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 CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service in the State of Montana	)))))	REGULATORY DIVISION DOCKET NO. D2015.6.51

DIRECT TESTIMONY AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

MONTANA LARGE CUSTOMER GROUP

November 20, 2015

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. PLEASE DESCRIBE YOUR EDUCATION.

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. ("Ebasco"), as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost of service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity, I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing, as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of Electrical World. My article on "Standby Electric Rates" was published in the November 8, 1984, issue of Public Utilities Fortnightly. In February 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit SJB-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Montana Large Customer Group ("LCG"), which is comprised of customers taking service under Rates 30 and 35 from Montana-Dakota Utilities Co. ("MDU" or the "Company").

I. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I generally respond to the direct testimony of MDU witnesses Sara Cardwell and Tamie Aberle on class cost of service, the apportionment of the rate increase to rate classes ("rate spread"), and rate design.

With regard to class cost of service issues, I will discuss the Company's filed Average and Excess Demand ("AED") study and explain why it is not appropriate for MDU is this case. I have identified a number of problems with the AED study that I will address in my testimony. In addition, I will discuss the fact that the Company's AED study unreasonably allocates production and transmission costs to Rate Schedule 35. Rate 35 consists of a single customer (Denbury Onshore LLC) whose non-coincident peak demand occurs in an off-peak period. Since production and transmission demand-related costs are caused by the need to maintain adequate facilities to serve during peak periods, the Company's proposed methodology over-allocates production and transmission demand-related costs to Rate 35 and under-allocates those costs to the customers who are driving the peaks.

I will present an alternative 12 coincident peak ("12 CP") cost of service study that more reasonably assigns costs to each of MDU's rate schedules. MDU itself uses a 12 CP methodology to allocate production and transmission demand related costs in its jurisdictional allocation of total MDU costs to Montana.

In addition, I will also present corrected AED and 12 CP class cost of service studies that (1) reflect an alternative classification of wind generation costs between energy and demand from the 83.5% energy, 16.5% demand proposed by MDU, and (2) correct the Company's allocation of an adjustment that it made to test year production O&M expenses. The AED correction also includes a change in the peak demand used by the Company to determine the portion of costs allocated by average demand and the portion allocated by excess demand.

Based on the results of these alternative class cost of service studies, I will recommend an alternative allocation of the overall revenue increase to each of MDU's rate classes that reasonably reflects cost responsibility.

I also address rate design/cost allocation issues associated with the Company's proposed Transmission Cost Recovery Rider ("TCCR") and the Environmental Cost Recovery Rider ("ECCR"). As discussed by Mr. Higgins, the LCG recommends that these riders be rejected. However, in the event the Commission adopts the proposals, the Company's proposed rate recovery for the charges on a kWh basis does not reasonably reflect the underlying costs being recovered. I will recommend alternative rate design/cost allocation treatments for these charges. Finally, I discuss the Company's proposed rate recovery of deferred costs associated with changes in the Public Service Commission ("PSC") and Montana Consumer Counsel ("MCC") taxes.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE?

A. Yes. I make the following recommendations:

- MDU's AED class cost of service study should not be used to apportion the overall revenue increase to rate classes in this case due to problems that, among other things, unreasonably allocate costs to Rate 35. The Commission should adopt a 12 CP cost of service study in this case, consistent with the methodology MDU used to allocate total MDU production plant and demand related expenses to the Montana jurisdiction.

- The Company's proposed uniform percentage rate increase to each rate class should not be accepted in this case because it is inconsistent with cost of service and results in some rate classes unreasonably subsidizing other rate classes. The Commission should apportion the approved revenue increase to rate classes using the cost of service results from a 12 CP cost of service study, with mitigation such that no rate class receives an increase larger than 1.5 times the average system percentage increase.

- If the Commission approves the Company's proposed TCRR, the rider should separately assign transmission costs to rate classes on the basis of the transmission demand allocation factor approved in this case (*e.g.*, the 12 CP factor that I am recommending or the AED factor if that methodology is approved by the Commission). For demand metered rate classes, such as Rates 30 and 35, the allocated TCCR costs should be recovered on a $/kW basis, not on a ¢/kWh as proposed by the Company. Similarly, if the ECRR environmental cost recovery rider is approved, ECRR costs allocated to demand metered rate classes should be recovered on a $/kW basis.

- The Company's proposed recovery of PSC and MCC taxes should be on the basis of a percentage factor applied to customer bills, not on a ¢/kWh basis as proposed by the Company. A percentage recovery factor is consistent with the incurrence of these costs by the Company.

II. CLASS COST OF SERVICE ISSUES AND REVENUE APPORTIONMENT

Q. HAVE YOU REVIEWED THE COMPANY'S FILED EMBEDDED COST OF SERVICE STUDY?

A. Yes. The Company filed an embedded cost of service study based on a 12 month test year ending December 31, 2014. As discussed by MDU witness Sara Cardwell in her direct testimony, the Company used an Average and Excess Demand ("AED") methodology to allocate production demand and transmission demand costs to rate classes. The AED allocator assigns a portion of these fixed demand related costs on the basis of average demand, which is identical to rate class kWh energy, and excess demand that is defined as the difference between a class's maximum demand (*i.e.*, class non-coincident peak demand or "NCP") and its average demand.

Under a traditional AED method, the percentage of costs allocated on the basis of average demand is determined by the system load factor; and the remaining costs (1 minus the system load factor) are allocated based on each class's share of excess demand. In the Company's AED study, this is accomplished by subtracting the 2014 average demand mW from a three-year average July peak demand to produce an "excess" system demand. The system average demand mW are allocated to each rate class on the basis of that class's average demand and the excess system demand is allocated to rate classes on the basis of each class's NCP demand. The AED factor for each class is the sum of its allocated average demand and excess demand, as a percentage of the summation of these amounts for all rate classes.[1]

For distribution costs, the Company classified each component of the system as either demand or customer related, based on an analysis of cost causation.

Q. ARE ALL FIXED PRODUCTION COSTS ALLOCATED USING THE AED ALLOCATOR?

A. No. For wind facilities, the Company only allocated 16.5% of fixed costs on the basis of the AED factor. The remaining 83.5% of wind fixed costs are allocated on rate class kWh energy.

A. **<u>Concerns with MDU's class cost of service study.</u>**

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S FILED CLASS COST OF SERVICE STUDY?

A. Yes. I have concerns in two areas. First, the AED allocator used to assign production and transmission demand costs to rate classes produces unreasonable results in this case by over-allocating costs to Rate 35 and under-allocating costs to those customers who are more responsible for the system peaks and, therefore, more responsible for the need to incur fixed costs for generation and transmission capacity. Second, the Company's classification of wind facilities as 83.5% energy related is not reasonable. While I

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[1] This is identical to allocating by apportioning costs into two categories. The first category is determined by multiplying the system load factor percent times the cost and the second category would be the remaining costs [(1 minus the load factor) times the total cost]. The first category is allocated to rate classes on average demand; the second category of costs is allocated on each class's share of excess NCP demand.

generally believe that wind facility costs should be allocated in their entirety using a demand allocation factor, if the fixed wind facility costs are deemed to be both energy and demand related the classification of 83.5% of these costs as energy related is excessive. I will recommend an alternative classification.

Q. HAVE YOU IDENTIFIED ANY OTHER ISSUES WITH MDU'S CLASS COST OF SERVICE STUDY?

A. Yes, I identified two other issues with MDU's cost of service study. First, I identified an error in the Company's allocation of its adjustment to production O&M expenses that I will explain and correct. Second, the Company's use of a three-year average July peak in its AED factor development is unreasonable, since it compares a three-year peak demand to a test year 2014 average demand to determine the excess system demand.

Q. WOULD YOU DISCUSS YOUR CONCERNS WITH THE COMPANY'S PROPOSED AED ALLOCATION METHODOLOGY?

A. While the AED methodology can be a reasonable approach and I have supported its application in other cases, I have concerns about the Company's filed study in this case. As I indicated earlier, a review of the AED allocation factor development[2] of the class cost of service study[3] shows that the Company calculated the "excess demand" portion of the AED allocator by comparing a three-year average July Montana peak mW to the average demand mW in 2014. The standard methodology for determining the excess demand component of an AED factor is to subtract the average demand in the test year from the peak demand in the test year. This excess demand is then allocated to rate classes on the basis of class NCP. In the Company's AED study, MDU subtracted the

[2] Tab "demand & energy-AED"
[3] Statement L excel spreadsheet.

test year average demand from a three-year historical July peak demand to determine the amount of "excess demand" that is allocated to rate classes. Exhibit SJB-2 contains the Company's AED factor development. The box at the bottom of the exhibit shows the Company's calculation and includes a footnote (1) that states: "Peak based on the state of Montana using a three year average for July." The Company has subtracted the test year average demand of 99,125 from this three-year average peak (130,289) to obtain the excess demand that is then allocated to rate classes on the basis of class NCP. The excess demand is shown to be 31,164. This amount is then allocated to rate classes and added to each class's average demand to determine the Average & Excess Demand shown in the last column of the exhibit.

Q. WHAT IS THE PROBLEM WITH THE COMPANY'S METHODOLOGY?

A. MDU has compared a three-year peak demand to a one-year (2014) average demand to develop the AED allocator used in its cost study. There is no justification for such a mismatched calculation. The resulting "excess demand" does not represent a correct amount of excess demand because the "peak" is a three-year average.

Q. ARE THERE ADDITIONAL PROBLEMS WITH THE COMPANY'S AED ALLOCATOR?

A. Yes. The AED factor does not reasonably assign costs to Rate 35, which is a contract service rate class consisting of a single customer, Denbury Onshore LLC. In some cases, the AED methodology assigns costs to a rate schedule comprised of a single customer based on that customer's *off-peak* demand. This occurred for Rate 35 in the Company's AED cost study in this case.

Q. CAN YOU EXPLAIN WHY THIS OCCURRED IN THE COMPANY'S STUDY?

A. Yes. As I discussed earlier, the AED allocator uses a rate class's maximum demand to determine the "excess" portion of the allocation factor. In the case of Rate 35, this maximum demand occurs in April, which is an off-peak month. Table 1 below shows the monthly MDU Montana peak demands for the test year (2014) and the five preceding years (2009 through 2013). Also shown for each year are the monthly rankings (highest peak equals "1").

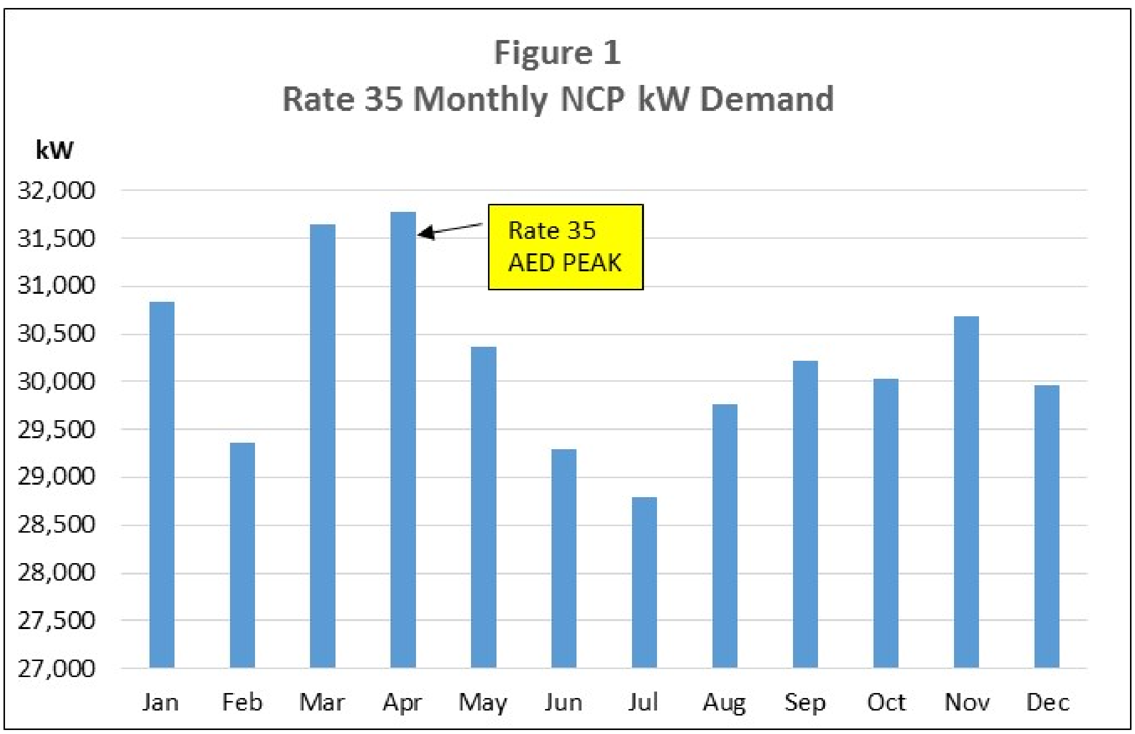
Table 1
Comparison of Monthly Montana MDU Peaks
(2009 - 2014)

	2009		2010		2011		2012		2013		2014	
Month	MT kW	Monthly Rank	MT kW	Monthly Rank	MT kW	Monthly Rank	MT kW	Monthly Rank	MT kW	Monthly Rank	MT kW	Monthly Rank
Jan	99.6	7	111.3	3	101.9	7	114.5	5	106.8	6	114.5	7
Feb	97.6	8	98.6	7	106.1	4	101.6	8	96.7	10	109.4	8
Mar	101.8	6	95.4	8	101.6	8	77.1	12	90.3	12	121.5	5
Apr	84.2	11	82.1	11	71.1	12	84.0	11	95.1	11	98.8	10
May	79.9	12	76.8	12	74.4	11	88.7	9	102.0	7	90.9	11
Jun	108.3	4	106.9	5	112.8	2	117.1	4	101.6	8	102.0	9
Jul	114.2	2	115.8	2	117.8	1	141.8	1	129.0	2	140.4	1
Aug	109.0	3	116.2	1	109.6	3	127.1	2	122.9	3	131.9	2
Sep	103.3	5	93.1	9	105.4	5	108.8	6	133.0	1	121.2	6
Oct	87.7	10	91.6	10	75.2	10	86.4	10	98.8	9	85.9	12
Nov	91.0	9	104.4	6	91.9	9	107.5	7	115.5	5	130.1	3
Dec	117.4	1	109.3	4	104.4	6	120.8	3	118.5	4	128.1	4
	1,194.0		1,201.5		1,172.2		1,275.4		1,310.2		1,374.7	

In each of these six years, the highest Montana monthly peaks occurred in a summer month, though peaks in some winter months were also high. None of the peaks occurred in April. In fact, the Montana April peak was consistently ranked the 10th, 11th, or 12th lowest. That means that when the Company decides whether there is a need to incur the fixed costs to increase generation or transmission capacity to meet peak loads, the loads in April are not a significant factor.

Q. HOW DO THE RATE 35 MONTHLY NCP DEMANDS COMPARE TO THE MONTANA SYSTEM?

A. Figure 1 below shows the monthly Rate 35 maximum demands used by the Company to develop the AED factor. As can be seen, the maximum Rate 35 peak occurred in April. The NCP demand for Rate 35 is shown to be 31,683 kW.[4] This was the basis for the Rate 35 excess demand calculation. Based on this result, the AED allocator is not a reasonable basis to assign costs in this case. For Rate 35, 24% of production and transmission demand costs are being allocated on the basis of the April peak demand.[5] Again, since the fixed costs of generation and transmission facilities are incurred to meet peak loads, this methodology is not consistent with cost causation and demonstrates the failure of the AED method to reasonably allocate costs to the customers driving the system peaks and causing the costs to be incurred.



[4] *See* Exhibit SJB-2
[5] The excess demand portion of the AED factor allocates 24% of costs.

Q. HAVE YOU IDENTIFIED ANY OTHER PROBLEMS WITH THE DEVELOPMENT OF THE RATE 35 AED ALLOCATION FACTOR?

A. Yes. The Company's calculation of the Rate 35 class NCP demand, which is used in the AED factor to develop "excess demand," is actually the sum of a single customer's billing point maximum demands and not the Rate 35 NCP. In the AED methodology, the NCP demand is the class maximum diversified demand, not the sum of the maximum demands of the customers (or billing meters) in the class without any adjustment for diversity.

For example, assume a rate class is comprised of two customers. If customer A has a maximum billing demand for the month of 100 kW and customer B has a maximum billing demand in that month of 200 kW, the combined loads of these two customers will not likely be 300 kW in any given hour (which would require both customers to achieve their maximum demands during the month in the identical hour). Because of diversity between the customers' loads, the likely maximum demand of the class as a whole (NCP) will be lower than the sum of each customer's maximum demands that are used for billing purposes.

Without accounting for diversity, the Rate 35 NCP demand is overstated and therefore the Rate 35 AED factor is overstated. Based on a review of the billing demands for Rate 35 provided in response to MCC-125 and the NCP demands for Rate 35 provided in response to LCG-009, the Company used the Rate 35 billing demands to determine the Rate 35 NCP demand for calculating the AED factor. Exhibit SJB-3 shows a comparison of these two sets of monthly demands for Rate 35. While there is some slight difference (0.3%) between the two sets of data in the first four months of the year, the billing demands and the NCP demands are identical for the remaining eight months. The correct AED factor NCP should be based on the demands of these 11 billing points in the single hour in which Rate 35 achieves its maximum demand (*i.e.*, Rate 35's NCP). This is the correct method for determining the class NCP in an AED methodology. Effectively, MDU's approach ignores the impact of any diversity among the 11 delivery points whose loads comprise Rate 35, overstates the NCP demands, and biases the AED cost of service study by overstating the cost responsibility of Rate 35.

B. <u>Alternative 12 coincident peak allocator.</u>

Q. GIVEN THE PROBLEMS WITH THE COMPANY'S AED STUDY, HAVE YOU DEVELOPED AN ALTERNATIVE PRODUCTION AND TRANSMISSION DEMAND ALLOCATOR THAT WOULD BE MORE APPROPRIATE IN THIS CASE?

A. Yes. I developed a traditional 12 CP allocator using rate class contributions to each of the 12 monthly peaks. The Company itself uses a 12 CP methodology to develop its Montana jurisdictional cost allocation of total MDU costs. In other words, the underlying cost basis for Montana jurisdictional production and transmission costs is MDU Montana's contribution to the MDU 12 CPs.

Q. WOULD YOU PROVIDE A BRIEF EXPLANATION OF THE 12 CP METHODOLOGY?

A. The 12 CP method allocates production and transmission demand costs on the basis of each rate class's load at the time of each of the 12 monthly MDU Montana peaks. It is a peak demand responsibility methodology that allocates costs based on all 12 monthly peaks. It recognizes that MDU plans its system to meet the peak demands of its customers.

Q. HOW DID YOU DETERMINE THAT THE COMPANY USES A 12 CP DEMAND ALLOCATION METHOD TO ASSIGN TOTAL MDU PRODUCTION AND TRANSMISSION DEMAND COSTS TO THE MONTANA JURISDICTION?

A. Exhibit SJB-4 contains three excerpts from the Company's Application in this case (Statement G, pages 9, 10 and 14).[6] These pages summarize Pro Forma adjustments to various production demand related costs that the Company included in its test year. In each case, the footnote states that the total utility cost was allocated to Montana on the basis of "Factor 15: Integrated System Peak Demand." Page 4 of Exhibit SJB-4 contains an excerpt of the "Factors" Tab of the Statements A-K excel workbook. Factor 15 is specified as: "Integrated System 12 month Peak Demand." These schedules demonstrate that the Company uses each jurisdiction's contribution to the 12 monthly peaks to allocate production related costs. Integrated system transmission costs are also allocated to jurisdictions using this methodology.

Q. ARE THERE ADDITIONAL REASONS THAT THE COMMISSION SHOULD ADOPT THE 12 CP METHODOLOGY IN THIS CASE?

A. Yes. As I explained, the Company uses the 12 CP methodology as the basis for the allocation of production demand and integrated transmission demand costs to all of Montana. Effectively, the 12 CP methodology "creates" the production and transmission demand costs that are at issue in this case and the costs that are being allocated to rate classes in the class cost of service study. This means that if customer loads in Montana increase or decrease in any of the 12 months during the year, Montana's costs increase or decrease (assuming no corresponding increase in loads during that month in MDU's other jurisdictions such as North Dakota).

[6] Exhibit SJB-4 at pages 1-3.

The Company's AED method ignores this important price signal information by focusing on class NCP demand. The purpose of a class cost of service study is to assign costs to rate classes on the basis of factors that "cause" costs. In Montana, these factors include customer loads at the time of each of the monthly peaks (Integrated System 12 month peak demands); they do not include class NCP demands that form the basis for the AED method used by the Company. This supports a rate class cost allocation methodology that also uses the same 12 CP approach so that customers receive correct price signals (*i.e.*, an increase in customer loads during any month cause costs to increase in Montana). The AED method ignores this price signal information; the 12 CP method captures this price signal information.

Finally, because the 12 CP methodology is used for interstate cost allocation purposes, using that methodology for in-state cost allocation may lead to more stable rates. For example, if a Montana customer decreases their usage on peak in response to higher rates, that will decrease the costs assigned to Montana. Thus, a correct price signal results in stability in terms of the relationship between costs and revenues. However, if a Montana customer like Denbury responds to a rate increase by decreasing off-peak usage (since it is the customer's off-peak usage that is driving the cost allocation result), that lowers the Company's revenues but <u>does not</u> change the costs assigned to Montana. Thus, an incorrect price signal can create a gap between revenues and costs and that gap can trigger the need for a rate filing to make up the difference.

Q. THE COMPANY PROVIDED RATE CLASS 12 CP DEMANDS IN ITS RESPONSE TO LCG-010. DID YOU RELY ON THE COMPANY'S CALCULATIONS OF THE 12 CP ALLOCATION FACTORS FOR YOUR 12 CP COST OF SERVICE STUDY?

A. Only in part. My review of the Company's calculations indicated that there was a problem with the Company's loss factors in its 12 CP demand development. The 12 CP allocator is based on each rate class's demand at the time of the monthly MDU system peak, with losses included from the meter to the supply voltage level. In Statement L, which is the Company's AED cost of service study, MDU calculated losses for Rates 20, 31, and 35 recognizing that these classes serve customers at primary and secondary voltages (Rates 20 and 31) and at a higher voltage for Rate 35. In the Company's calculation of 12 CP demands provided in response to LCG-010, the Company applied secondary losses to the entire amount of load on Rate 20 and used primary losses for the entire amount of demand for Rate 31. For Rate 35, the Company incorrectly calculated losses using primary voltage loss factors, rather than the correct lower loss factors. Table 2 shows this comparison between the losses used in Statement L for the development of the AED demands and the losses used by the Company in developing 12 CP demand (LCG-010). I have corrected the Company's 12 CP demands by using the losses from Statement L for Rates 20, 31, and 35.

Table 2
Comparison of Loss Factors: Statement L vs. MDU Response to LCG-010

		Statement L*		LCG-010	
		Energy (%)	Demand (%)	Energy (%)	Demand (%)
Residential	Rate 10	7.74%	12.98%	7.74%	12.98%
Small General Primary		6.92%	10.66%		
Small General Secondary		7.74%	12.98%		
Small General Composite	Rate 20	7.73%	12.98%	7.74%	12.98%
Irrigation Power	Rate 25	7.74%	12.98%	7.74%	12.98%
Large General Primary	Rate 30	6.92%	10.66%	6.92%	10.66%
Large General Secondary	Rate 30	7.74%	12.98%	7.74%	12.98%
Optional TOD Lg Gen Prim		6.92%	10.66%		
Optional TOD Lg Gen Sec		7.74%	12.98%		
Optional TOD Large General	Rate 31	6.95%	10.95%	6.92%	10.66%
Contract Services	Rate 35	6.26%	8.65%	6.92%	10.66%
Municipal Pumping	Rate 48	7.74%	12.98%	7.74%	12.98%
Outdoor Lighting	Rate 52	7.74%	12.98%	7.74%	12.98%
Street Lighting - Company		7.74%	12.98%		
Street Lighting - Municipal		7.74%	12.98%		
Street Lighting	Rate 41	7.74%	13.01%	7.74%	12.98%
Secondary	Rate 32	7.74%	12.98%	7.74%	12.98%

* Statement L excel workbook, TAB "energy & demand - AED."

Exhibit SJB-5 presents the results of my corrected 12 CP allocation factors for each rate class, as well as a comparison to the Company's 12 CP factors provided in response to LCG-010. Also included are the Company's AED factors. As can be seen, for Rate 35 there is a significant disparity between the AED factor and the 12 CP factor.

Q. SHOULD THE COMMISSION RELY ON MDU'S AED COST STUDY IN THIS CASE?

A. No. I believe that the results of a 12 CP class cost of service study provide a more cost-based and, therefore, reasonable basis to apportion the revenue increase in this case. Exhibit SJB-6 presents the results of my 12 CP cost of service study. This analysis reflects all of the assumptions and inputs used in the Company's AED cost study, except that the AED allocator has been replaced by a 12 CP allocator. Table 3 below summarizes the rates of returns from the 12 CP study under current rates, compared to the Company's AED cost study. The columns labeled "Index" contain the relative rates of return for each rate class (class ROR divided by Total Montana ROR).

Table 3
Class Cost of Service Results
12 CP vs. AED

		AED as filed	Index	12 CP	Index
Residential	Rate 10	2.20%	0.62	1.81%	0.51
Small General	Rate 20	4.26%	1.21	2.97%	0.84
Irrigation Power	Rate 25	(4.22%)	(1.20)	(1.19%)	(0.34)
Large General Primary	Rate 30	1.76%	0.50	5.37%	1.52
Large General Secondary	Rate 30	5.86%	1.66	3.87%	1.10
Optional TOD Large General	Rate 31	5.42%	1.54	5.33%	1.51
Contract Services	Rate 35	3.54%	1.00	6.17%	1.75
Municipal Pumping	Rate 48	(0.02%)	(0.01)	2.74%	0.78
Outdoor Lighting	Rate 52	1.44%	0.41	1.68%	0.48
Street Lighting	Rate 41	5.91%	1.67	6.61%	1.87
Secondary	Rate 32	2.18%	0.62	1.69%	0.48
Total Montana		3.53%	1.00	3.53%	1.00

As can be seen from Table 3, the impact on Rate 35 is significant. While even the Company's AED cost study showed that Rate 35 is currently at cost of service, the 12 CP study shows that Rate 35 is significantly above cost of service. And although the 12 CP study shows that the residential rate of return is somewhat lower than under the Company's AED method, the results are not significantly different.

I believe that the substantial increase in the Rate 35 earned rate of return at present rates demonstrates that there is a problem with the Company's AED analysis. Essentially, the Company's proposal increases the cost allocation to Rate 35 because of off-peak usage and decreases the cost allocation to classes that are using on peak. This approach is exactly backwards from a cost-causation perspective and would result in a flawed price signal to both Rate 35 and the other customer classes. The results of the 12 CP study provide a more accurate measure of cost responsibility and should be relied on to apportion the approved revenue increase in this case.

C. <u>Other concerns and recommendations regarding MDU's cost of service analysis.</u>

Q. YOU INDICATED EARLIER THAT YOU HAVE IDENTIFIED OTHER PROBLEMS WITH THE COMPANY'S COST OF SERVICE ANALYSIS THAT ARE UNRELATED TO THE AED ALLOCATOR ISSUE. WOULD YOU DISCUSS THESE PROBLEMS?

A. Yes. The first issue concerns the Company's classification of wind facilities as 83.5% energy, 16.5% demand. Since the Company's AED factor implicitly classifies 76% of wind demand costs as energy related (average demand), the effect of the Company's treatment of wind costs is to allocate 96% on the basis of energy, 4% on excess demand.[7] The Company based its wind cost classification on MISO wind capacity credit percentage, which credits wind mW at 16.5% of the nameplate mW rating of MDU's wind generators. The problem with the Company's 83.5% energy classification is that

[7] Wind energy allocation is as follows: 83.5% + (76% X 16.5%) = 96%.

MDU is equating the percentage split between MISO wind capacity mW and wind capacity nameplate mW (16.5%) with the percentage split of the costs of the wind facilities between demand and energy. These are not the same.

Q. CAN YOU EXPLAIN WHY THIS ENERGY/DEMAND CLASSIFICATION IS NOT APPROPRIATE?

A. Yes. Assume that the Company has a 100 kW wind generator that costs $100,000. If MISO credits this wind capacity using a 16.5% factor, then the Company receives 16.5 kW of MISO capacity credit for the generator. All that is known from this analysis is that the Company spent $100,000 and received 16.5 kW of capacity. The cost of capacity is thus $6,060 per kW. The fact that MISO credits the capacity at 16.5% of its nameplate kW rating doesn't change the fact that the Company has capacity that effectively costs $6,060 per kW – there is no information regarding the energy value of the capacity in this illustration, or in the Company's wind facility energy/demand split.

Q. HOW SHOULD THE COSTS OF WIND FACILITIES BE CLASSIFIED IN A COST OF SERVICE STUDY?

A. While it is true that wind facilities receive MISO capacity credits of only 16.5% of nameplate mW rating, a 16.5% demand classification is unreasonably low. In the test year in this case, MDU's wind facilities had an average cost of $60.92/mWh. The basis for this computation is shown in Exhibit SJB-7, which uses the wind facility revenue requirements included in the Company's class cost of service study. A reasonable measure of the energy value of these wind facilities is the average price of MISO energy purchases that the Company made during the test year, which is $29.70/mWh.[8] The costs

[8] Company workpaper G-35 provides the MISO purchase energy price.

in excess of $29.70/mWh represent the amount of fixed costs that are not energy related. As shown on Exhibit SJB-7, this produces an energy classification of the Company's wind facilities of 48.7%. The remaining 51.3% of the wind facility costs are demand related.

Q. WOULD YOU DISCUSS THE SECOND PROBLEM THAT YOU HAVE IDENTIFIED WITH THE COMPANY'S COST OF SERVICE ANALYSIS?

A. Yes. In its class cost of service study, the Company separately allocated Pro Forma Adjustments to rate classes. It appears that the Company incorrectly allocated the Pro Forma Adjustment for Other Production O&M expenses. The Pro Forma Adjustment amount of these costs should be allocated to rate classes using the same allocation factor as is used for the book level of these Other Production O&M expenses. The Company allocates Other Production O&M expenses using the AED demand allocator (Factor 2). However, for the Pro Forma Adjustment amount of Other Production O&M expenses, the Company uses an allocator based on the allocation of Total Production O&M (Factor 47), which includes all production O&M expenses, including Fuel and Purchased Power expense, which is related to mWh energy, not demand. The end result is an error in the allocation of the Pro Forma Adjustment amounts to rate classes. Table 4 below is an excerpt from the Statement L excel workbook, Tab "Embedded CCOS – Details" that shows the Company's allocation factor assignment.

Table 4
Excerpt From Class Cost of Service Study - Expense Allocation Factors

	Allocation Factor	Total Montana
Production Expense		
F&PP - Energy	Direct	20,985,800
F&PP - Demand	Direct	955,056
F&PP - Non-Fuel Expenses	1	370,794
Other Production	2	5,350,825
Total Production Expense		27,662,475
Pro Forma Adjustments - Operating Income		
Operation & Maintenance Expenses		
Other O&M		
F&PP - Non-Fuel Expense	1	6,356
Production	47	1,666,202
Transmission	2	1,178,969
Distribution	21	107,716
Customer Accounts	12	9,797
Customer Service & Information	12	458
Sales	8.2	(10,036)
Administrative & General	24	494,349
Total Other O&M - Adj. 5 - 29		3,453,811
Total Adjustments to O&M		1,643,868

Q. HOW DID YOU CORRECT THIS ERROR?

A. I changed the basis of allocation Factor 47 to be equal to the allocation of Other Production O&M.

Q. HAVE YOU DEVELOPED ALTERNATIVE AED AND 12 CP COST OF SERVICE STUDIES REFLECTING YOUR RECOMMEND ADJUSTMENTS?

A. Yes. Exhibits SJB-8 and SJB-9 contain the results of these analyses. The AED cost study presented in Exhibit SJB-8 is identical to the Company's filed AED cost study except for the two adjustments that I made for wind generation cost classification and the production O&M expense allocation issue that I discussed. The alternative AED study in Exhibit SJB-8 also utilizes the 2014 MDU Montana peak demand in the development of the AED factor instead of the Company's three-year average July peak calculation.

With regard to the 12 CP cost study presented in Exhibit SJB-9, this study is identical to my 12 CP study shown in Exhibit SJB-6 except for the wind cost classification change and the correction to the production O&M expense allocation. Table 5 below summarizes the rates of return from each of the studies (under current rates).

Table 5
Class Cost of Service Results
12 CP vs. AED w/Adjustments

		Adjusted AED	Index	Adjusted 12 CP	Index
Residential	Rate 10	1.961%	0.556	1.764%	0.500
Small General	Rate 20	4.169%	1.182	2.883%	0.817
Irrigation Power	Rate 25	(4.367%)	(1.238)	(1.183%)	(0.335)
Large General Primary	Rate 30	1.262%	0.358	5.510%	1.562
Large General Secondary	Rate 30	6.116%	1.734	3.789%	1.074
Optional TOD Large General	Rate 31	4.981%	1.412	5.209%	1.476
Contract Services	Rate 35	4.209%	1.193	6.784%	1.923
Municipal Pumping	Rate 48	(0.370%)	(0.105)	2.806%	0.795
Outdoor Lighting	Rate 52	1.422%	0.403	1.688%	0.478
Street Lighting	Rate 41	5.863%	1.662	6.672%	1.891
Secondary	Rate 32	2.104%	0.596	1.660%	0.471
Total Montana		3.528%	1.000	3.528%	1.000

D. <u>Concerns and recommendations regarding revenue apportionment.</u>

Q. BASED ON THE RESULTS OF YOUR RECOMMENDED 12 CP CLASS COST OF SERVICE STUDY, IS THE COMPANY'S PROPOSED RATE CLASS REVENUE APPORTIONMENT IN THIS CASE REASONABLE?

A. No. The Company is proposing a uniform percentage increase for each rate class of 21.1%. As discussed by MDU witness Tamie Aberle, the Company decided to increase each rate class by the same percentage due to 1) the results of the embedded AED cost of service study, 2) the results of the marginal cost study, and 3) the magnitude of the overall revenue increase being requested by the Company in this case.

Q. DO YOU AGREE WITH THE COMPANY THAT A UNIFORM PERCENTAGE INCREASE TO EACH RATE CLASS IS JUSTIFIED IN THIS CASE?

A. No. First, notwithstanding Ms. Aberle's testimony that she relied on the results of both the embedded and marginal cost studies, the Company confirmed in its response to LCG-005 that it primarily relied on the embedded cost of service study to apportion the revenue increase to rate classes, not the marginal cost study.[9] I agree with this position. Since the Company's marginal cost study does not produce rates that would equate to the requested revenue requirement, the marginal cost rates had to be uniformly scaled-back. Once a uniform scale-back is performed, the resulting rates are no longer marginal cost rates, regardless of the quality of the underlying marginal cost study.

However, though I agree with the Company that the embedded cost of service study should be relied on to apportion the increase in this case, the AED cost study is not a reasonable measure of cost responsibility. For the purposes of apportioning the approved revenue increase in this case, the 12 CP cost study that I developed is more reasonable and indicative of cost responsibility.

Q. WHAT DOES THE 12 CP COST STUDY INDICATE WITH REGARD TO AN APPROPRIATE APPORTIONMENT OF THE INCREASE TO RATE CLASSES?

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[9] *See* Exhibit SJB-10 for a copy of the response to LCG-005.

A. Table 6 below shows the percentage increases to each rate class at full 12 CP cost of service using the results of my adjusted 12 CP study [Exhibit SJB-9], which reflects the Company's requested $11,755,752 overall revenue increase. These are the increases to each rate class that contain no subsidy. As can be seen, the percentage increases range from 3.3% to 54.6%, based on an overall 21.1% Total Montana Electric increase.

Table 6
Class Revenue Increases at Cost of Service - 12 CP Cost Study

		Sales Revenue before Increase	Required Increases at Equal ROR 12 CP Cost of Service $	%
Residential	Rate 10	$ 16,905,175	$ 5,483,376	32.4%
Small General	Rate 20	$ 10,282,740	$ 2,713,322	26.4%
Irrigation Power	Rate 25	$ 202,269	$ 110,439	54.6%
Large General Primary	Rate 30	$ 2,860,951	$ 268,791	9.4%
Large General Secondary	Rate 30	$ 11,107,441	$ 2,308,221	20.8%
Optional TOD Large General	Rate 31	$ 1,123,918	$ 135,497	12.1%
Contract Services	Rate 35	$ 11,694,833	$ 387,605	3.3%
Municipal Pumping	Rate 48	$ 463,309	$ 119,158	25.7%
Outdoor Lighting	Rate 52	$ 363,344	$ 179,909	49.5%
Street Lighting	Rate 41	$ 538,071	$ 26,740	5.0%
Secondary	Rate 32	$ 62,764	$ 22,501	35.9%
Total Montana		$ 55,604,814	$ 11,755,543	21.1%

E. <u>Proposal to mitigate rates based on cost of service.</u>

Q. ARE YOU RECOMMENDING THE INCREASES IN TABLE 6?

A. No. First, these increases reflect that Company's full revenue increase request in this case. LCG witnesses Kevin Higgins and Michael Gorman have recommended adjustments to the Company's requested revenue deficiency that would result in a lower overall increase. In my opinion, the Commission is likely to approve an overall increase lower than the Company's request. Any recommended apportionment would have to be adjusted to reflect the Commission approved overall revenue increase.

Second, while it is reasonable and appropriate to set rates based on cost of service, without subsidies paid from some rate classes to other classes, the magnitude of the potential increase at issue in this case warrants that some level of gradualism be employed to mitigate the impacts. However, it is appropriate to recognize cost responsibility in the revenue apportionment process and to minimize the subsidies among rate classes.

Q. WHAT IS YOUR SPECIFIC MITIGATION PROPOSAL?

A. I recommend that no rate class receive a percentage increase more than 1.5 times the system average. This approach moves all customer classes closer to cost of service to reduce cross-subsidies while acknowledging that gradualism and the avoidance of rate shock are reasonable public policy considerations. Table 7 presents the results of this mitigation "cap" methodology. The 12 CP revenue increases for each class are compared to an increase cap set equal to 1.5 times the average 21.1% increase (the cap results in a maximum increase of 31.7%). Any amount in excess of this cap increase is allocated proportionately to each of the non-capped rate classes to determine the "Adjustment" for each of these classes. The total increase to each rate class is the full cost based increase, minus the "excess," plus the adjustment (if applicable).

Table 7
Mitigated Class Revenue Increases at Cost of Service - 12 CP Cost Study

			12 CP Cost of Service		Mitigation				
		Sales Revenue	Required Incr at Eq. ROR		CAP @		0.620%	Mitigated	
	Rate	before Increase	$	%	31.7%	Excess	Adjustment	Increase	%
Residential	10	$ 16,905,175	$ 5,483,376	32.4%	$ 5,360,951	$ 122,425	0	$ 5,360,951	31.7%
Small General	20	$ 10,282,740	$ 2,713,322	26.4%	$ 3,260,851	$ -	63,743	$ 2,777,065	27.0%
Irrigation Power	25	$ 202,269	$ 110,439	54.6%	$ 64,143	$ 46,296	-	$ 64,143	31.7%
Large General Pri	30	$ 2,860,951	$ 268,791	9.4%	$ 907,262	$ -	17,735	$ 286,526	10.0%
Large General Sec	30	$ 11,107,441	$ 2,308,221	20.8%	$ 3,522,380	$ -	68,855	$ 2,377,076	21.4%
Optional TOD LG	31	$ 1,123,918	$ 135,497	12.1%	$ 356,416	$ -	6,967	$ 142,464	12.7%
Contract Services	35	$ 11,694,833	$ 387,605	3.3%	$ 3,708,653	$ -	72,496	$ 460,101	3.9%
Municipal Pumpin	48	$ 463,309	$ 119,158	25.7%	$ 146,924	$ -	2,872	$ 122,030	26.3%
Outdoor Lighting	52	$ 363,344	$ 179,909	49.5%	$ 115,223	$ 64,686	-	$ 115,223	31.7%
Street Lighting	41	$ 538,071	$ 26,740	5.0%	$ 170,632	$ -	3,336	$ 30,076	5.6%
Secondary	32	$ 62,764	$ 22,501	35.9%	$ 19,904	$ 2,597	-	$ 19,904	31.7%
Total Montana		$ 55,604,814	$11,755,559	21.1%	$ 17,633,339	$ 236,004	236,004	$ 11,755,559	21.1%

Q. IF THE COMMISSION APPROVES AN OVERALL REVENUE INCREASE LOWER THAN THE $11.8 MILLION REQUESTED BY THE COMPANY, HOW SHOULD THE RESULTS IN TABLE 7 BE ADJUSTED?

A. I recommend that the dollar increase shown in Table 7 be scaled-back on a uniform percentage basis so that the total increase matches the Commission approved revenue increase. For example, based on the overall revenue increase recommended by LCG witnesses Higgins and Gorman of $2,437,539, the increases shown in Table 7 would be scaled-back by 79%. Table 8 illustrates the rate class increases based on the LCG recommended overall revenue increase in this case.

Table 8
Illustration of Recommended Class Revenue Increases
Based on LCG Proposed Revenue Increase

	Rate	Mitigated Increase	%	LCG Recommended Increase	Scaled-Back Increases	%
Residential	10	$ 5,360,951	31.7%		$1,111,604	6.6%
Small General	20	$ 2,777,065	27.0%		$ 575,830	5.6%
Irrigation Power	25	$ 64,143	31.7%		$ 13,300	6.6%
Large General Pri	30	$ 286,526	10.0%		$ 59,412	2.1%
Large General Sec	30	$ 2,377,076	21.4%		$ 492,892	4.4%
Optional TOD LG	31	$ 142,464	12.7%		$ 29,540	2.6%
Contract Services	35	$ 460,101	3.9%		$ 95,403	0.8%
Municipal Pumping	48	$ 122,030	26.3%		$ 25,303	5.5%
Outdoor Lighting	52	$ 115,223	31.7%		$ 23,892	6.6%
Street Lighting	41	$ 30,076	5.6%		$ 6,236	1.2%
Secondary	32	$ 19,904	31.7%		$ 4,127	6.6%
Total Montana		$11,755,559	21.1%	$ 2,437,539	$2,437,539	4.4%

III. RATE DESIGN AND RIDER ISSUES

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S PROPOSED TRANSMISSION COST RECOVERY RIDER ("TCRR")?

A. The TCRR is designed to recover capital costs and operating expenses associated with new transmission investments. The proposed rider states its purpose as follows:

> This rate schedule represents a Transmission Cost Recovery Rider (TCRR) and specifies the procedure to be utilized to recover the capital and operating costs associated with transmission related investments and expenditures. Costs to be recovered under the TCRR shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

Q. DOES THIS INDICATE THAT THE COSTS THAT WILL BE RECOVERED FROM THE TCRR WILL BE THE SAME TYPE OF COSTS THAT ARE INCLUDED IN BASE RATE TRANSMISSION RELATED FACILITIES AND EXPENSES?

A. Yes. As discussed in Ms. Cardwell's Direct Testimony at page 5, transmission plant and related facilities are demand related and allocated to rate classes using the AED allocator. Transmission expenses are also allocated using the AED allocator. There are no transmission related costs classified and allocated on the basis of kWh energy in the class cost of service study, reflecting the underlying cost characteristics of transmission facilities.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER TRANSMISSION COSTS IN THE TCRR?

A. The proposed TCRR would recover all transmission costs through a single, uniform ¢/kWh charge, applicable to all rate schedules. The specific tariff states as follows:

> a. **An adjustment per Kwh** will be determined based on the cumulative transmission related costs eligible for recovery and as allocated to the Montana jurisdiction as of September 30 of each year and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

These TCRR costs are being recovered on a uniform ¢/kWh energy basis from all customers, without any recognition to the underlying character of the costs or differences in losses among the Company's various rate classes.

Q. IS THE TCRR UNIFORM KWH RECOVERY MECHANISM REASONABLE?

A. No. Notwithstanding the LCG's concerns with the mechanism in general as discussed by Mr. Higgins, if the TCRR is approved, the rate recovery should be on the basis of an allocation of the TCRR revenue requirement to rate classes on the basis of a demand allocation factor (AED, 12 CP, or 4 CP) that also reflects voltage differences among rate classes. Within demand metered rate classes, such as Rate 30 or Rate 35, the TCRR charge should be stated on a $/kW basis. For non-demand metered rate classes, such as the residential class, the charge should be on a ¢/kWh basis.

Q. IN RESPONSE TO PSC-032, THE COMPANY PROVIDED A COPY OF ITS TRANSMISSION COST RECOVERY RIDER IN ITS NORTH DAKOTA JURISDICTION. HOW DOES MDU RECOVER TRANSMISSION COSTS IN THIS TARIFF?

A. In its North Dakota jurisdiction, the Company's Transmission Cost Adjustment, Rate 59, allocates transmission costs to rate classes using the "transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case." A copy of MDU's response to PSC-032 is attached as Exhibit SJB-11. This is consistent with my recommendation in this case to allocate transmission costs in the TCRR on the basis of a demand allocation factor (if the TCRR is approved by the Commission).

Q. IS YOUR RECOMMENDATION CONSISTENT WITH THE TREATMENT OF COSTS IN THE ENVIRONMENTAL COST RECOVERY RIDER?

A. Yes, in part. In the ECRR, the Company is proposing to allocate costs to rate classes on the basis of the production demand allocation factor (AED factor 2), as approved in the most recent class cost of service study. However, the Company then proposes to recover the allocated costs within each rate class on a uniform ¢/kWh basis. My proposal differs somewhat in that costs within a rate class should be recovered on a $/kW demand basis for demand metered rate classes, rather than on a ¢/kWh basis within the rate class.

Q. DO YOU RECOMMEND A SIMILAR RATE DESIGN FOR THE RECOVERY OF ECRR COSTS, IF THE COMPANY'S PROPOSED ECRR TARIFF IS APPROVED?

A. Yes. Within demand metered rate classes, such as Rate 30, the ECRR charge should be recovered from customers on a $/kW basis, reflecting the underlying cost characteristics of the charge. For non-demand metered rate classes, a ¢/kWh recovery basis is appropriate (if the Commission approves the tariff).

Q. DOES THE COMPANY AGREE THAT A $/KW RECOVERY RATE WOULD BE APPROPRIATE FOR THE ECCR AND TCCR CHARGES FOR DEMAND METERED RATE CLASSES?

A. Yes. Exhibit SJB-12 contains the Company's response to LCG-75 and LCG-76, which confirm the Company's position that it would be appropriate to recover the costs on a demand basis from demand metered classes.

Q. MDU WITNESS TRAVIS JACOBSON DISCUSSES THE COMPANY'S PROPOSAL TO RECOVER ITS DEFERRED COSTS ASSOCIATED WITH CHANGES IN THE PSC TAX RATE AND THE MCC TAX RATE. DO HAVE ANY CONCERNS WITH THE COMPANY'S PROPOSAL?

A. Yes. First, LCG witness Kevin Higgins addresses the Company's proposal to recover these deferred costs in a single year and recommends they be recovered over a three-year period instead. My concern is with the Company's proposed mechanism for recovery of any deferred costs. Mr. Jacobson proposes that the deferred costs be recovered on a uniform ¢/kWh basis through the fuel and purchased power tracker. However, since these taxes are charged to MDU as a percentage fee on gross operating revenue, the underlying cost basis for the taxes are customer revenues, not kWh usage.[10] A reasonable recovery mechanism should follow the cost basis for the incurrence of the cost by MDU, which means that the deferred costs should be recovered on a uniform percentage factor applied to customer base rate revenues. If you do otherwise, customer classes with

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[10] See Jacobson Direct Testimony on page 24 at lines 15-16. Also see Exhibit SJB-13, which contains a description of the "Consumer Counsel and Public Service Fees."

higher load factors, like Rate 35, will be unfairly paying more of the tax than they would have paid had these amounts been assessed correctly in the first instance. To implement this percentage recovery factor, a separate "Deferred PSC/MCC Tax Recovery Rate" can be established as part of the Company's tariff.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Direct Testimony of

Stephen J. Baron

Exhibit SJB-1

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of	Chamber of	Santa Clara	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
		Santa Clara	Commerce	Municipal	
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy	Indiana & Michigan	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
			Consumers	Power Co.	
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171- EL-AIR 88-170- EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171- EL-AIR 88-170- EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp.,	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

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Date	Case	Jurisdict.	Party	Utility	Subject
			Allegheny Ludlum Corp.		
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91 Note: No testimony was prefiled on this.	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.

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Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.
08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.

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Date	Case	Jurisdict.	Party	Utility	Subject
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.

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03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues

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Date	Case	Jurisdict.	Party	Utility	Subject
	P-00062214		Alliance		
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to

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2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Rate Schedules Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan

Expert Testimony Appearances
of
Stephen J. Baron
As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011 -00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011- 00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1274 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost “ENEC” Analysis.
11/11	E-01345A- 11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A- 11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues

Expert Testimony Appearances
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As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
7/13	13-0462- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764- E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013- 2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064- E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
5/14	14-0345- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service

Expert Testimony Appearances
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As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
7/14	PUE-2014 -00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014 -00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues
9/14	14-841-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost (“ENEC”)
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 El-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
615	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues

Expert Testimony Appearances
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As of October 2015

Date	Case	Jurisdict.	Party	Utility	Subject
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Non-Utility Generator Issues

Direct Testimony of

Stephen J. Baron

Exhibit SJB-2

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
CLASS COST OF SERVICE STUDY
12 Months Ending December 31, 2014
Demand and Energy Responsibility

			Class Level At Meter					Class Level At Supply						
Rate		Customer Class	Pro Forma KWH Sales	Load Factor (%)	Peak NCP KW	Loss Factors Energy (%)	Loss Factors Demand (%)	Energy @ Generation KWH	Average Demand KW	Peak NCP KW	Excess Demand KW	Class % Excess Demand	Allocated Excess Demand	Average & Excess Demand
		Residential												
10	-	Residential Electric Service	195,240,541	35.38%	62,995	7.74%	12.98%	211,608,455	24,156	72,391	48,235	39.87%	12,425	36,581
20	-	Small General Electric Service												
		Primary	94,018	43.98%	24	6.92%	10.66%	101,008	12	27	15	0.01%	3	15
		Secondary	128,375,906	43.98%	33,321	7.74%	12.98%	139,138,250	15,883	38,291	22,408	18.51%	5,768	21,651
		Total Rate 20	128,469,924		33,345			139,239,258	15,895	38,318	22,423	18.52%	5,771	21,666
25	-	Irrigation Power Service	2,885,435	14.06%	2,343	7.74%	12.98%	3,127,334	357	2,692	2,335	1.93%	601	958
		Total Small General	131,355,359		35,688			142,366,592	16,252	41,010	24,758	20.45%	6,372	22,624
30	-	Large General Electric Service												
		Primary	46,454,293	28.78%	18,426	6.92%	10.66%	49,907,921	5,697	20,625	14,928	12.33%	3,843	9,540
		Secondary	169,343,176	56.94%	33,950	7.74%	12.98%	183,539,995	20,952	39,014	18,062	14.92%	4,650	25,602
		Total Rate 30	215,797,469		52,376			233,447,916	26,649	59,639	32,990	27.25%	8,493	35,142
31	-	Optional TOD Large General Service												
		Primary	15,225,600	38.40%	4,526	6.92%	10.66%	16,357,542	1,867	5,066	3,199	2.64%	823	2,690
		Secondary	610,460	10.93%	638	7.74%	12.98%	661,638	76	733	657	0.54%	168	244
		Total Rate 31	15,836,060		5,164			17,019,180	1,943	5,799	3,856	3.18%	991	2,934
32	-	Rate 32 Secondary	1,048,759	43.98%	272	7.74%	12.98%	1,136,681	130	313	183	0.15%	47	177
35	-	Contract Service	228,554,425	82.35%	31,683	6.26%	8.65%	243,817,394	27,833	34,683	6,850	5.66%	1,764	29,597
		Total Large General	461,236,713		89,495			495,421,171	56,555	100,434	43,879	36.24%	11,295	67,850
48	-	Municipal Pumping	7,341,210	28.25%	2,967	7.74%	12.98%	7,956,657	908	3,410	2,502	2.07%	645	1,553
52	-	Outdoor Lighting Service	3,237,499	45.66%	809	7.74%	12.98%	3,508,913	401	930	529	0.44%	137	538
41	-	Street Lighting Service												
		Company Owned	6,080,236	45.66%	1,520	7.74%	12.98%	6,589,970	752	1,747	995	0.82%	256	1,008
		Municipal Owned	818,000	45.55%	205	7.74%	12.98%	886,577	101	236	135	0.11%	34	135
		Total Rate 41	6,898,236		1,725			7,476,547	853	1,983	1,130	0.93%	290	1,143
		TOTAL MONTANA	805,309,558		193,679			868,338,335	99,125	220,158	121,033	100%	31,164	130,289

Hours in the Year	**8,760**
Montana Allocated Peak July 1/	**130,289**
Excess Demand to Allocate	**31,164**

1/ Peak based on the state of Montana using a three year average for July.

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Exhibit SJB-3

Demonstration that Class NCP for Rate 35 is Based on Billing KW					
	Response to MCC-125	Response to LCG-009		%	
Month	Billing KW	NCP KW	Difference	Difference
2014 January	30,836.7	30,752.2	85	0.27%
February	29,362.0	29,269.8	92	0.31%
March	31,646.0	31,556.2	90	0.28%
April	31,775.2	$\boxed{31,681.7}$	93	0.29%
May	30,364.8	30,364.8	-	0.00%
June	29,293.6	29,293.5	0	0.00%
July	28,789.8	28,789.8	-	0.00%
August	29,759.2	29,759.2	-	0.00%
September	30,211.5	30,211.5	-	0.00%
October	30,034.0	30,034.0	-	0.00%
November	30,690.1	30,690.1	-	0.00%
December	29,960.0	29,960.0	-	0.00%
Total	362,722.9	362,362.9	360	

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Exhibit SJB-4

MONTANA-DAKOTA UTILITIES CO.
HESKETT STATION - UNIT III: COMBUSTION TURBINE
ELECTRIC UTILITY - MONTANA
ADJUSTMENT NO. 8

	Pro Forma 1/		
	Total Company	Montana 2/	Adjustment
Labor	$79,394	$17,977	$17,977
Benefits	29,265	6,626	6,626
Subcontract Labor	110,500	25,020	25,020
Materials	104,500	23,662	23,662
Office Supplies	4,000	906	906
Permits and Filing Fees	8,200	1,857	1,857
Safety and Other Employee Training	12,000	2,717	2,717
	$347,859	$78,765	$78,765

1/ Pro forma represents increases to reflect a full-year of operations.
2/ Allocated on Factor 15: Integrated System Peak Demand.

MONTANA-DAKOTA UTILITIES CO.
LEWIS & CLARK STATION - RICE UNIT & MATS (ENVIRONMENTAL UPGRADE)
ELECTRIC UTILITY - MONTANA
ADJUSTMENT NO. 9

	Pro Forma 1/		
	Total Company	Montana 2/	Adjustment
Labor	$227,971	$51,619	$51,619
Benefits	84,030	19,027	19,027
Subcontract Labor	88,500	20,039	20,039
Materials	99,170	22,455	22,455
Office Supplies	2,000	453	453
Other Employee Training	10,000	2,264	2,264
	$511,671	$115,857	$115,857

1/ Pro forma represents increases to reflect a full-year of operations.
2/ Allocated on Factor 15: Integrated System Peak Demand.

MONTANA-DAKOTA UTILITIES CO.
BIG STONE AND COYOTE GENERATION UNITS
PRODUCTION OPERATING AND MAINTENANCE EXPENSES
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2014
ADJUSTMENT NO. 13

	Per Books 1/		Pro Forma 1/		
	Total Company	Montana	Total Company	Montana 2/	Adjustment
Big Stone	$3,455,445	$778,899	$5,727,270	$1,293,304	$514,405
Coyote	4,480,591	1,006,107	4,775,350	1,072,849	66,742
	$7,936,036	$1,785,006	$10,502,620	$2,366,153	$581,147

1/ Excludes Cost of Fuel and Reagent.
2/ Allocated on Factor 15: Integrated System Peak Demand.

MONTANA-DAKOTA UTILITIES CO.
ALLOCATION FACTORS - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2014

Federal Tax Rate	35.00%	
State Tax Rate	6.75%	
Combined Federal & State Tax Rate =	39.3875%	
Inverse	60.6125%	
Inverse of tax rate for revenue increase	60.43066%	0.18184%
	39.56934%	
MCC Tax Rate =	0.1%	
PSC Tax Rate =	0.2%	
	0.3%	99.7%

Allocation Factors

	2014	2015
Factor 15-Integrated System 12 month Peak Demand	22.428695%	22.642790%
Factor 16-Integrated System Kwh Sales	27.270911%	26.537673%
Factor 26-O&M Excl Fuel, Purchased Power & A&G	20.212911%	19.068283%
Factor 271-Integrated Peak and Energy	26.302468%	25.758696%
Factor 18-Interconnected System Transmission Plant	19.220609%	18.085528%

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Exhibit SJB-5

Comparison of Demand Allocation Factors (Factor 2)
Corrected 12 CP vs. MDU 12 CP vs. AED

		Corrected 12 CP	MDU 12 CP (LCG-010)	AED As-Filed
Residential	Rate 10	29.79%	29.68%	28.08%
Small General	Rate 20	19.68%	19.61%	16.63%
Irrigation Power	Rate 25	0.40%	0.40%	0.74%
Large General Primary	Rate 30	4.94%	4.92%	7.32%
Large General Secondary	Rate 30	24.18%	24.09%	19.65%
Optional TOD Large General	Rate 31	2.27%	2.26%	2.25%
Contract Services	Rate 35	16.63%	16.94%	22.72%
Municipal Pumping	Rate 48	0.79%	0.79%	1.19%
Outdoor Lighting	Rate 52	0.37%	0.37%	0.41%
Street Lighting	Rate 41	0.80%	0.79%	0.88%
Secondary	Rate 32	0.14%	0.14%	0.14%
Total Montana		100%	100%	100%

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Exhibit SJB-6

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Operating Income and Rate of Return							
Operating Sales Revenues	55,454,439	16,960,743	10,037,000	198,790	2,834,317	11,109,096	1,117,488
Adjustments to Sales Revenues	150,375	(55,570)	245,741	3,479	26,634	(1,655)	6,430
Total Sales Revenues	55,604,814	16,905,173	10,282,741	202,269	2,860,951	11,107,441	1,123,918
Other Revenues	2,739,123	762,114	445,167	10,694	102,944	466,583	43,965
Adjustments to Other Revenues	(516,834)	(170,421)	(95,997)	(2,302)	(24,508)	(99,896)	(9,401)
Total Other Revenues	2,222,289	591,693	349,170	8,392	78,436	366,687	34,564
Total Operating Revenues	57,827,103	17,496,866	10,631,911	210,661	2,939,387	11,474,128	1,158,482
Operating Expense							
Cost of Fuel and Purchased Power	22,311,651	5,489,002	3,612,510	80,781	1,274,675	4,745,021	440,270
Adj. to Cost of Fuel and Purchased Pwr	(1,809,945)	(485,102)	(319,815)	(6,881)	(97,488)	(407,237)	(37,997)
Total Cost of Fuel and Purchased Pwr	20,501,706	5,003,900	3,292,695	73,900	1,177,187	4,337,784	402,273
Other O&M Expense	15,814,584	6,324,551	3,264,871	81,444	620,195	2,823,464	269,474
Adjustments to Other O&M	3,453,813	1,038,815	640,918	14,370	173,582	745,115	69,955
Total Other O&M Expense	19,268,397	7,363,366	3,905,789	95,814	793,777	3,568,579	339,429
Total Operation & Maintenance Expense	39,770,103	12,367,266	7,198,484	169,714	1,970,964	7,906,363	741,702
Depreciation Expense	6,901,086	2,339,818	1,350,588	34,652	310,078	1,366,919	128,454

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Adjustment to Depreciation Expense	4,608,083	1,369,196	843,868	21,154	232,944	954,676	89,113
Total Depreciation Expense	11,509,169	3,709,014	2,194,456	55,806	543,022	2,321,595	217,567
Taxes Other Than Income Taxes	4,080,301	1,773,238	891,686	31,043	141,251	585,509	55,342
Adjustment to Taxes Other Than Income	617,223	218,719	125,198	3,465	26,872	119,706	11,252
Total Taxes Other Than Income	4,697,524	1,991,957	1,016,884	34,508	168,123	705,215	66,594
Current Income Taxes - Fed. & State	(4,064,986)	(1,816,930)	(956,173)	(47,607)	(122,030)	(713,541)	(37,076)
Adjustment to Current Income Taxes	(13,304,336)	(3,828,600)	(2,334,868)	(54,120)	(682,806)	(2,928,662)	(271,055)
Total Current Income Taxes	(17,369,322)	(5,645,530)	(3,291,041)	(101,727)	(804,836)	(3,642,203)	(308,131)
Deferred Income Taxes	5,966,981	2,104,310	1,212,767	33,817	260,000	1,164,704	109,305
Adjustment to Deferred Income Tax	7,080,843	1,960,903	1,291,942	27,500	372,143	1,624,393	151,862
Total Deferred Income Taxes	13,047,824	4,065,213	2,504,709	61,317	632,143	2,789,097	261,167
Total Operating Expenses	51,655,298	16,487,920	9,623,492	219,618	2,509,416	10,080,067	978,899
Pro Forma Operating Income	6,171,805	1,008,946	1,008,419	(8,957)	429,971	1,394,061	179,583
Rate Base	87,013,107	31,128,909	18,109,091	314,637	3,181,215	16,463,804	1,546,082
Adjustment to Rate Base	87,944,244	24,490,697	15,884,588	435,767	4,825,825	19,536,197	1,822,576
Total Pro Forma Rate Base	174,957,351	55,619,606	33,993,679	750,404	8,007,040	36,000,001	3,368,658
Pro Forma Rate of Return	3.528%	1.814%	2.966%	-1.194%	5.370%	3.872%	5.331%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Operating Income and Rate of Return						
Operating Sales Revenues	55,454,439	11,764,497	465,178	364,359	540,358	62,615
Adjustments to Sales Revenues	150,375	(69,664)	(1,869)	(1,015)	(2,287)	149
Total Sales Revenues	55,604,814	11,694,833	463,309	363,344	538,071	62,764
Other Revenues	2,739,123	353,019	18,569	184,855	348,285	2,928
Adjustments to Other Revenues	(516,834)	(98,272)	(4,354)	(4,464)	(6,577)	(642)
Total Other Revenues	2,222,289	254,747	14,215	180,391	341,708	2,286
Total Operating Revenues	57,827,103	11,949,580	477,524	543,735	879,779	65,050
Operating Expense						
Cost of Fuel and Purchased Power	22,311,651	6,155,429	203,242	89,880	191,504	29,337
Adj. to Cost of Fuel and Purchased Pwr	(1,809,945)	(415,233)	(15,563)	(7,076)	(15,072)	(2,481)
Total Cost of Fuel and Purchased Pwr	20,501,706	5,740,196	187,679	82,804	176,432	26,856
Other O&M Expense	15,814,584	1,837,823	123,698	195,907	254,325	18,832
Adjustments to Other O&M	3,453,813	682,167	28,975	21,010	34,270	4,636
Total Other O&M Expense	19,268,397	2,519,990	152,673	216,917	288,595	23,468
Total Operation & Maintenance Expense	39,770,103	8,260,186	340,352	299,721	465,027	50,324
Depreciation Expense	6,901,086	1,079,764	58,423	99,361	124,382	8,647

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Adjustment to Depreciation Expense	4,608,083	957,920	41,006	37,772	54,516	5,918
Total Depreciation Expense	11,509,169	2,037,684	99,429	137,133	178,898	14,565
Taxes Other Than Income Taxes	4,080,301	357,938	38,635	99,196	102,442	4,021
Adjustment to Taxes Other Than Income	617,223	88,006	5,398	8,090	9,763	754
Total Taxes Other Than Income	4,697,524	445,944	44,033	107,286	112,205	4,775
Current Income Taxes - Fed. & State	(4,064,986)	(236,744)	(44,397)	(63,457)	(19,362)	(7,669)
Adjustment to Current Income Taxes	(13,304,336)	(2,866,803)	(116,018)	(76,543)	(126,949)	(17,912)
Total Current Income Taxes	(17,369,322)	(3,103,547)	(160,415)	(140,000)	(146,311)	(25,581)
Deferred Income Taxes	5,966,981	848,098	52,450	80,627	93,603	7,300
Adjustment to Deferred Income Tax	7,080,843	1,496,161	59,536	27,882	58,677	9,844
Total Deferred Income Taxes	13,047,824	2,344,259	111,986	108,509	152,280	17,144
Total Operating Expenses	51,655,298	9,984,526	435,385	512,649	762,099	61,227
Pro Forma Operating Income	6,171,805	1,965,054	42,139	31,086	117,680	3,823
Rate Base	87,013,107	12,999,056	761,484	1,420,431	981,229	107,169
Adjustment to Rate Base	87,944,244	18,827,960	774,064	429,266	798,289	119,015
Total Pro Forma Rate Base	174,957,351	31,827,016	1,535,548	1,849,697	1,779,518	226,184
Pro Forma Rate of Return	3.528%	6.174%	2.744%	1.681%	6.613%	1.690%

Direct Testimony of

Stephen J. Baron

Exhibit SJB-7

Development of Wind Facility Energy/Demand Classification

Wind Production Plant	28,044,598		
Accumulated Depreciation	6,370,349		
Accum Depr - Adj C	1,364,888		
Net Electric Plant in Service	20,309,361		
Accum Deferred Inc Taxes *	(3,894,948)		
Rate Base	16,414,413		
Wind Generation Expansion	56,231,880		
Accumulated Depreciation	2,833,457		
Net Electric Plant in Service	53,398,423		
Accum Deferred Inc Taxes	(3,348,083)		
Rate Base	50,050,340		
Total Rate Base	66,464,754		
		Juris Factor	Total Rev Req
ROR Revenue Requirements	7,228,707	25.759%	28,063,170
Existing Plant O&M	328,549	25.759%	1,275,489
Expansion O&M - Adj 10	713,516	25.759%	2,770,000
Depreciation Expense	1,393,112	25.759%	5,408,317
Expansion Depreciation Exp - Adj 31	2,833,457	25.759%	11,000,002
Production Tax Credit	(978,193)	26.538%	(3,686,054)
Expansion Prod Tax Cred - Adj 39	(2,550,561)	26.538%	(9,611,095)
Net Revenue Requirements	8,968,587	12,497,341	35,219,829
mWh Wind Generation			578,137
Avg Cost per mWh			60.92
Average Cost of MISO Purchases			29.70
% Energy Allocation			48.7%

* Amount pro-rated by plant balance

Direct Testimony of

Stephen J. Baron

Exhibit SJB-8

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using AED Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Operating Income and Rate of Return							
Operating Sales Revenues	55,454,441	16,960,744	10,037,000	198,790	2,834,318	11,109,096	1,117,488
Adjustments to Sales Revenues	150,374	(55,570)	245,741	3,479	26,633	(1,655)	6,430
Total Sales Revenues	55,604,815	16,905,174	10,282,741	202,269	2,860,951	11,107,441	1,123,918
Other Revenues	2,739,124	749,760	399,508	17,389	146,628	389,459	44,825
Adjustments to Other Revenues	(516,833)	(168,755)	(90,408)	(3,101)	(29,763)	(90,563)	(9,493)
Total Other Revenues	2,222,291	581,005	309,100	14,288	116,865	298,896	35,332
Total Operating Revenues	57,827,106	17,486,179	10,591,841	216,557	2,977,816	11,406,337	1,159,250
Operating Expense							
Cost of Fuel and Purchased Power	22,311,651	5,480,705	3,584,678	84,761	1,300,840	4,698,549	440,729
Adj. to Cost of Fuel and Purchased Pwr	(1,809,944)	(478,049)	(296,156)	(10,263)	(119,730)	(367,733)	(38,388)
Total Cost of Fuel and Purchased Pwr	20,501,707	5,002,656	3,288,522	74,498	1,181,110	4,330,816	402,341
Other O&M Expense	15,814,581	6,231,993	2,954,380	125,836	912,092	2,305,020	274,600
Adjustments to Other O&M	3,453,814	1,076,051	594,393	27,688	248,203	631,533	75,093
Total Other O&M Expense	19,268,395	7,308,044	3,548,773	153,524	1,160,295	2,936,553	349,693
Total Operation & Maintenance Expense	39,770,102	12,310,700	6,837,295	228,022	2,341,405	7,267,369	752,034
Depreciation Expense	6,901,084	2,328,658	1,234,286	54,346	433,624	1,156,209	132,384

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using AED Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Adjustment to Depreciation Expense	4,608,074	1,398,247	800,166	32,889	299,457	852,150	93,433
Total Depreciation Expense	11,509,158	3,726,905	2,034,452	87,235	733,081	2,008,359	225,817
Taxes Other Than Income Taxes	4,080,302	1,761,270	844,977	37,975	186,345	506,141	56,280
Adjustment to Taxes Other Than Income	617,220	216,756	114,249	5,201	37,953	100,510	11,543
Total Taxes Other Than Income	4,697,522	1,978,026	959,226	43,176	224,298	606,651	67,823
Current Income Taxes - Fed. & State	(4,064,984)	(1,778,995)	(668,687)	(94,939)	(421,164)	(199,960)	(45,908)
Adjustment to Current Income Taxes	(13,304,333)	(3,907,664)	(2,168,048)	(94,770)	(917,469)	(2,559,644)	(284,824)
Total Current Income Taxes	(17,369,317)	(5,686,659)	(2,836,735)	(189,709)	(1,338,633)	(2,759,604)	(330,732)
Deferred Income Taxes	5,966,981	2,083,612	1,104,612	50,787	368,653	976,004	112,077
Adjustment to Deferred Income Tax	7,080,843	1,977,025	1,176,169	50,657	511,583	1,395,513	158,104
Total Deferred Income Taxes	13,047,824	4,060,637	2,280,781	101,444	880,236	2,371,517	270,181
Total Operating Expenses	51,655,289	16,389,609	9,275,019	270,168	2,840,387	9,494,292	985,123
Pro Forma Operating Income	6,171,817	1,096,570	1,316,822	(53,611)	137,429	1,912,045	174,127
Rate Base	87,013,103	31,050,021	16,877,043	528,409	4,513,760	14,204,012	1,591,085
Adjustment to Rate Base	87,944,243	24,871,513	14,708,312	699,355	6,373,699	17,058,307	1,904,556
Total Pro Forma Rate Base	174,957,346	55,921,534	31,585,355	1,227,764	10,887,459	31,262,319	3,495,641
Pro Forma Rate of Return	3.528%	1.961%	4.169%	-4.367%	1.262%	6.116%	4.981%
Increase at Equal Rate of Return	11,755,544	5,207,223	1,786,967	242,878	1,139,673	761,433	150,788
Percent	21.1%	30.8%	17.4%	120.1%	39.8%	6.9%	13.4%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using AED Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Operating Income and Rate of Return						
Operating Sales Revenues	55,454,441	11,764,497	465,178	364,359	540,358	62,615
Adjustments to Sales Revenues	150,374	(69,664)	(1,869)	(1,015)	(2,287)	149
Total Sales Revenues	55,604,815	11,694,833	463,309	363,344	538,071	62,764
Other Revenues	2,739,124	427,690	25,983	185,484	349,592	2,806
Adjustments to Other Revenues	(516,833)	(107,602)	(5,245)	(4,540)	(6,736)	(627)
Total Other Revenues	2,222,291	320,088	20,738	180,944	342,856	2,179
Total Operating Revenues	57,827,106	12,014,921	484,047	544,288	880,927	64,943
Operating Expense						
Cost of Fuel and Purchased Power	22,311,651	6,201,892	207,681	90,261	192,293	29,262
Adj. to Cost of Fuel and Purchased Pwr	(1,809,944)	(454,729)	(19,337)	(7,399)	(15,743)	(2,417)
Total Cost of Fuel and Purchased Pwr	20,501,707	5,747,163	188,344	82,862	176,550	26,845
Other O&M Expense	15,814,581	2,356,160	173,219	200,152	263,130	17,999
Adjustments to Other O&M	3,453,814	696,581	41,763	21,889	36,063	4,557
Total Other O&M Expense	19,268,395	3,052,741	214,982	222,041	299,193	22,556
Total Operation & Maintenance Expense	39,770,102	8,799,904	403,326	304,903	475,743	49,401
Depreciation Expense	6,901,084	1,244,819	79,440	101,062	127,899	8,357

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using AED Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Adjustment to Depreciation Expense	4,608,074	978,788	52,394	38,568	56,143	5,839
Total Depreciation Expense	11,509,158	2,223,607	131,834	139,630	184,042	14,196
Taxes Other Than Income Taxes	4,080,302	433,495	46,292	99,844	103,784	3,899
Adjustment to Taxes Other Than Income	617,220	104,672	7,280	8,245	10,084	727
Total Taxes Other Than Income	4,697,522	538,167	53,572	108,089	113,868	4,626
Current Income Taxes - Fed. & State	(4,064,984)	(657,555)	(95,266)	(67,612)	(27,957)	(6,941)
Adjustment to Current Income Taxes	(13,304,333)	(2,985,876)	(156,149)	(79,433)	(132,874)	(17,582)
Total Current Income Taxes	(17,369,317)	(3,643,431)	(251,415)	(147,045)	(160,831)	(24,523)
Deferred Income Taxes	5,966,981	1,014,365	70,913	82,160	96,777	7,021
Adjustment to Deferred Income Tax	7,080,843	1,626,761	83,318	29,705	62,429	9,579
Total Deferred Income Taxes	13,047,824	2,641,126	154,231	111,865	159,206	16,600
Total Operating Expenses	51,655,289	10,559,373	491,548	517,442	772,028	60,300
Pro Forma Operating Income	6,171,817	1,455,548	(7,501)	26,846	108,899	4,643
Rate Base	87,013,103	14,698,896	988,274	1,438,641	1,018,843	104,119
Adjustment to Rate Base	87,944,243	19,886,267	1,038,487	448,807	838,426	116,514
Total Pro Forma Rate Base	174,957,346	34,585,163	2,026,761	1,887,448	1,857,269	220,633
Pro Forma Rate of Return	3.528%	4.209%	-0.370%	1.422%	5.863%	2.104%
Increase at Equal Rate of Return	11,755,544	1,934,074	266,902	192,575	53,004	20,020
Percent	21.1%	16.5%	57.6%	53.0%	9.9%	31.9%

Direct Testimony of

Stephen J. Baron

Exhibit SJB-9

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Operating Income and Rate of Return							
Operating Sales Revenues	55,454,439	16,960,743	10,037,000	198,790	2,834,317	11,109,096	1,117,487.61
Adjustments to Sales Revenues	150,375	(55,570)	245,741	3,479	26,634	(1,655)	6,430
Total Sales Revenues	55,604,814	16,905,173	10,282,741	202,269	2,860,951	11,107,441	1,123,918
Other Revenues	2,739,122	763,685	446,224	10,707	102,710	467,463	44,055
Adjustments to Other Revenues	(516,834)	(170,421)	(95,997)	(2,302)	(24,508)	(99,896)	(9,401)
Total Other Revenues	2,222,288	593,264	350,227	8,405	78,202	367,567	34,654
Total Operating Revenues	57,827,102	17,498,437	10,632,968	210,674	2,939,153	11,475,008	1,158,572
Operating Expense							
Cost of Fuel and Purchased Power	22,311,651	5,489,002	3,612,510	80,781	1,274,675	4,745,021	440,270
Adj. to Cost of Fuel and Purchased Pwr	(1,809,945)	(485,102)	(319,815)	(6,881)	(97,488)	(407,237)	(37,997)
Total Cost of Fuel and Purchased Pwr	20,501,706	5,003,900	3,292,695	73,900	1,177,187	4,337,784	402,273
Other O&M Expense	15,814,584	6,324,551	3,264,871	81,444	620,195	2,823,464	269,474
Adjustments to Other O&M	3,453,814	1,102,722	683,864	14,896	164,091	780,928	73,616
Total Other O&M Expense	19,268,398	7,427,273	3,948,735	96,340	784,286	3,604,392	343,090
Total Operation & Maintenance Expense	39,770,104	12,431,173	7,241,430	170,240	1,961,473	7,942,176	745,363
Depreciation Expense	6,901,088	2,369,218	1,370,345	34,893	305,713	1,383,394	130,138

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Residential Rate 10	Total Small General Rate 20	Total Irrigation Rate 25	Total LG Primary Rate 30	Total LG Secondary Rate 30	Total TOD Rate 31
Adjustment to Depreciation Expense	4,608,083	1,421,817	879,230	21,587	225,129	984,165	92,128
Total Depreciation Expense	11,509,171	3,791,035	2,249,575	56,480	530,842	2,367,559	222,266
Taxes Other Than Income Taxes	4,080,304	1,775,685	893,330	31,063	140,888	586,880	55,482
Adjustment to Taxes Other Than Income	617,220	220,346	126,293	3,479	26,630	120,619	11,346
Total Taxes Other Than Income	4,697,524	1,996,031	1,019,623	34,542	167,518	707,499	66,828
Current Income Taxes - Fed. & State	(4,064,987)	(1,876,660)	(996,310)	(48,097)	(113,160)	(747,013)	(40,499)
Adjustment to Current Income Taxes	(13,304,336)	(3,989,658)	(2,443,102)	(55,443)	(658,887)	(3,018,917)	(280,285)
Total Current Income Taxes	(17,369,323)	(5,866,318)	(3,439,412)	(103,540)	(772,047)	(3,765,930)	(320,784)
Deferred Income Taxes	5,966,980	2,118,745	1,222,466	33,936	257,856	1,172,793	110,131
Adjustment to Deferred Income Tax	7,080,843	2,024,220	1,334,492	28,020	362,740	1,659,875	155,491
Total Deferred Income Taxes	13,047,823	4,142,965	2,556,958	61,956	620,596	2,832,668	265,622
Total Operating Expenses	51,655,299	16,494,886	9,628,174	219,678	2,508,382	10,083,972	979,295
Pro Forma Operating Income	6,171,803	1,003,551	1,004,794	(9,004)	430,771	1,391,036	179,277
Rate Base	87,013,108	31,489,542	18,351,437	317,601	3,127,657	16,665,896	1,566,744
Adjustment to Rate Base	87,944,243	25,405,400	16,499,273	443,286	4,689,983	20,048,781	1,874,990
Total Pro Forma Rate Base	174,957,351	56,894,942	34,850,710	760,887	7,817,640	36,714,677	3,441,734
Pro Forma Rate of Return	3.528%	1.764%	2.883%	-1.183%	5.510%	3.789%	5.209%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Operating Income and Rate of Return						
Operating Sales Revenues	55,454,439	11,764,496.50	465,178.22	364,358.96	540,358	62,615.22
Adjustments to Sales Revenues	150,375	(69,664)	(1,869)	(1,015)	(2,287)	149
Total Sales Revenues	55,604,814	11,694,833	463,309	363,344	538,071	62,764
Other Revenues	2,739,122	349,702	18,531	184,846	348,267	2,932
Adjustments to Other Revenues	(516,834)	(98,272)	(4,354)	(4,464)	(6,577)	(642)
Total Other Revenues	2,222,288	251,430	14,177	180,382	341,690	2,290
Total Operating Revenues	57,827,102	11,946,263	477,486	543,726	879,761	65,054
Operating Expense						
Cost of Fuel and Purchased Power	22,311,651	6,155,429	203,242	89,880	191,504	29,337
Adj. to Cost of Fuel and Purchased Pwr	(1,809,945)	(415,233)	(15,563)	(7,076)	(15,072)	(2,481)
Total Cost of Fuel and Purchased Pwr	20,501,706	5,740,196	187,679	82,804	176,432	26,856
Other O&M Expense	15,814,584	1,837,823	123,698	195,907	254,325	18,832
Adjustments to Other O&M	3,453,814	547,216	27,493	20,665	33,526	4,797
Total Other O&M Expense	19,268,398	2,385,039	151,191	216,572	287,851	23,629
Total Operation & Maintenance Expense	39,770,104	8,125,235	338,870	299,376	464,283	50,485
Depreciation Expense	6,901,088	1,017,682	57,740	99,202	124,041	8,722

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Adjusted Embedded Class Cost of Service Study
Using 12 CP Methodology
Twelve Months Ended December 31, 2014

	Total Montana	Total Contract Srvcs. Rate 35	Total Municipal Pumping Rate 48	Total Outdoor Lighting Rate 52	Total SL Rate 41	Total Secondary Rate 32
Adjustment to Depreciation Expense	4,608,083	846,800	39,784	37,488	53,903	6,052
Total Depreciation Expense	11,509,171	1,864,482	97,524	136,690	177,944	14,774
Taxes Other Than Income Taxes	4,080,304	352,772	38,579	99,183	102,414	4,028
Adjustment to Taxes Other Than Income	617,220	84,566	5,359	8,082	9,743	757
Total Taxes Other Than Income	4,697,524	437,338	43,938	107,265	112,157	4,785
Current Income Taxes - Fed. & State	(4,064,987)	(110,616)	(43,011)	(63,133)	(18,667)	(7,821)
Adjustment to Current Income Taxes	(13,304,336)	(2,526,697)	(112,280)	(75,673)	(125,075)	(18,319)
Total Current Income Taxes	(17,369,323)	(2,637,313)	(155,291)	(138,806)	(143,742)	(26,140)
Deferred Income Taxes	5,966,980	817,617	52,115	80,548	93,436	7,337
Adjustment to Deferred Income Tax	7,080,843	1,362,454	58,067	27,541	57,939	10,004
Total Deferred Income Taxes	13,047,823	2,180,071	110,182	108,089	151,375	17,341
Total Operating Expenses	51,655,299	9,969,813	435,223	512,614	762,017	61,245
Pro Forma Operating Income	6,171,803	1,976,450	42,263	31,112	117,744	3,809
Rate Base	87,013,108	12,237,523	753,117	1,418,480	977,032	108,079
Adjustment to Rate Base	87,944,243	16,896,410	752,836	424,318	787,640	121,326
Total Pro Forma Rate Base	174,957,351	29,133,933	1,505,953	1,842,798	1,764,672	229,405
Pro Forma Rate of Return	3.528%	6.784%	2.806%	1.688%	6.672%	1.660%

Direct Testimony of

Stephen J. Baron

Exhibit SJB-10

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-005 RE: Cost of Service
Witness: Cardwell/Aberle

Please explain how the Company uses the results of its embedded cost of service study and its marginal cost of service study to specifically develop the proposed increases for each rate class. How does the Company weight these two studies in this determination (class rate increases)?

Response:

Montana-Dakota relied primarily on the embedded class cost of service study in its development of the proposed increase for each rate class.

Direct Testimony of

Stephen J. Baron

Exhibit SJB-11

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED SEPTEMBER 23, 2015
DOCKET NO. D2015.6.51

PSC-032
Regarding: Transmission Cost Recovery Rider
Witness: Aberle

a. **If MDU has an authorized transmission cost recovery rider (TCRR) in any of its other jurisdictions, provide the approved tariff schedule(s).**

b. **Is there a cap on the costs that could be included in the TCRR, as proposed?**

c. **Would the adoption of the TCRR, as proposed, imply pre-approval of the prudence of costs included in the TCRR? If not, how does MDU propose the Commission vet the prudence or reasonableness of the costs?**

d. **Under a scenario where the Commission approved the TCRR as MDU has proposed and later found costs included in the TCRR imprudent, how would MDU return the overcharges to customers?**

Response:

a. Please see Attachment A for a copy of the Company's North Dakota Transmission Cost Adjustment Rate 59.

b. Montana-Dakota has not proposed a cap on the costs to be recovered through the TCRR.

c. The adoption of the tariff as proposed in this case does not imply pre-approval of the prudence of costs to be recovered under the TCRR. Montana-Dakota envisions that the TCRR would be submitted with costs to be recovered for specific projects or expenses with full support provided and demonstration that the investment and or expenses are not already included in retail rates. The proposed tariff would then be noticed for comment and Commission decision similar to any other tariff change submitted to the Commission.

d. Please see Response No. PSC-032c. If the costs were implemented on an interim basis and if costs were later determined to be not recoverable appropriate refunds would be made. Simple cost true-ups would be handled through the tracker mechanism.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

NDPSC Volume 4
Original Sheet No. 43

TRANSMISSION COST ADJUSTMENT Rate 59

1. **Applicability:**
This rate schedule represents a Transmission Cost Adjustment and specifies the procedure to be utilized to recover the net balance of the capital and operating costs and revenue credits of Montana-Dakota's transmission related expenses and revenues determined to be eligible for recovery in accordance with 49-05-04.3 NDCC. Costs to be recovered under the Transmission Adjustment shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

2. **Transmission Cost Adjustment:**
   a. An adjustment per Kwh will be determined based on the cumulative transmission related costs and revenue credits eligible for recovery and as allocated to the North Dakota jurisdiction as of November 1 of each year and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

   b. The adjustment will be applicable to all retail customers for electric energy sold, except those served under special contract and allocated among the rate classes based on the transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case.

   c. The adjustment per Kwh will be revised annually to reflect the current level of costs to be recovered.

Date Filed:	October 21, 2011	**Effective Date:**	Service rendered on and after June 1, 2012
Issued By:	Tamie A. Aberle Regulatory Affairs Manager	**Case No.:**	PU-11-672

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

TRANSMISSION COST ADJUSTMENT Rate 59

d. The true-up will reflect any over or under collection of revenue under the Transmission Adjustment from the preceding twelve month period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Time and Manner of Filing:**
Montana-Dakota shall file the Transmission Adjustment at least 30 days prior to the proposed effective date. The filing by Montana-Dakota shall be made by means of a revised Transmission Adjustment tariff sheet identifying the amounts of the adjustment, the derivation of the adjustment and the resulting Transmission Adjustment rate.

4. **Transmission Cost Adjustment Rate by class:**

Residential & Small General	0.125¢
Large General	0.104¢
Lighting	0.079¢

Direct Testimony of

Stephen J. Baron

Exhibit SJB-12

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SEVENTH DATA REQUEST
DATED OCTOBER 21, 2015
DOCKET NO. D2015.6.51

LCG-075 RE: Environmental Cost Recovery Rider

Please refer to Exhibit TAA-3. Please explain why the charge for the proposed Environmental Cost Recovery Rider - Rate 98 is designed a kWh charge for demand-billed customers? Wouldn't a demand charge be more appropriate given the nature of the costs that MDU proposes to recover through Rate 98? If MDU disagrees, please explain the basis for the disagreement.

Response:

Montana-Dakota proposed to simply collect costs on a per Kwh basis but agree that cost recovery as a demand charge may be more appropriate for demand metered customers.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SEVENTH DATA REQUEST
DATED OCTOBER 21, 2015
DOCKET NO. D2015.6.51

LCG-076 RE: Transmission Cost Recovery Rider

Please refer to Exhibit TAA-4. Please explain why the charge for the proposed Transmission Cost Recovery Rider - Rate 99 is designed a kWh charge for demand-billed customers? Wouldn't a demand charge be more appropriate given the nature of the costs that MDU proposes to recover through Rate 99? If MDU disagrees, please explain the basis for the disagreement.

Response:

Montana-Dakota proposed to simply collect costs on a per Kwh basis but agree that cost recovery as a demand charge may be more appropriate for demand metered customers.

Direct Testimony of

Stephen J. Baron

Exhibit SJB-13

MISCELLANEOUS TAXES AND FEES

Consumer Counsel and Public Service Fees **Contractor's Gross Receipts Tax**

Electrical Energy and Wholesale Transaction Taxes **Lodging Facility Use and Sales Taxes**

Nursing Facility Tax and Utilization Fees **Rental Vehicle Tax**

Telecommunications Taxes and Fees

CONSUMER COUNSEL AND PUBLIC SERVICE FEES

Consumer Counsel Fee:

All companies providing services which are regulated by the Public Service Commission are subject to a quarterly fee on gross operating revenue generated by all regulated activities within Montana. This fee is set annually and applies to the fiscal year period October 1 through September 30. All revenues are deposited to a state special revenue fund and used to cover appropriations to the office of consumer counsel. (69-1-201, MCA through 69-1-230, MCA: 42.31.902, ARM)

Public Service Regulation Fee:

All companies providing services, which are regulated by the Public Service Commission, are subject to a quarterly tax on gross revenues excluding revenues from sales to other regulated companies for resale. The tax rate is set annually for the succeeding fiscal year. All collections are deposited in a state special revenue fund. (69-1-402, MCA)