Base Rate and a three-step declining-block rate structure. The first rate applies to the first 450kwh/month; the second, for the next 300kwh, and the third for demand in excess of 750kwh/month. The difference between the first and second blocks reflects customer costs uncollected in the Base Rate. The second differential reflects "informed judgement" (see MDU Data Response No. 30 to the PSC).

328. <u>MCC</u>. MCC's proposed rate design features a $3.00/month Base Rate and a <u>flat</u> annual commodity price. MCC holds that "the small differences in marginal energy costs and seasonal load patterns suggests that the Company's justification for the declining block rates (sic) need to reflect the different cost characteristics of space heating customers was not supported by the evidence" (Data Response No. PSC-MCC46-f).

329. <u>Commission</u>. MDU's declining-block price proposal has raised a complex issue. It has been about six years (May, 1981) since this class has had a declining-block rate structure. In the past, the Commission has applied PURPA's economic cost test to analyze the merit of declining-block prices. Since 1981, MDU's residential rates have been flattened, inverted and then flattened again, in that order.

330. The Commission would note that the justification for inverted-block prices also applies to declining-block prices: Factual long term marginal cost evidence must support the Commissions choice of one or the other. The Commission has followed this policy in the past. See, for example, Docket No. 6655, Order No. 4635c, Finding of Fact No. 69 and Docket No. Order No. 5113b, Finding Nos. 134 for a reiteration of the Commission's longstanding cost criterion for tariffing declining-block prices. As an additional example, the Commission eliminated the residential inverted-block price structure, in MDU's most recent gas docket, based on the Company's reference to the same Commission logic used to tariff an inverted-block price structure for gas (see Finding of Fact No. 151 in Order No. 5160a and Mr. John Castleberry's direct testimony at page 24, both in Docket No. 85.7.30).

331. The Commission will approve a declining-block price structure if, and only if, it is justified as cost efficient using long-run marginal costs. To do otherwise would be inconsistent with previous Commission orders.

332. The Commission disagrees with MDU's proposal and MCC's criticism of MDU's proposal. The following reviews, in turn, several optional rate designs, and the Commission's concerns with MDU's and MCC's positions.

333. With certain assumptions, one can compute alternative rate designs. First, assuming the final revenue requirement for this class equals about $11,700,000 and the existing $3.00 Base Rate, a flat commodity price will equal about 7.74/kwh. Even if the Base Rate is doubled to $6.00, the commodity price only falls to about 7.24/kwh. Then, with the current rate design, it is not possible to lower the average price down to either MDU's or MCC'S relevant floor marginal cost (discussed below) without a substantial Base Rate increase.

334. Even if the Commission did not have concerns with certain aspects of the parties' cost studies, MDU's rate design proposal is too drastic a price change for one docket. Just as inverted-block prices have been slowly implemented in the past, declining-block prices should be slowly implemented, if justified by long term marginal costs. If at this time a declining-block were cost justified, a two-step declining-block (TSDB) would be sufficient to move prices in the right direction at this time.

335. Then, and as an example only, given the above $11,700,000 revenue requirement and a $3.00 Base Rate, a TSBD structure with a one (1) cent/kwh differential and a 750 kwh break point results in the following prices. The initial-block price (IBP) equals about 7.94/kwh and the tail-block price (TBP) equals about 6.94/kwh. Just a two mill increase in the IBP allows an eight mill decrease in the TBP.

336. Two relevant questions arise with regard to this exercise. First, how low could the TBP go (the "floor" value) and still exceed <u>all</u> relevant marginal costs? Second, if there is an elasticity response, should it be reflected in prices?

337. With regard to the first question, MDU and MCC provided late-filed exhibits (LFEs) with floor costs of 6.2124/kwh and 3.9674/kwh respectively. Given each party's pricing philosophy,

one would not price below the floor value. Each floor value, in turn, reflects the same party's preferred COS study approach, neither of which, in total, was accepted by the Commission or reflective of January 1, 1988 dollars. Based on the Commission's COS decisions, and ignoring any seasonal cost concerns, a comparable floor equals about 3.64/kwh (assuming LOLH weighted average generation and transmission costs combined with distribution costs spread evenly to each of 8,760 hours).

338. When the Commission's seasonal cost concern is factored into the development of a floor price, there appears no economic merit in a declining-block rate structure because the evidence does not establish that declining-block rates are justified by long run marginal costs. This result rests on the following assumption and calculations. The critical assumption is that one would not want the annual average tail-block price to fall below the summer on-peak cost. While average-cost pricing is unavoidable, this assumption rests on the philosophy that it is uneconomic to encourage on-peak summer consumption with prices less than cost.

339. Then, based on the Commission's calculation, the on-peak summer cost is over 84/kwh. This value exceeds the current flat commodity price, let alone the above discussed floors, and if one accepts the basis for the above assumption, argues against a declining-block price structure. Table 5 provides the calculation.

Table 5
Cost-Based Residential Floor Price
Assuming Seasonal Costs

Cost Component	Value 4/kwh
Generation Energy:	
Fuel	1.577
Baseload Capacity	5.007
Generation Peak Capacity:	0.940
Transmission Capacity:	0.153
Distribution Capacity:	0.546
Total:	8.2234/kwh

Source: The cost date used in these calculations derived from MDU's February 20, 1987, letter to the Commission. This letter, in turn, was in response to a late-filed exhibit request and reflected certain Commission draft cost of service decisions that are now final. The decisions, in turn, reflect a mix of MDU's and MCC's proposals, combined with certain Commission changes e.g., 1/1/88 dollars.

The assumptions used follow. The 1.5774/kwh value is MDU's calculation of real levelized fuel costs using four years of data and in 1988 dollars. The 5.0074/kwh value is the $91.38/kw Base Peak cost of Sch. B capacity allocated to just the summer on-peak hours. In this allocation MDU's total on-peak hours of 3,650 were assumed to derive 50/50 from the summer and winter seasons.

Generation capacity costs of 0.944/kwh derive from the $17.12/kw in 1/1/88 dollars spread to just summer on-peak hours.

Transmission capacity costs of $5.57/kw were allocated to all 3,650 on-peak hours in this year.

Distribution capacity costs of $47.80/kw were spread to 8,760 hours per year.

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340. If the summer season were narrower than six months, then certain of the above cost components would increase even more. On the other hand, if certain of the Schedule B costs can be casually related to the off-peak summer hours, the 8.24/kwh value would decrease. Until the Commission's concerns on the seasonal cost issue are resolved, a flat annual price will be tariffed. For information purposes, the Commission does request MDU to provide, in its compliance workpapers, a summary breakdown of the on- and off-peak hours, LOLHs and marginal costs system lambdas from the EGC) by season and for the test year.

341. In summary, the Commission finds that MDU must maintain the current rate design. To sum up the Commission's reasoning for making no major changes, the Commission firmly believes there is cause for concern in both MDU's and MCC's cost of service studies. The cause for concern stems from the LOLH's used by the parties, and the failure to allocate projected increased MAPP purchase costs to the apparent cost causers, which appear to be largely summer customers.

342. This discussion would not be complete without a comment on MCC's basis for rejecting MDU's declining-block proposal. As noted above, MCC's basis is that small differences in MDU's marginal energy costs and seasonal load patterns do not support MDU's need to design

a tariff to accommodate space heating customers (MCC Data Response No. PSC-MCC46-f). This basis conflicts with MCC's own stated pricing philosophy quoted above. A logical corollary of MCC's stated philosophy is:

> The public interest is not served by a pricing policy that discourages additional electric sales from which the benefit derived is greater than the cost incurred in the provision of such additional sales.

343. MDU is directed, then, to set a Base Rate of $4.50 per month with the remaining revenue recovered from the commodity price on a 4/kwh basis. The resulting commodity price will be around 7.54/kwh.

Optional Dual Fuel: Rates 11 and 22

344. Because of the similarity of issues involved, these two optional tariffs will be addressed at the same time. These tariffs were initially approved by the Commission in Docket No. 84.12.83 (Default Order No. 5125). MDU's test period excludes billing units for these tariffs. As of September 1986, there were only nine Rate 11 and zero Rate 22 subscriptions (see MDU Late Filed Exh. 2). MDU's proposal involves more than a simple mapping/changing of tariff numbers.

345. MDU. MDU proposed to renumber existing Rates 53 and 54 as Rates 11 and 22 respectively. MDU also proposed to raise the Base Rate and lower the energy price on Rate 11. On Rate 22, MDU proposed several changes. First, to bifurcate the existing flat Base Rate on the basis of phase of service. The single phase Base Rate would decrease and the three phase Base Rate would increase. MDU proposes to lower the energy prices for both phases of service. Second, the revenue requirement constraint was expanded to include three proposed tariffs.

346. MCC. MCC's comments on Rates 11 and 22 were largely concerned with the magnitude of the interruptible credit. MCC's concern is that the "proposed rates for customers with energy charges fifty percent lower than the comparable firm service rates do not seem justified given the somewhat lower marginal cost of capacity" (Data Response No. PSC-MCC59). MCC agrees with the narrower peak period for the dual-fuel tariffs, relative to the time-of-day tariffs (TR 116).

347. Commission. The apparent revenue constraint in developing dual fuel prices varies depending on the dual fuel tariff. First, on Rate 11, the constraint is the revenue requirement for the

otherwise applicable residential tariff (e.g., see MDU Data Response Nos. PSC-52 & 53). Given this constraint, the Commission finds that the key concern is for the commodity price on Rate 11 to cover all relevant marginal costs. Remaining revenue requirements must be collected from the Base Rate.

348. Second, with Dual Fuel Rate 22, the Commission has several concerns. First, MDU appears to use a combined revenue requirement constraint, for three proposed customer classes (proposed Rates 20, 30 and 32), to compute Rate 22 energy and Base Rate prices in the instant docket. The existing "CONTRACT TERMS" section of Rate 54, however, allows a general electric customer on either of MDU's two General Electric tariffs (existing Rates 20 and 22) to take service on Rate 54. In relevant part, this section reads: "At the end of a one-year period...or of returning to <u>one</u> <u>of</u> <u>the</u> regular General Electric Service Rate..." (emphasis added). While not indicated in the "Rates Reflecting Proposed Changes" section of Appendix C, MDU has changed the above emphasized language to refer to the "applicable" rate. But, can Rate 22 efficiently reflect several classes' combined revenue requirements?

349. The Commission finds MDU must compute Rate 22 prices based on marginal costs for the following reasons. This finding requires no revenue requirement constraint except that prices do not fall below marginal costs. First, given MDU's own "heterogeneity" argument for separate General Electric rates, it would appear necessary to have separate Dual Fuel rates for each of the Small GE, Large GE and High Load Factor GE, instead of an average Dual Fuel rate for all three classes. Second, MDU's own argument that the High Load Factor customers have unshiftable loads argues for excluding Rate 32 from any average Dual Fuel rate in any case. Third, MDU's proposed prices with MDU's own higher assumed final revenue requirement do not appear to cover the Commission's determined marginal energy cost, not to mention certain demand costs the MCC holds are not avoided. Also, and as discussed later, the Commission has not found merit in MDU's proposal to eliminate the current Mandatory Industrial TOD rate. The Commission has other concerns and comments on MDU's Dual Fuel rate proposals.

350. MDU's "super-peak" period appears well-defined based on a visual analysis of test year monthly peaks (Exh. H, JXC-6, pp. 1-12). The 5:00 P.M. to 9:00 P.M. super-peak period

captures the monthly peaks during the summer months of June, July and August. In addition, the same super-peak period captures the winter peaks in the months of November through January. The Commission has two concerns with this data, however.

351. First, the use of this, assumedly, historic actual data is only valid if the forecast peaks occur in the super-peak periods. Also, the super-peak period fails to capture the peak load period in three of six summer months. MDU must demonstrate in its compliance work papers that the inability of the super-peak" period to capture the peak load in all summer months is immaterial and/or incorrect when one turns to forecast data. Final tariffs will not be approved until this and other noted requests are answered by MDU.

352. Second, the Commission finds an apparent anomaly from a visual inspection of the above-cited cost-and load data. Page 7 of 12 of JKC-6 provides an example. The anomaly is the inexplicable inverse relation between peak load (at hour 18) and marginal energy cost: Marginal energy cost is near its lowest when load peaks. The Commission also requests an explanation of this anomaly in MDU's compliance work papers.

353. In terms of pricing, MCC's concern that the interruptible discount is too great appears economically sound. In the case of Rate 11, the only avoided costs that should be netted from the otherwise applicable Rate 10 floor commodity price are the costs allocated to just the "super-peak" hours. The excluded costs should, at most, include $19.21/kw for Sch. H and the associated fuel costs allocated to the "super-peak" hours i.e., running costs and the associated hourly energy cost of Sch. B purchases.

354. The Commission approves MDU's dual fuel tariffs with reflection of the MCC's concern for reducing the interruptible discount in the calculation of marginal cost based floor commodity prices on each rate. Prices on Rate 11 must reflect MDU's proposed Rate 10 revenue requirement, MCC's concern and the Commission's cost decisions. Prices on Rate 22 must also reflect the MCC's concern and the cost results from this order. A final comment with regard to Rate 11 follows.

355. From an allocative efficiency standpoint, the Commission has concern with MDU's employees taking service on Rate 11. If a commodity price is not set sufficiently above marginal cost

so that the discounted price still exceeds marginal cost, employee type consumers may be lead to make uneconomic resource consumption decisions. In the case of PP&L's Clean Air/Winter Saver tariff, the Company acknowledged the same concern and effectively disallowed employees from receiving the discount. The Commission expects to visit this concern from a revenue requirement and allocative efficiency standpoint in MDU's next electric rate case.

<u>Residential Optional Time-Of-Day: Rate 16</u>

356. The current optional residential TOD tariff includes a $3.00 Base Rate and on-peak (11.307c/kwh) and off-peak (5.654c/kwh) energy prices. The current on- to off-peak differential (ratio) is 2.0:1.

357. <u>MDU</u>. MDU's final proposed rates include a $6.50 Base Rate and on- and off-peak commodity prices of 13.686c/kwh and 4.277c/kwh respectively, for a 3.20:1.0 ratio. MDU uses the Rate 10 revenue requirement, with an adjustment for increased meter costs, as the revenue constraint in designing Rate 16.

358. <u>MCC</u>. MCC's proposal also includes a revenue constraint, MDU 's $6.50 Base Rate and MDU's 3.20:1.0 ratio. Thus, the revenue requirement drives the level of the on- and off-peak commodity prices given agreement with MDU's on- off-peak ratio constraint and the Base Rate constraint.

359. <u>Commission</u>. As in MDU's last electric docket, the issue of optimal optional TOD rates once more appears controversial. The following sets forth how prices on Rate 16 must be computed. First, the parties' proposal to impose the Rate 10 revenue requirement as a constraint, adjusted by the additional meter costs, is accepted. Next, marginal cost based on- and off-peak commodity prices must be computed.

360. Clearly, only by coincidence will MDU's and MCC's objective of tariffing a 3.20:1.0 price ratio jibe with the result of setting marginal cost based prices on this optional tariff. By setting the Base Rate first and then requiring a 3.2:1.0 ratio in on- off-peak commodity prices could generate uneconomic commodity prices. The 3.2:1.0 ratio proposed by both parties does not appear economic based on cost evidence in this docket. Examples follow to support this claim.

361. First, if MDU's on- and off-peak costs are increased equally by 1.04c/kwh, to reflect the Sch. B energy cost, the Company's cost-based ratio falls to 2.6:1.0 (see MDU Data Response No. PSC-54, p. 6 and MDU's Late Filed Exh. 1). As an aside, it would be interesting to know the impact on optional seasonal TOD prices of attributing Sch. H and B costs to just the summer months. Second, MCC's cost-based floor on- and off-peak prices, before any adjustment for Sch. B energy costs, equals 1.5:1.0 (see MCC's Late Filed Exh. 1). After adding Sch. B energy costs to the MCC's floor on- and off-peak costs, MCC's ratio falls to 1.12:1.0. Neither of the above lower ratios reflect the Commission's adopted COS study.

362. Two limits within which Rate 16 prices may be set, assuming a revenue requirement constraint on rate design, include the following. One limit would be to tariff cost-based commodity prices, with any remaining revenue requirement collected in the Base Rate. The other extreme entails setting a marginal cost Base Rate with any remaining revenue requirement collected in the commodity prices. The historic price basis for this tariff and MDU's and MCC's proposals in the current docket, appear more closely related to the latter limit. Moreover, this approach has resulted in zero customer participation.

363. With the Commission's COS study decisions, and using the former option, the on- and off-peak commodity prices would equal about 3.99c/kwh and 3.55c/kwh for a 1.12:1.0 ratio (assuming generation and transmission demand costs are recovered with MDU's on- and off-peak LOLHs, distribution demand costs are evenly recovered from each hour and 3.15c/kwh on-peak and 2.71c/kwh off-peak energy costs). The Base Rate would have to recover the remaining estimated Rate 10 revenue requirement of about $7,324,649 ($11,700,000 plus $903,679 increased meter costs less $5,278,944 from the commodity prices). Then, the resulting Base Rate would, however, have to rise to about$30.00/month. Because this is an <u>optional</u> and not mandatory tariff, the Commission's normal rate impact concerns do not exist: Customers will only subscribe on a <u>voluntary</u> basis, and at present MDU has no Rate 16 customers.

364. MDU is to tariff, with any necessary modifications e.g., a moderated revenue requirement, the above-discussed prices. And just as MDU has promoted the dual fuel tariffs with advertisements, MDU should do the same with Rate 16 (see MDU's Late Filed Exh. 13). The

Commission would, if the necessary data existed, also include seasonal prices on this optional tariff. Such refinements can await MDU's next docket. MDU should require a one-year minimum subscription to Rate 16. Any associated revenue requirement concern can be addressed in whatever fashion MDU would have addressed the same concern, had it arose, with the current tariff. To reiterate, the Commission's above noted concern with employees taking Dual Fuel service equally applies with this optional optimal TOD tariff.

General Electric: Proposed rates 20, 30, 32 and 33

365. At present, MDU has demand and non-demand metered General Electric (GE) tariffs (Rates 22 and 20). In addition, MDU has a Mandatory Industrial time-of-day (TOD) tariff, Rate 30. Optional TOD and dual fuel tariffs also exist for the former two general electric current tariffs. The current non-demand metered tariff features a $5.65 Base Rate and a 6.033c/kwh commodity price. The current non-demand metered tariff features: 1) a $10.00 Base Rate, 2) a $3.42/kw demand price (for demand in excess of 5 kw) and 3) voltage level energy prices of 4.397c/kwh (primary) and 4.628 (secondary). The current mandatory TOD tariff, Rate 30, features: 1) a $40.00 Base Rate, and, 2) a flat $7.30/kw demand charge and voltage level differentiated TOD energy prices.

Mapping and Expansion/Contraction Changes

366. MDU. Because of MDU's complex mapping, rate design and tariff expansion/contraction proposals, two levels of Commission decisions are required. The first level deals with MDU's proposed tariff expansion add contraction changes. Because these proposals change the current mix of general electric tariffs (20, 22 and 30) to a new mix (20, 30, 32 and 33), these changes must be considered as a package.

367. It is first useful to compare the criteria used to categorize current and proposed customers on MDU's current and proposed tariffs. The criteria used to categorize customers on to one of the three (3) current tariffs involves: 1) a customer distinction (business versus industrial), 2) demand metering comparison, and 3) a voltage level of service distinction (2300 kv).

368. The method used to categorize customers under MDU's four (4) proposed tariffs includes load size (50 kw) and load factor (75 percent) data. The Small General Electric (SGE) tariff (Rate 20) is for customers with less than 50 kw demand and the Large GE (LGE) tariff (Rate 30) is for customers with demand in excess of 50 kw but with a load factor less than 75 percent. The High Load-Factor GE tariff (Rate 32) is for customers with demand in excess of 50 kw and a load factor exceeding 75 percent. The optional TOD tariff (Rate 33), to the High Load Factor GE tariff, has the same qualifying criteria.

369. MCC. MCC concurs with MDU's proposal to replace the current Rates 20, 22 and 30 with Rates 20, 30, 32 and 33. More is said later on the degree of MCC's concurrence with specific MDU price proposals, the second level of issues.

370. Commission. The Commission approves of MDU's SGE/LGE distinction, although the 50 kw criterion seems arbitrary.

371. The Commission, however, finds MDU's proposal to eliminate the existing Industrial mandatory TOD tariff to lack merit for several reasons. Specifically, the Commission feels obligated to rebut MDU's statement that:

> Given the fact that a number of customers served on this rate exhibit extremely high load factors (14 of 23 exceed a 60% annual load factor), it is illogical to apply a mandatory time-of-day rate (Exh. H, p. 26, emphasis added).

372. The Commission's rebuttal follows. First, MDU, in part, argues that load-factor is one factor for deciding upon the merits of mandatory versus optional TOD metering. But then, MDU did not follow-up the use of this criterion with a proposal to retain mandatory TOD pricing for the low-load-factor customers. The Commission's second refutation regards MDU's remark following the above quote:

> This conclusion turns on the fact that a high load factor customer, by definition, has no ability to shift load (ibid, emphasis added).

373. The Commission's second refutation is of this statement in conjunction with MDU's (or MCC's) concern (and the Commission's for that matter) for discouraging the wasteful use of utility service. With MDU's logic, a flat price is superior to TOD prices unless a Customer would "shift" load. But given a flat price is an average price (e.g., across seasons and times of day), when

costs exceed (fall below) the flat price, uneconomic (economic) consumption is encouraged (discouraged): This result runs counter to MDU's (and MCC's) economic efficiency based pricing philosophies. Moreover, it appears, and again based on MDU's logic, that even if incremental metering costs were zero, mandatory TOD prices would not be tariffed, even if with the TOD meters prices could precisely equal costs, and only because load is not shiftable.

374. This second refutation must also address the relationship of a customer's willingness-to-pay relative to price which was so cogently stated in the earlier quoted MCC pricing philosophy. A customer's behavioral response to a price is not limited to just load shifting. A customer's other alternative is to forego (or increase) some or all consumption, if the "benefit derived" falls below (exceeds) the "cost incurred" (see Exh. MCC-2, p. 19). Load shifting may not even be in the cards for a customer. There also is the fact that MDU proposed the existing mandatory TOD schedule in Docket No. 81.1.2.

375. Based on the above, the Commission finds inappropriate the tariffing of the High Load Factor GE tariff (Rate 32) with an optional TOD (Rate 33) counterpart. The existing Mandatory TOD tariff shall remain. Necessarily, MDU will have to replace proposed Rates 32 and 33 with the current mandatory TOD rate in the COS portion of this order. In this regard, the Commission submits another request for MDU to explain the following apparent anomaly.

376. From MDU's testimony (Exh. H, p. 26, lines 4-17) the Company states 14 of 23 current customers have load factors that exceed 60 percent. As an aside, and from MDU's September 12, 1986, interim workpapers, it appears MDU has 21.75 Rate 30 customers. Then, in hearing MDU stated that "...in large measure most of the customers currently served on the mandatory-TOD rate would shift to the non-TOD Rate 32..." (TR 78). As one argument for tariffing the High Load Factor GE tariff, MDU noted heterogeneity as one basis for regrouping customers (Exh. H. p. 24).

377. What is puzzling follows. On what basis are "most" of the customers on current Rate 30 not homogeneous if "most" implicitly have 1) in excess of 50 kw demand, and 2) in excess of a 75 percent load factor, in order to shift to proposed Rate 32? If only 14 of 23 have load factors in excess of 60 percent, how can "most" then "shift to the non-TOD Rate 32" instead of Rate 30?

378. Based on the above, the Commission requests MDU to include in its compliance workpapers a mapping, by customer name and any necessary additional detail, of each customer on current Rate 30 to one or more of MDU's proposed tariffs. In addition, MDU must map backwards the 21 customers included on Rate 32 to show which current tariffs they migrate from, and again referencing specific names.

Rate Design and Prices: Rates 20, 30 and 32

379. First, to avoid confusion between current and proposed tariff numbers, the Commission accepts MDU's proposed numbers for Small GE (Rate 20) and Large GE (Rate 30). But, because the Commission has denied MDU's request to tariff proposed Rates 32 and 33, the current Mandatory TOD tariff (Rate 30) number must be revised. Rate 32 seems practical, and will be used in the following to refer to the Mandatory Industrial TOD tariff.

380. The organization of the review of price proposals for Rates 20, 30 and 39 follows. Rate 20 is reviewed including MDU and MCC price proposals. This is followed by a review of the latter two rates.

Small General Electric: Rate 20

381. MDU. With MDU's final proposed revenue requirement, the Company's proposed rate design includes an $8.00/Month Base Rate, a Minimum Bill that includes the demand prices, voltage level differentiated energy and demand prices and a power factor charge. The demand prices are $4.50/kw secondary (S), and $4.30/kw primary (P) for demand in excess of 10kw per month. The energy prices are structured to be higher for the first 2000 kwh per month than for all kwh consumed in excess of 2000 kwh. The power factor charge is $1.75 per kvar of excess demand.

382. MCC. With a different revenue requirement, MCC adopted MDU's proposed Base Rates and demand charges. MCC also adopts MDU's proposed price structure for pricing energy. The MCC, however, does not appear to approve of MDU's proposal to include demand charges in a "Minimum Bill".

383. Commission. The Commission finds merit in the price structure included on MCC's revised Exh. JD-5 (page 1), with one exception. The MCC does not appear to account for MDU's

kvar charge. The Commission's main concern on this tariff is that the energy prices reflect the adopted cost of service study results in this order. Because this is a new tariff and because of the Commission's concerns with certain COS study results, the Commission finds the following adjustments should be made to the MCC's proposed prices.

384. First, MDU's kvar charge of $1.75 must be included with the class' reconciled revenue requirement, and given no apparent billing units, there is no assumed revenue impact. Second, MCC's proposed energy charges should move (lowered) in the direction of marginal costs indicated in this order. MCC's energy prices should be lowered (with no price below cost) by up to 10 percent followed by equal reductions in the other prices to generate this class' revenue requirement.

385. The Commission has a concern with MDU's proposal to include the demand charge in a minimum bill. First, it is unclear to the Commission precisely how this change is to be interpreted. On one hand, all charges could be in the minimum bill, yet MDU only proposes to put the demand charges in. Given customers are only billed for measured demand, the Commission fails to see the logic for including demand charges and excluding, for example, energy charges. Until better explained, the Commission, consistent with MCC's testimony, denies this proposal.

Large General Electric: Rate 30

386. MDU. Based on the Company's final proposed revenue requirement, MDU proposes the following prices and rate design for Rate 30: 1) a Base Rate of $8.00; 2) voltage level differentiated demand charges equal to $4.30/kw (P) and $4.50/kw (S); 3) voltage level differentiated energy prices that are higher for the first 2,000 kwh than for all additional kwh; and 4) a $1.75 power factor charge.

387. MCC. As with Rate 20, MCC concurs with MDU's proposed Base Rates and demand charges. MCC differs on the following: 1) the class' revenue requirement; 2) the level of energy prices, but not the structure; 3) the inclusion of demand charges in a minimum bill and 4) the inclusion of a power factor charge.

388. Commission. The Commission finds the same criteria used to design Rate 20 prices, as discussed above, should guide the design of Rate 30, and for the same reasons.

Mandatory Industrial TOD: Rate 32

389. MDU. As noted earlier, MDU has not proposed retention of this rate.

390. MCC. Also, as noted earlier, the MCC concurred with MDU's proposal.

391. Commission. Necessarily, the current Rate 30 must be used as a starting point in discussing needed price changes to reflect changed costs and revenue requirements. The Commission finds that in the absence of precise knowledge of this class' revenue requirement, caution must be exercised in the direction given MDU in designing prices.

392. MDU is to follow the below guidelines in designing Rate 32 prices. The class' moderated revenue requirement must be generated from a combination of prices for the current rate design but include a kvar power charge of $1.75. Energy charges should be revised next, to move in the direction of cost of service results in this order, but must not change (increase or decrease) by more than 10 percent. While the current demand charge is flat, MDU may, at its own option, implement a time-differentiated demand price proposal included on the Company's proposed Optional High Load Factor Large TOD tariff. Whatever the Company's decision, the demand, power factor and Base Rate charges must be changed by an equal percent to recover the remaining revenue requirement for this class.

Optional Small and Large General Electric TOD: Rates 26 & 31

393. MDU. Because of the similarities of these two tariffs they will be discussed together. Rate 26 is MDU's proposal for Small GE customers and Rate 31 is for Large GE customers.

394. Based on its final proposed revenue requirement, MDU proposed the following rate design and prices for Rate 26. First, MDU proposed phase of service differentiated Base Rates. Second, MDU proposed time and voltage-level differentiated demand charges. MDU also proposed time and voltage-level differentiated energy charges. The final proposal is for a minimum bill that includes the Base Rate and demand charges.

395. MDU's proposed rate design for Rate 31 is identical to its Rate 26 proposal. While some prices are equal, others differ.

396. MCC. The MCC's proposed rate design for these two new tariffs has certain similarities with MDU's proposals. First, MCC's Base Rate and Demand prices are equal to MDU's on each tariff. While MCC's energy price levels differ from MDU's, the structure is the same. MCC did not include MDU's minimum bill in its proposal.

397. Commission. In designing prices on these two optional TOD tariffs, the Commission finds merit in the general decisions provided above for Rate 16, the optional residential TOD tariff. Energy prices should be set based on the cost of service results in this order, including MDU's and MCC's agreed upon structure. The Base Rate, demand charges and kvar charges should be equally adjusted, as necessary, to recover the remaining revenue requirement on each tariff. The relevant revenue requirement is that for the otherwise applicable rate, adjusted for increased metering costs.

Irrigation: Rate 25

398. The current Rate 25 prices include: 1) a $10.00 Base Rate; 2) a $2.36/horsepower of connected load demand charge; 3) a 2.388c/kwh energy charge; 4) a minimum bill of $18.96/hp of connected load; and 5) a $1.00/kvar charge.

399. MDU. The Company's proposed final prices include: 1) a $10.00 Base Rate; 2) a higher demand charge of $3.35/hp; 3) a higher energy charge of 2.504c/kwh; 4) a higher minimum bill of $24.25/hp and 5) a higher kvar charge of $1.75/kvar.

400. MCC. The MCC's proposed tariff differs substantially from MDU's. The only apparent similarity is a $10.00/month Base Rate. MCC proposed lower demand ($2.27) and energy prices (2.389c/kwh) than MDU. MCC proposed no minimum bill or kvar charge.

401. Commission. The Commission finds relatively more merit in MDU's proposed rate design. The Commission finds merit in the following adjustments to the current tariff to arrive at final prices. First, the energy price must move in the direction of the cost of service results of this order, but with no more than a 10 percent change. All other prices should be equally changed to insure the class revenue requirement is generated.

402. One final comment on this tariff is necessary. As evident from the cost of service section, the roughly 39 customers on this tariff could see a substantially higher future revenue requirement if the Commission's seasonal cost concerns are correct.

Optional Irrigation TOD: Rate 24

403. The current rate design differs from the above irrigation Rate 25 only in the level of the Base Rate ($16.75) and the TOD differentiated energy prices of 3.397c/kwh on-peak and 1.698c/kwh off-peak. The level of the demand charge and minimum bill are equal.

404. MDU. MDU proposed the same existing $16.75 Base Rate, a higher demand charge ($3.35/hp), a higher kvar charge ($1.75) and a higher minimum bill ($24.25). MDU' s proposed on-peak energy charge would increase to 3.696c/kwh, while the off-peak would fall to 1.698c/kwh.

405. Commission. The Commission's decision on rate design for this optional tariff follows. First, energy prices should be set based on the cost of service results of this order to the extent possible. The balance of the class' revenue requirement should be developed by equally adjusting the remaining prices from their current levels. A $1.75 kvar charge is approved.

Feed Grind: Rate 27

406. The current rate design includes a $9.00 Base Rate, a $1.00 kvar charge and a 5.382c/kwh commodity price.

407. MDU. MDU's final proposed tariff would raise all prices. The Base Rate increases to $10.00, the commodity price to 5.498c/kwh and the kvar charge to $1.75.

408. MCC. MCC proposed retaining the $9.00 Base Rate and lowering the commodity price to 5.212c/kwh.

409. Commission. The Commission finds that the commodity price should move in the direction of the cost of service results in this order, but change by no more than 10 percent. Any remaining revenue requirement should be recovered from changes in the Base Rate. Given there are no kvar revenues for this class, a $1.75 charge is approved.

Lighting Service: Rate 41

410. The current rate design features a commodity price only of 6.55c/kwh.

411. MDU. MDU proposed raising the commodity price to 7.629c/kwh for company-owned systems with a $0.00777 credit for municipally-owned systems.

412. MCC. MCC proposed a 6.459c/kwh price for company-owned and a $0.00091 credit for municipally-owned systems.

413. Commission. The Commission approves MDU's proposed differential and resulting prices.

Municipal Pumping: Rate 48

414. The current tariff features a $8.00 Base Rate, $1.37/hp demand charge, a 3.409c/kwh energy price and a $1.00 kvar charge.

415. MDU. The Company's final proposed tariff includes the same $8.00 Base Rate, an increased energy price of 3.896c/kwh and a $1.75 kvar charge. In addition, MDU proposed a complex demand charge that features a $2.50/kw of connected load (a roughly 37 percent increase on a $/hp basis) for loads less than 10 kw. For connected loads in excess of 10 kw, MDU proposed the same $2.50/kw charge bu with a floor charge of $25.00 per month.

416. MCC. MCC agreed to all of MDU's proposals except for the energy price (3.044c/kwh) and the kvar charge.

417. Commission. The Commission finds MDU's proposal interesting. On the one tariff where MDU has affectively proposed to include demand revenues in the minimum bill, the minimum bill makes no mention of the proposal. This peculiarity aside, the Commission approves MDU's proposal with the following adjustments. First, the current energy price must move in the direction of cost of service, but constrained by no more than a 10 percent change. The $1.75 kvar charge is approved which has no apparent revenue impact, although the increase may motivate MDU to now meter and charge the $1.75 price. The remaining revenue requirement must be recovered by equally increasing the other prices to generate the class' revenue requirement; MDU may round the Base Rate, as deemed necessary with the associated revenues recovered from the demand charge.

Private Lighting: Rate 52

418. MDU and MCC. The current and proposed price by both parties for this tariff is 9.685c/kwh.

419. This sole price must be raised to recover the class' revenue requirement.

PART J

OTHER CHANGES

420. From a combination of sources a number of other tariff changes have been proposed. First, from Exh. H (pp. 34-36), MDU proposed several changes including to raise the 10 kw maximum temporary load allowable to 25 kw. The Commission approves the proposed change.

421. Second, the Commission approves of MDU's proposal to make language changes that allow the Company to clearly serve all such master-metered accounts on the appropriate general service rate.

422. Third, MDU has proposed to tariff two different reconnect fees in this docket. Based on MDU's cost estimates the cost of a disconnect/reconnect equals about $18.90. The two separate reconnect charges are 1) $18.00 for seasonal type reconnects, and 2) $12.00 for "nonpayment of bills" type reconnects.

423. The Commission approves of both reconnect charges, and only requires MDU to reflect all associated test year revenues in its cost of service study (billing units times tariffed prices).

424. In addition to the above discussed changes, MDU also included a section in Appendix C of its application titled "Rates Reflecting Proposed Changes". Herein MDU notes proposed changes not discussed in its narrative testimony. Moreover, as evident from a comparison of this section to MDU's current tariffs, MDU has made language changes relative to its current tariff that are not reflected in this section. The following discusses a few Commission concerns from this section of Appendix C.

425. The Commission denies MDU's language additions that refer to supplemental hot water heating installations (e.g., p. 1 of 2 of Rate 10).

426. The Commission denies MDU's language additions that refer to the restriction that electric heating equipment having to be the primary source of space heat.

427. The Commission denies MDU's language additions having to do with subjecting customers with rapidly fluctuating and/or intermittent demand type loads to special rules and regulations.

CONCLUSIONS OF LAW

1. The Applicant, Montana-Dakota Utilities Company, furnishes electric services to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. 569-3-101, MCA.

2. The Commission properly exercises jurisdiction over the Applicant's rates and operations. '69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

3. The Commission has provided adequate public notice of all proceedings and opportunity to be heard to all interested parties in this Docket. Title 2, Chapter 4, MCA.

4. The rate level and rate structure approved herein are just, reasonable, and not unjustly discriminatory. '69-3-330, MCA.

ORDER

1. The Montana-Dakota Utilities Company shall file rate schedules which reflect a $2,290,229 increase in annual revenues less the impacts of the 1986 Tax Reform Act. The net increase will be in lieu of, rather than in addition to, interim rates.

2. The Company is required to submit detailed copies of the workpapers it used to arrive at the impacts of the 1986 Tax Reform Act. These workpapers must also be provided to Mr. Albert Clark, expert witness for the Montana Consumer Counsel.

3. All motions and objections not ruled upon are denied.

4. MDU shall design rates to generate authorized revenues which are consistent with the Findings of Fact entered by the Commission in this Order.

5. Rates shall not be approved until such time as MDU adequately complies with information requested in this Order.

6. In submitting tariffs complying with this Order, MDU shall also submit workpapers detailing billing determinants, final rates, and revenues generated for the existing and resulting rate design of each class.

7. MDU shall provide the Montana Consumer Counsel's witness Mr. James Drzemiecki copies of all resulting tariffs and workpapers also provided to the Commission staff.

8. This Order is effective for services rendered on and after March 19, 1987.

DONE AND DATED this 19th day of March, 1987, by a 3 to 0 vote.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

HOWARD L. ELLIS, Commissioner

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner

ATTEST:

Ann Purcell
Commission Secretary

(SEAL)

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