PSC-1

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of Montana-Dakota Utilities Co.'s

Application to Increase Gas Service Rates

Case No. PU-15-90

DIRECT TESTIMONY

OF

MIKE DILLER

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

August 7, 2015

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Exhibit PSC-1
Public Service Commission Advocacy Staff

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Q: Provide your name and qualifications.

A: My name is Mike Diller. I am the Director of Economic Regulation for the North Dakota Public Service Commission (commission). I am a utility analyst and provide direction to a small staff. I have 30 years of utility regulatory experience that includes providing service to both the Oklahoma Corporation Commission and the commission.

I received a Bachelor of Science Degree in Accounting from Oklahoma Christian College in Edmond, Oklahoma in 1981. I am a Certified Public Accountant and member of the American Institute of Certified Public Accountants. I have testified before the commission on numerous occasions including acquisition and merger proposals, rate cases, settlements, requests for advance determination of prudence and rule changes.

Q: What is the purpose of your testimony?

A: The commission appointed me to advocacy staff (staff) in this proceeding. Staff will provide an analysis and recommendation concerning various cost components of Montana-Dakota Utilities Co.'s (MDU) rate increase request, rate design and the proposed 5-year Rate Stabilization Mechanism (RSM). My testimony will cover three main areas including projected revenues and cost of gas, rate design and the proposed RSM.

Mr. Rothschild will cover cost of capital and Mr. Schock will be addressing rate base and operating expenses.

Q: Please summarize your testimony.

A: MDU's projected 2015 revenues are understated by $987,309. Staff supports using a straight fixed variable rate design for MDU's residential gas customers and the overall principle that customers' rates should be cost based. Staff is opposed to the implementation of the Rate Stabilization Mechanism.

REVENUES AND COST OF GAS

Q: How did you analyze revenues and cost of gas?

A: The 2015 test year includes revenues associated with providing natural gas to MDU's North Dakota customers. The cost of gas is not all that important as long as the projected gas revenues match the projected gas expense; and they do. This is so because MDU files a monthly cost of gas adjustment with the commission to true up actual costs with the base cost of gas included in rates.[1]

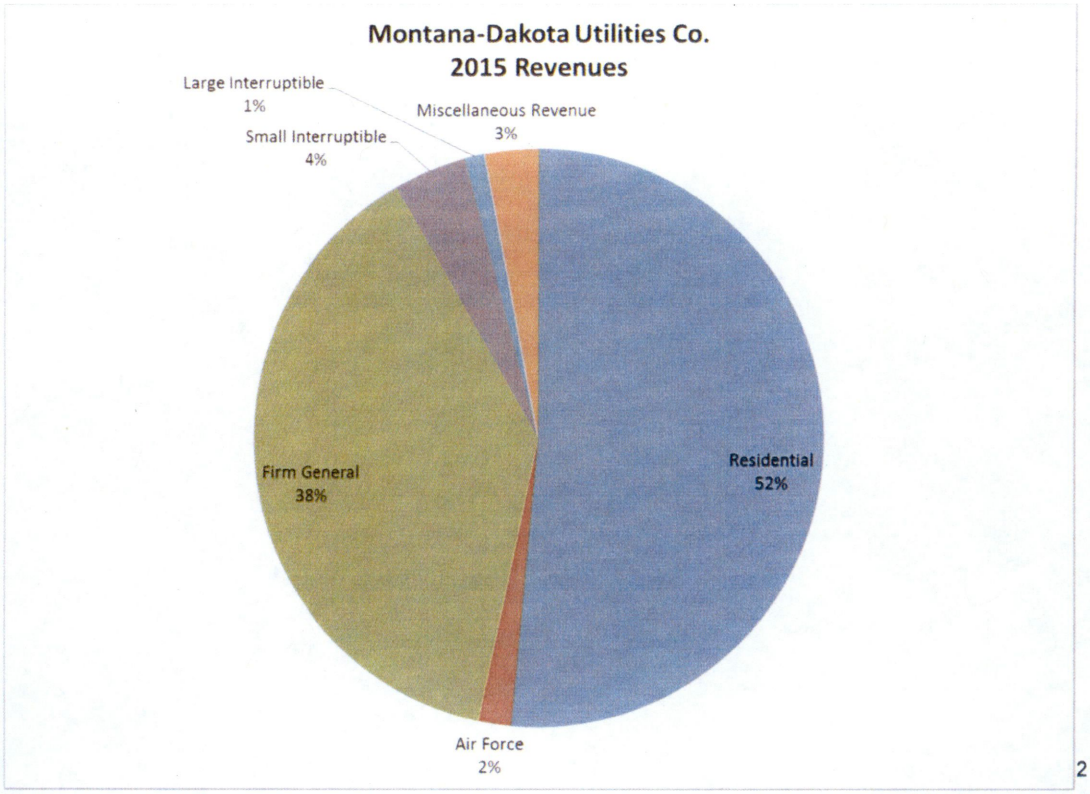
Even though the cost of gas in this proceeding is relatively unimportant, it is not clear to me from MDU's monthly cost of gas adjustments whether it is financially affected when actual line loses vary from the estimated .45%

[1] Cost of gas adjustment tariff, Rate 88.

currently used and proposed in this proceeding. Perhaps the line loss differences between the .45% and actuals washout in the monthly cost of gas filings but I cannot tell when reviewing the monthly cost of gas filings.

Further, it is not clear to me why a line loss factor is included in the monthly cost of gas adjustment since the total cost of gas delivered to the town border station is known whether it is eventually lost or sold. It is late in the proceeding so I write this to provide MDU an opportunity to address the matter in rebuttal testimony or be prepared to address under cross examination at the hearing. Secondly, I write this because the monthly cost of gas filings need to be improved for understandability and this serves as a reminder to both the Company and staff to follow-up on that objective. I have assigned this work to one of our staff members, Ms. Sara Cardwell, who will spearhead a more condensed and more useful monthly report; perhaps a uniform approach for both of North Dakota's investor owned utilities.

My focus here is on the projected revenue streams for the 2015 test year. MDU's billing determinates vary greatly from month to month and year to year so staff used averaging techniques to smooth out the variances in order to provide observable trends. Staff focused its efforts on the larger classes but reviewed all revenues projected by MDU for reasonableness. Following is a chart depicting the makeup of total revenues by class:



[2]

Q: Why are your projections different from MDU's?

A: Staff's projected revenues for the 2015 test year differ from those of MDU. This can be expected given staff had access to more recent data. MDU filed its application and testimony on February 6, 2015; whereas my testimony was filed August 7, 2015. Staff had access to customer and usage levels through May, 2015; whereas MDU only had information through 2014. Even so, staff is only proposing two revenue adjustments since most of the differences are relatively small and generally cancel each other out in terms of total projected revenue.

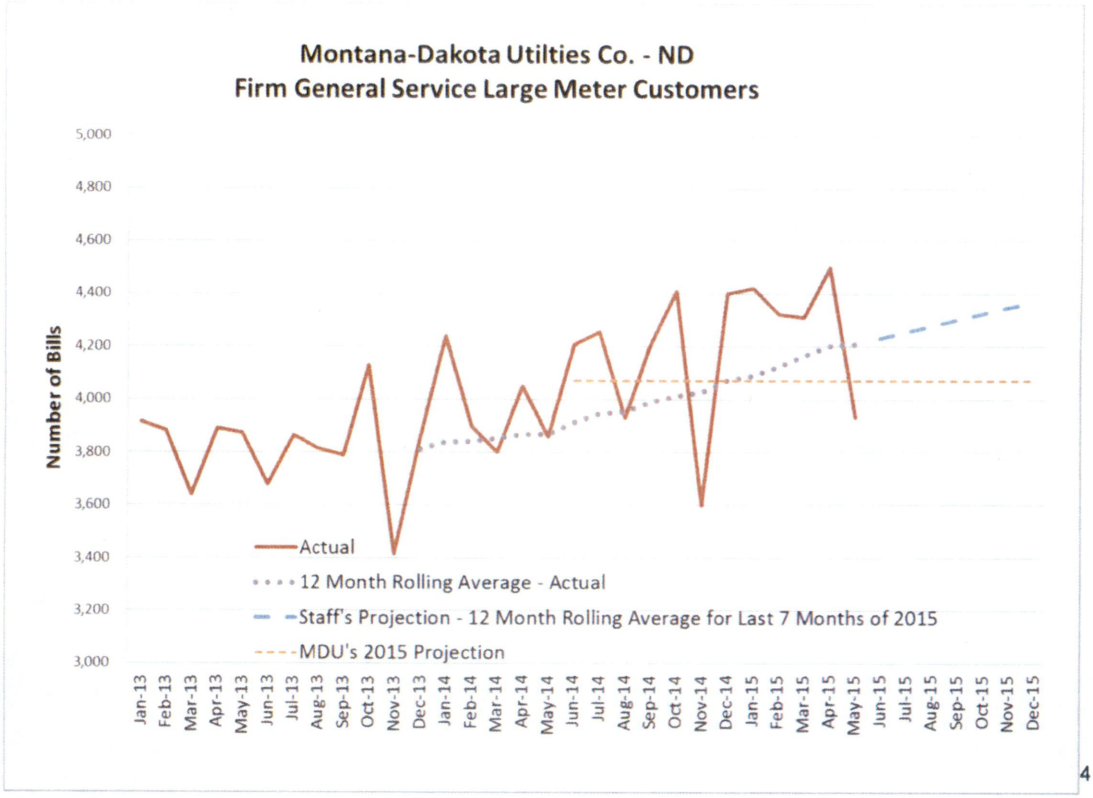
[2] Data extracted from MDU's Statement M, Page 2.

Q: Explain your adjustment to the firm general class.

A: The firm general class is comprised of small meters and large meters and my adjustment pertains to the large meters segment. Aside from the cost of gas, the large meters firm general customer class incurs a daily connection fee of $1.90 (base rate) and a distribution delivery charge of $.73 per dekatherm (Dth) for volumes delivered.[3] Schedule MRD–1 attached to my testimony shows the calculation of staff's adjustment to increase the projected 2015 large meters firm general customer class revenues by $565,124.

The left side of Schedule MRD-1 deals with customer counts and therefore base rate revenue. As you can note, MDU included a customer count level of 4,071 which is equivalent to the average number of customers for the calendar year ending 2014. Since 2014, this class has grown to 4,208 by the end of May, 2015. Staff used an average growth rate since 2013 to arrive at an estimated average customer count of 4,370 for the test year ending 2015. The difference of 299 customers times the daily base rate of $1.90 times 365 days results in increasing MDU's projected 2015 base rate revenues by $207,149. Following is a chart depicting actual data combined with staff's projections for the last 7 months of 2015.

[3] MDU's current Firm General Gas Service Rate 70.

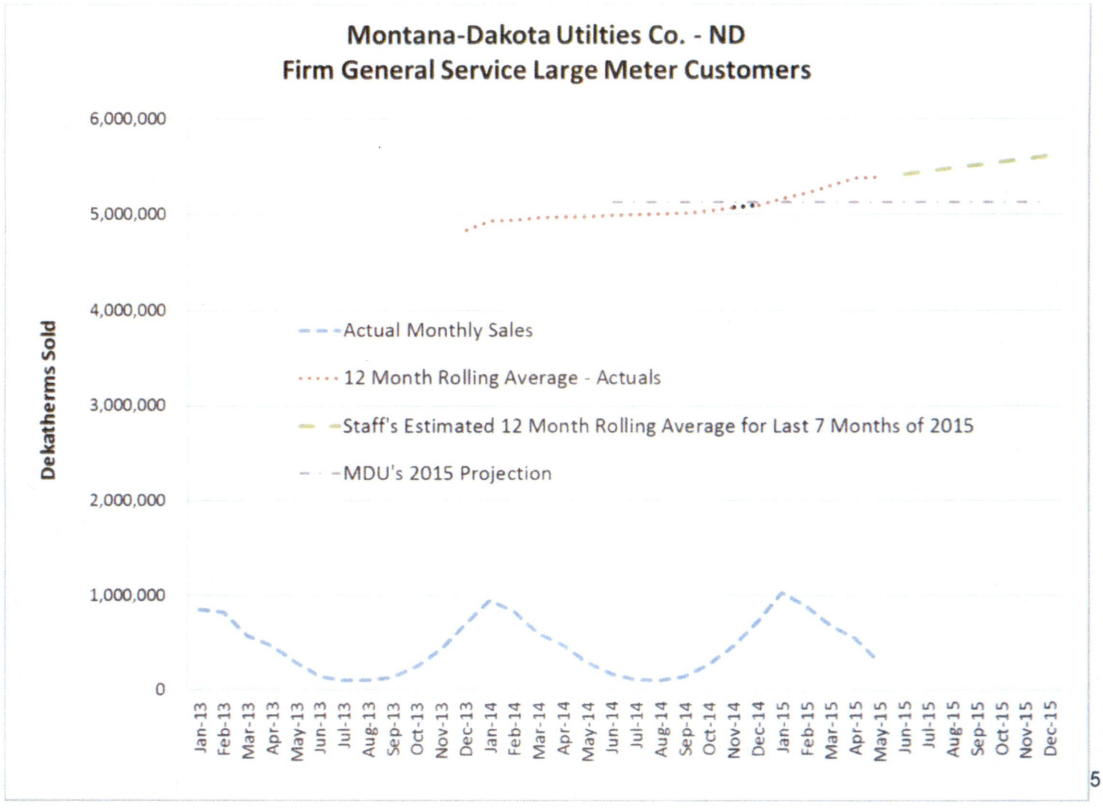


[4]

The right side of Schedule MRD-1 deals with the increased sales largely associated with the increased customer levels. Staff combined the first 5 months of actual 2015 sales with its forecasted sales for the last 7 months using an average growth rate experienced since 2013. The increase in projected sales of 490,376 Dth times the distribution delivery charge (DDC) of $.73 represents an increase in projected DDC revenues of $357,975. When combining the base rate and the DDC revenue increases, the result is an increase to projected 2015 test year revenues of $565,124 or about 13% of the overall requested revenue increase.

[4] Data taken from Data Response 5.1.

Following is a chart depicting actual data combined with staff's projections for the last 7 months of 2015.



[5]

Q: Explain your adjustment to interruptible sales revenues.

A: This adjustment is related to policy rather than a disagreement about forecasted customer or usage levels. In this adjustment, staff proposes to eliminate the margin sharing mechanism related to interruptible sales and instead reflect 100% of sales margins in projected revenues.

[5] Ibid.

Q: Explain the history behind sharing of interruptible sales margins.

A: On May 27, 1994, MDU filed tariff revisions to allow MDU to promote the use of interruptible gas sales. On October 5, 1994, the commission ordered the allocation of the market-based pricing differential from the interruptible sales shall be 50% to MDU and 50% to MDU's firm general use customers. Further the commission ordered that the sharing be implemented through the Purchase Gas Adjustment.[6] The preliminary statement of the Order states that:

1. MDU asked for the shared margins to provide an incentive to MDU to market the interruptible service.

2. The commission reasoned that absent a sharing agreement, MDU shareholders would receive all the benefits of the new tariff because potential customers are not presently full service customers but transportation customers only.

3. The commission concluded that MDU would have to expend considerable effort bringing and keeping potential customers on full service rates and that the incentives are less than allowed NSP under similar circumstances.

[6] NDPSC Order, Case No. PU-399-94-352, October 5, 1994.

Q: Why should the commission change its policy on interruptible sales margins?

A: First and most importantly, there is little reason to provide an incentive to MDU to market its services. It is a monopoly service company with an obligation to serve. As such, the regulatory compact between MDU and the communities it serves is designed so that it has the opportunity to earn a reasonable return on its investment; the very thing this proceeding is about. There is no need to provide extra compensation beyond a reasonable return on MDU's North Dakota investment.

Beyond that, MDU does not have regulatory lag in cost recovery to the same degree that advocacy staff does when utility rates are too high. Staff cannot hire expert witnesses except in the case of rate increases. The burden of proof requires that advocacy staff on its own volition build a prima facie case when MDU over-earns. Of course, doing so would be difficult to accomplish given the size and makeup of staff. Procuring a commission decision to lower rates within 60 days would not be possible. So then, if the commission errs it should err on the side of ratepayers. Further, given the regulatory lag of advocacy staff, there is plenty of incentive for MDU to earn as much as it can between rate cases without an added incentive. It has plenty of natural profit seeking incentive to design competitive rates and sell those services without a revenue kicker.

Today, the interruptible sales customers are paying the maximum tariff rate allowed. If that were to change because the market no longer would support the maximum tariff rate, MDU can file for a rate increase and have interim rates go into effect within 60 days as prescribed by law. This worst case scenario of market competition defeating interruptible rates is diminished when considering that MDU's application in this proceeding significantly increases the small interruptible rate; indicating MDU's belief that a strong market for this service remains.

Secondly, things have changed a lot since implementing the new and improved interruptible gas service tariff in 1994. In 1994, MDU's interruptible sales rates were not competitive and customers were able to use transportation service to secure their own gas supply at a lower cost. Today, the interruptible sales classes are stable and growing. In 1994, the interruptible sales tariff revisions were secured outside the confines of a rate proceeding and so the commission logically concluded that firm customers would be better off getting 50% of the margins of a more competitive tariff than none at all. Today, we are in the midst of a full blown rate proceeding and there is no similar need for sharing margins. We now have many years of experience and operating results under the interruptible sales tariff and can reasonably project revenues for purposes of this rate case.

Apparently in 1994, NSP had a similar provision to share interruptible sales margins. I was unable to locate a case to reference but after looking through NSP's current tariffs and discussing the matter with NSP, it is clear than NSP no longer has such a provision. It is not fair to provide extra income to MDU while not extending the same to NSP; all things being equal.

Therefore, advocacy staff proposes that the commission eliminate the sharing provision associated with the current interruptible sales rates as calculated on the attached Schedule MRD-2. Eliminating the sharing provision will add $422,185 to MDU's projected 2015 revenues or about 10% of the overall requested rate increase in this proceeding.

Q: What do you recommend for grain drying revenues?

A: The grain drying customers are part of the small interruptible class but not included as part of the analysis or adjustment discussed above. In the previous rate case before the commission, the Settlement Agreement adopted by the commission required that 90% of grain drying margins be credited to all other customers through the cost of gas adjustment mechanism. Staff is recommending no change to this practice for the same reason it supported its implementation last time. That is, grain drying activities vary greatly from one year to the next making predicting

future revenue streams to any level of certainty; impossible. The sharing mechanism for grain drying is reasonable in terms and practicality.

In conclusion, staff recommends that the commission increase MDU's projected revenues for its firm general service class by $565,124 and its interruptible sales revenues by $422,185. The two revenue adjustments total $987,309 and reduces MDU's overall requested rate increase by 22%.

RATE DESIGN

Q: What is the purpose of a class cost of service study?

A: The class cost of service study (CCOSS) is the beginning of rate design. It provides an indication of the cost necessary to provide service to each customer class. The cost based information is then considered when designing rates.

Q: How has the commission used the CCOSS in the past?

A: The commission has recognized that the class cost of service study can be done in different ways resulting in different conclusions. The commission considers the CCOSS as a guide rather than a formulaic solution for designing rates. This is observed in a previous commission order, as follows:

"We believe that both fully-distributed embedded class cost of service studies and long run incremental studies may provide useful guidance in designing rates. However, we will continue to use our own judgment considering the evidence, arguments and public policy in a particular case as to an appropriate rate design. We will avoid mechanical application of the results of any given cost study."[7]

Q. Describe the mechanics of a CCOSS.

A. Costs are classified into three categories to assist in the allocation of costs to the various customer classes and bill components, as follows:

1. Customer Related
2. Energy Related
3. Demand Related

Customer related costs are those that vary with the number of customers served. Customer related costs include such costs as customer service connections, meters, service regulators, customer accounting and meter reading. Customer related costs are best reflected in the monthly basic service charge since the cost does not vary with consumption or demand. The assignment of customer costs to the various customer classes is

[7] Order in Case No. PU-400-91-112, Finding of Fact No. 76.

made using customer oriented factors such as number of customers, weighted customers, cost of meters, cost of service regulators etc. The assignment of customer costs can also occur in various combinations with demand and energy costs. Of the 34 allocation factors listed in MDU's CCOSS, all but 6 have a customer component built into the allocator.[8] On a pure number of customers basis (non-weighted), the residential class comprises 86% of MDU's natural gas customers.[9]

Demand related costs vary with the size of plant and equipment necessary to meet the maximum system capacity requirements. Demand related costs include such costs as distribution mains, portions of measuring and regulating station costs and the demand portion of the cost of purchasing gas for distribution. The Peak Design Day allocation factor assigns 47% of demand costs to the residential class.

Energy costs vary directly with the quantity of gas consumed and is primarily made up of the commodity cost of gas.

[8] MDU's Application, Statement O, Page 25ff.
[9] MDU's Application, Statement O, Page 25, Factor No. 4.

Q: What are the rules for applying the cost relationships of customer, demand and energy related costs to the CCOSS?

A: There are no hard and fast rules for applying the various cost types to the CCOSS. There are various methods and multiple ways to allocate costs so that implementation is influenced by the characteristics and judgments of a particular utility. Staff was not inclined to argue for or against every allocator used by MDU in its CCOSS since the commission only uses it as a guide for developing rates. For the sake of determining consistency, staff did compare MDU's current CCOSS with the study filed in its last rate case noting no material differences. If the commission decides to change direction and rely more heavily on the CCOSS for purposes of designing rates, staff recommends that a CCOSS consultant be retained in the next rate case for a more complete review.

Q: Did you identify any areas of concern regarding the CCOSS?

A: MDU continues to use the concept of a minimum distribution system to allocate 25% of distribution mains as customer related. The theory is that some minimum-sized system is required to provide service regardless of whether any gas is used and therefore some portion of the gas mains should be assigned to the various classes based on number of customers. Staff believes that distribution mains are built to deliver the highest expected gas demand for a particular service area. Therefore, mains and other expenses related to distribution mains should be allocated using the

Peak Design Day allocation factor. In most cases, a new service within an area requires only connecting a service line to an existing main, and thus the distribution main costs do not vary with the incidence of customers. Furthermore, when main extensions are needed because of customer growth, MDU has a tariff that requires customers to directly pay main extension expenses that are not cost justified by the amount of projected sales revenues.

Q: What impact does this customer based cost assignment of distribution mains have on the CCOSS?

A: Since customer costs are allocated between the classes based on the number of customers and the residential class has the majority of the customers, the net effect is to shift a larger portion of the revenue requirements to the residential class.

Q: What evidence do you have of the impact to the residential class?

A: I asked MDU to re-run its CCOSS with all distribution main costs assigned on the basis of demand rather than MDU's method of 75% demand and 25% customer based. The rates of return on investment provided by each class of customers are summarized below:

Class	MDU Study	Staff Revised	Difference
Residential	3.4%	4.5%	1.1%
Small Firm	8.5%	8.1%	-0.4%
Large Firm	8.2%	5.9%	-2.3%
AFB - Delivery	55.9%	55.9%	0.0%
Small Interr. Sales	3.8%	1.3%	-2.5%
Large Interr. Sales	12.4%	10.1%	-2.3%
AFB - Distribution	12.9%	13.1%	0.2% [10]

Q: Which version of the CCOSS do you recommend?

A: I do not believe it necessary for the commission to adopt either version. I recommend the commission use the CCOSS as it has used past studies. Class cost of service studies should be used as a guideline, and should not be mechanically applied for designing rates. That said, it is fairly clear that the residential class and small interruptible sales customers are not carrying their full share of costs under either scenario given staff's recommended rate of return of 6.9%.

Q: Have you reviewed MDU's proposed rate design?

A: Yes.

Q: What were your overall objectives when reviewing rate design?

A: To the extent possible, the rate increase and resulting rate design should be allocated to the various customer classes based on cost based principles combined with practicality.

[10] MDU's Application, Statement O and Data Response 6.1.

Q: Can these objectives be met in this proceeding?

A: No. The rates in place today bear the results of many rate cases and commission decisions in the past which may or may not follow current cost structures. If the commission relied upon MDU's CCOSS and only considered its cost based implications, it would increase rates to the residential and small interruptible classes by 7% and reduce rates for the rest of the customer classes.[11] I believe that taking such an approach is not practical.

Q: What rate design does MDU propose?

A: MDU proposes to increase residential rates by 5.8% and small interruptible rates by 6.8% and no increase to the rest of the customer classes.[12] The total proposed revenue increase amounts to an overall increase of 3.4%.[13]

Q: Are MDU's proposed rates practical?

A: While customers never like rate increases, they generally understand that the cost of nearly everything continues to go up; due to inflation if for no other reason. MDU's customers received 4% rate increases in November

[11] MDU's Application, Statement P, last column.
[12] MDU's Application, Page 2 of submittal letter and various places.
[13] Ibid.

2013.[14] As a part of this proceeding, an interim rate increase of 3.4% to all customer classes became effective April 2015.[15] MDU's proposal would add another 2.4% or increases of about 10% to the residential class in less than 2 years. If the commission were to grant MDU 100% of its requested rate increase, I think MDU's proposal moves too quickly to its calculated cost basis when assigning the entire increase to only two customer classes and therefore; not practical.

Q: How has the commission applied rate increases in the past?

A: Generally speaking, the commission has a fairly rich tradition of recognizing both the cost basis and practicality of rate design. When the commission does not order an across-the-board increase to all classes, its general practice has been that no customer class should receive less than one-half or more than twice the overall percentage increase granted. By doing so, the commission avoids rate shock to any one class of customers and moves rates to cost over time. In this instance, MDU requests to increase overall rates by 3.4% so, under this method, no class would receive a rate increase of more than 6.8% or less than 1.7%. In this proceeding, MDU proposes a 6.8% increase to small interruptible customers and a 5.8% increase to residential customers but zero increase for the remaining customer classes.

[14] Commission Order, Case No. PU-13-803, Dated April 9, 2014.
[15] Commission Order, Case No. PU-15-90, Dated March 11, 2015.

Q: How should the overall rate increase be allocated to the various customer classes?

A: I think the commission's general practice is reasonable, but I believe some modifications should be considered. For instance, MDU's CCOSS shows the Air Force providing a return of 55% on its firm and interruptible rates.[16] Due to the very high return, I recommend a rate decrease of $10,000 to the Air Force (Rate 64) representing a .4% decrease in projected revenues. The commission's general rate design practice is insufficient to correct this over time. A $10,000 reduction in rates moves the Air Force's return on investment to serve them to 45%; the amount is immaterial to the overall rate increase; and has an immaterial impact on other customer classes.

Q: Do you recommend other modifications?

A: Yes. When designing rates for interruptible customers, I think the commission should recognize the competitive nature of the interruptible rate classes. Firm customers typically do not have a viable alternative source of heat whereas interruptible customers do. Interruptible customers have the ability to take gas or not take gas depending on the economics of alternative heat sources or the availability of natural gas capacity. Retaining interruptible customers is important in that they

[16] Per Statement O, Page 3 of MDU's Application.

provide profit margins which are beneficial to the rest of the customer classes. Therefore, it is in the best interest of all customers to price interruptible rates just below the market price for alternative heat sources to maximize profits for the good of the whole while retaining interruptible customers and the contribution to earnings they provide.

The current interruptible sales tariffs allow MDU to charge a range of rates so that MDU can flex its rates to meet the prices of alternative sources of energy. Today, MDU charges the maximum rate to all of its small interruptible sales customers suggesting that its maximum small interruptible rates are fully competitive. Further, MDU proposes to increase the small interruptible class (includes sales and transportation) by 6.8% in this proceeding. I agree with MDU's proposal.

Q: Why increase the small interruptible rate class by 6.8%?

A: Because MDU's proposal is market driven, practical and cost based (in order of importance). While MDU has not conducted a market analysis of the competitiveness of alternative fuels, it maintains that it will be able to charge the new maximum rate advocated for in this proceeding. Therefore, staff presumes that MDU understands its business and that the proposed rates are competitive. The proposed rates are practical in that interruptible customers can choose to remain or move to another service or choose an alternative energy source. While the options remain open to

interruptible customers, staff believes that the rates are competitively priced and that customers will remain and provide their fair share of return necessary to serve them.

Please note that while the overall small interruptible class increase is 6.8%, the rate increases for the individual groups within the small interruptible class are 3.5% for small interruptible sales customers; and 29% for small interruptible transportation customers.[17]

Q: Do you support MDU's proposal to eliminate the residential Distribution Delivery Charge (DDC) and the residential Distribution Delivery Stabilization Mechanism (DDSM) and thereby recover all non-gas residential revenues through the base rate charge?

A: Yes. Staff strongly supports this change to a straight fixed variable rate (SFV) for residential customers for a host of reasons:

1. Eliminates confusion over what DDC and DDSM represent because it is not apparent to the average consumer. On the other hand, one fixed customer charge and one variable charge for usage is very easy to understand. You pay one fixed rate to have access to the North

[17] Calculated using MDU's Exhibit TAA-1 and Statement P, Page 6. Also, see attached Schedule MRD-3.

American gas fields and you pay one variable rate for the gas that you use.

2. The current DDC is set at 32.6 cents per Dekatherm (Dth) or $32.60 a year for a typical customer using 100 Dth a year. There is simply no reason to confuse people with a charge averaging less than $3 a month; even if the charge was cost based.

3. There is no cost basis for the DDC. According to MDU's CCOSS there is only 3 cents a Dth of energy related costs beyond the commodity cost of gas. Again, there is no reason to add a separate line item to customers' bills for 3 cents per Dth of use. When the commission ordered NSP to move to a SFV rate, much time was spent at the hearing discussing fixed and variable costs associated with natural gas service. In that proceeding, NSP was unable to identify any significant variable costs beyond the commodity cost of gas. There was no cost basis in that proceeding or in this proceeding to justify the continued use of a variable rate (DDC) for residential customers beyond the commodity cost of gas.

4. Projecting revenues for ratemaking purposes is much simpler and more accurate under a SFV rate. The continued use of the DDC requires forecasting customer numbers as well as weather normalized

usage. Under the SFV rate, it is only necessary to forecast customer numbers; actual customer levels are easily observable. Maintaining the DDC requires that actual usage be converted to weather normalized usage using heating degree day information for trend analysis and revenue forecasting.

5. Eliminating the DDC results in the elimination of the DDSM which accounts for differences in sales due to colder or warmer than normal weather. Under the SFV rate, residential margins earned will not vary with fluctuations in weather. The DDSM adds complexity to the bill and is not easily determinable or verifiable by customers. The unnecessary complexity leads to confusion and distrust of customers.

6. The commission has a decade of positive experience with the SFV rate for NSP's natural gas customers. When the commission implemented a $15.69 monthly customer charge replacing the existing charge of $5.50, it eliminated NSP's DDC.[18] Of the few customer complaints received, most quickly relinquished their concern when discovering that the DDC had been eliminated. Today, NSP charges its residential customers $18.48 per month compared to the recommended rate of $18.46 per month for MDU in this proceeding.[19]

[18]Case No. PU-04-578.
[19] Schedule MRD-3, Line 32.

7. Customers today are quite familiar with fixed charges whether the service is used or not, such as: cable television; cell phones; wire line phones; internet service, health club memberships etc. They understand that there are a lot of fixed costs associated with providing service whether they use the service or not. Access to natural gas for less than $20 a month for a territory north of the 46th parallel seems very understandable and reasonable in today's culture of fixed charges.

8. The SFV rate decouples earnings from sales volumes, thus eliminating any disincentive on the company's part for promoting conservation among residential customers. Similarly, since more than two-thirds of the residential class revenues will remain variable based on the usage of natural gas, customers will remain encouraged to conserve.

9. Seasonal differences in utility revenues and customer bills are smoothed out because winter gas bills are less and summer bills are more under the SFV rate proposal.

Q: Why not apply SFV to other customer classes?

A: The SFV rate works well for the residential class because gas companies have almost no energy (or volumetric) related costs

beyond the commodity cost of gas. The system is built and in place ready to serve regardless of volumetric differences from one month or one day to the next. It works well for the residential class because demand requirements from one house to the next are not demonstrably different and therefore can be represented as a fixed cost rather than an energy charge.

This is also true for the small general service class that uses only twice that of the average residential class. Staff is not arguing to extend this to the small general service class but is certainly willing to consider it in this proceeding or in a future filing for the same reasons that the SFV rate is good for residential customers.

Q: Do you have any other rate design recommendations?

A: Yes. I don't believe that MDU's proposed increase from $15 to $40 for a returned check charge is fair or reasonable.[20] My bank charges $30 for a non-sufficient fund check in Bismarck; and less in the smaller communities it serves. Other banks charge more. When combining MDU's proposed charge and a bank charge for an NFS check, the fees are more than the cost of one month's gas service for an average residential customer. I don't believe this level of charge to customers who can least afford it is fair or reasonable and it does little

[20] MDU's proposed tariffs for Rate 100, General Provisions, Page 13.

to help them recover or catch up on paying their gas bills. I recommend no change in the return check charge of $15.

Q: Summarize the rate changes proposed by staff.

A: The attached Schedule MRD-3 summarizes staff's recommended adjustments to rates to coincide with its recommended revenue increase of $1.367 million. As you can see from Schedule MRD-3, staff recommends a slight decrease to the Air Force Rate 64; a 3.5% increase to the Small Interruptible Sales Rate 71; a 29% increase to the Small Interruptible Transportation Rate 81 and a 1.5% increase to the residential class. A 1.5% increase to the residential class will amount to an average monthly bill impact of 91 cents per month.

So it is clear to the American Association of Retired Persons (AARP), staff's proposal will increase the monthly base rate by $3.46 or 23%. **However, staff's proposal will eliminate 100% of the current distribution delivery charge.**

Q: What if the commission grants a much larger increase than staff is recommending?

A: I don't believe the commission should increase the residential class beyond the interim rates already in place. The higher the increase

granted, the more I would recommend that the commission use its more standard approach discussed earlier.

RATE STABILIZATION METHOD

Q: What is the purpose of the RSM?

A: MDU's President and CEO, Ms. Kivisto, in direct testimony states that it will address the economic uncertainty in its service territory by providing a means to address changes in investments and volatile return levels.[21] Ms. Kivisto further argues that the RSM will help reduce the need for future regulatory filings, encourage good performance and reward the Company and customers for the results.[22] MDU's Director of Regulatory Affairs, Ms. Aberle, in direct testimony states that the RSM provides a better means of recognizing changes in system growth, customer usage and the potential for increased conservation than does traditional ratemaking principles and that customers benefit by sharing in efficiency savings on a timely basis while eliminating the need for rate cases and associated regulatory costs.[23]

Q: Can you summarize the RSM?

[21] Ms. Kivisto's Direct Testimony, page 11.
[22] Ms. Kivisto's Direct Testimony, top of page 12.
[23] Ms. Aberle's Direct Testimony, page 10.

A: The proposed RSM will be effective for 5 years beginning in 2016 and provide for an annual review of actual earnings. To the extent earnings are less than 9.5%, MDU will be allowed to collect additional revenues to secure a 10% earnings level. In addition, MDU will provide an estimate of earnings for the next year and raise rates, if necessary, to increase projected earnings to 10% while limiting O&M expense increases to 5% a year. In the event earnings are above 10.5%, MDU will return one-half the earnings above 10.5%. The increases will be allocated on an equal percentage basis to the non-gas rate components applicable under each rate schedule.

Q: Do you have any experience with a proposal like the RSM?

A: The commission approved a 4-year rate plan for NSP's electric operation for 2013-2016 as part of a very extensive and wide ranging settlement between staff and NSP. The 4.9% increases for each of the first 3 years were based on our best estimates of earnings for 2013, 2014 and 2015 combined with a moratorium on rates during 2016 as part of broader settlement considerations. It is difficult to predict earnings one year out, let alone two or three years out, but because of extensive budget work and other concessions garnered through negotiations, a long-term agreement was reached. The agreed to return on equity for purposes of settlement included 9.75% to 10.25%. Any earnings above the applicable return on equity for a

given year are shared equally with customers whereas any deficiencies in earnings are not charged to customers.

The commission also embarked on a 5-year Performance-Based Regulation (PBR) plan for the electric operations of NSP and Otter Tail Power Company between the years of 2001-2005. PBR was a robust plan including price caps, earnings sharing, and performance adjustments for reliability, satisfaction, safety and price competitiveness. The plan was not extended beyond the original agreement because of the difficulty in predicting long-term capital needs in an infrastructure buildout period.

Q: Why is staff opposed to the RSM?

A: MDU is a natural monopoly and as such the commission's decisions and orders are a surrogate for competition. The free enterprise system we enjoy in the United States works to squeeze out excess profits so that its people enjoy competitively priced goods and services. Since MDU's gas operations do not face these kinds of economic pressures, any long-term regulatory agreement that displaces rate cases before the commission must act as a surrogate for competition. I don't believe the RSM effectively meets that objective.

Q: Why doesn't the RSM provide an effective regulatory model?

A: Regulatory lag and effective regulation are state commissions' greatest tools for providing surrogate competition. However, regulatory lag has been all but eliminated in North Dakota through legislative action allowing for the use of forecasted test years and interim rates that are effective within 60 days of a rate increase application. Regulatory lag is why some states use historical test years and only adjust for known and measurable changes. Regulatory lag is a strong cost containment mechanism. Despite our laws, I believe utility companies are reticent to file annual rate increase applications due to community and regulatory pressure they may fear or encounter. So then, any lag in recovering costs are self-imposed by utility companies. There really isn't any regulatory lag in North Dakota; only filing lag.

This proposal eliminates even the filing lag through annual rate adjustments that are applied both backward and forward. The proposed Rate 89 tariff (RSM) codifies and requires annual filings and adjustments. If last year's earnings are insufficient, next year's earnings are trued up through more charges to next year's bills. In addition, if next year's projections indicate earnings will be insufficient, more charges are added to next year's bills.

Generally, long-term rate settlements or performance plans negotiated by staff attempt to create a competitive environment through regulatory lag, price caps, rate moratoriums, performance obligations and other tradeoffs. Staff sees very little of this in the proposed RSM other than limiting operation and maintenance cost increases to 5% a year. Even that performance measure is limited in that the RSM tariff provides MDU may request a change in the base operation and maintenance expense level.

Since the turn of the century, MDU has filed four gas rate increase applications. MDU filed three rate cases in the 1990's and 2 in the 1980's. Making annual filings for the next five years demonstrating the Company's financial performance accompanied by detailed computations clearly showing the derivation of relevant amounts; statements of reason for any observed changes in financial operation; all relevant supporting work papers; revised tariff sheets; true-up calculations; forecasted financial expectations and so on appears to add to the regulatory burden; not lessen it. Staff is concerned that the annual filings and true-up adjustments will result in annual rate increases.

I recommend that the commission not remove the community and regulatory pressure MDU faces when deciding to file for another rate

increase and it should not make the process to raise rates any easier than it is already. The commission should be careful in guaranteeing long-term rates of return through annual filings as it will diminish the need for MDU to act like a competitor in the market place.

Q: Does this conclude your testimony?

A: Yes, it does.