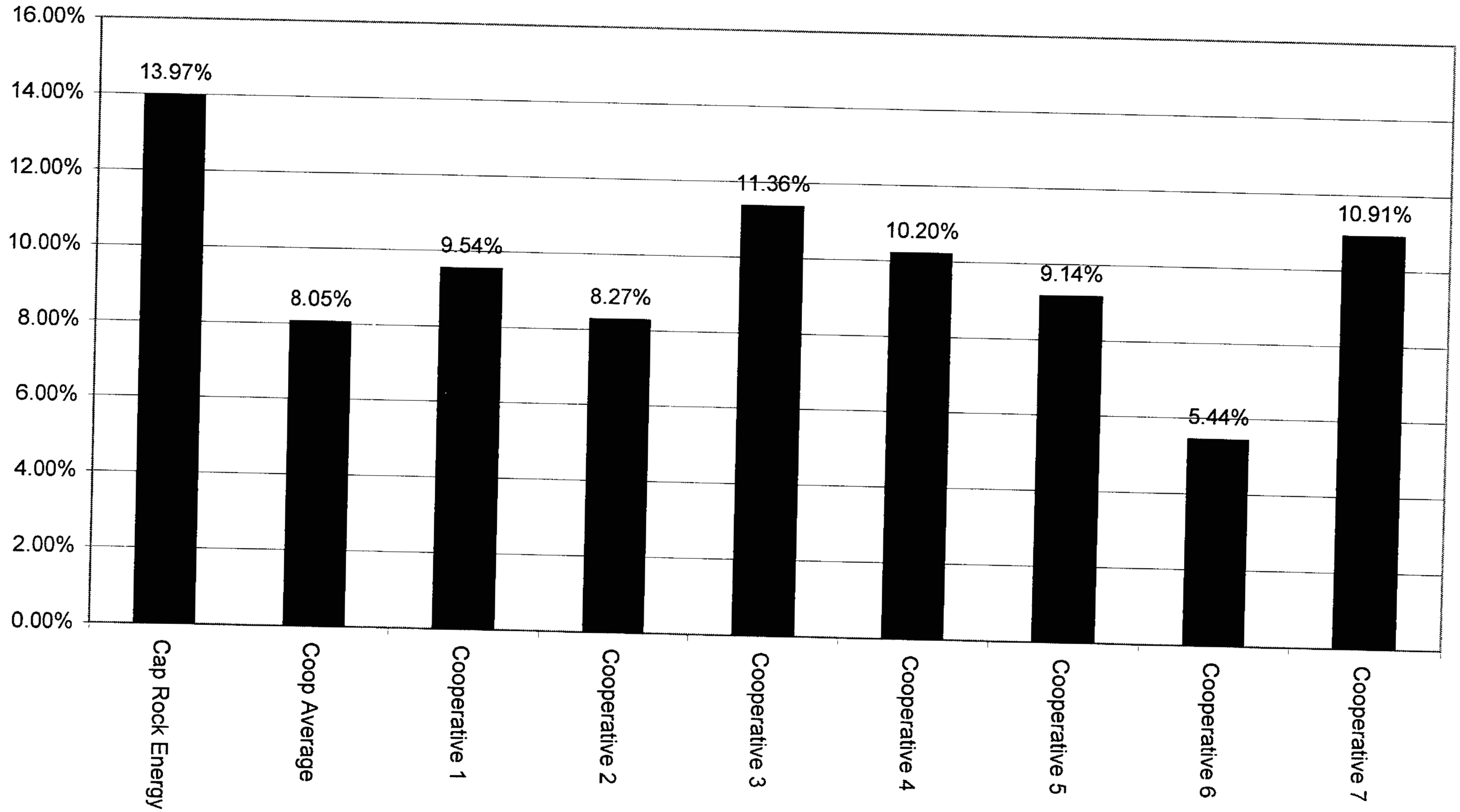
Comparison of Losses
Cap Rock vs. Comparable Electric Cooperatives



Comparison of Significant Cost Allocation Changes

Allocated Item	2002 Study	Cap Rock Proposal	Impact on Costs Allocated to: Cotton Gins	Irrigation
Transmission Plant	Allocated entirely on loss adjusted kWh by class	Allocated entirely on annual NCP demands by customer class	**Increase**	**Increase**
Distribution Lines - Demand	Allocated on contribution to Annual CP	Allocated on density weighted NCP demands by customer class	**Increase**	**Increase**
Distribution Lines - Base	Allocated on average demand (kWh)	None	**Increase**	**Increase**
Transformers	Included in allocation of Distribution Secondary and allocated on CP demands and kWh	Weighted customers and NCP Demands weighted by replacement costs	**Increase**	Unknown
Meters	Customer weighted (basis unknown)	Customer weighted (based on estimated replacement costs)	Decrease	Decrease
Services	Included in allocation of Distribution Secondary and allocated on CP demands and kWh	Customer weighted based upon average line extension	Unknown	**Increase**
General Plant	Allocated on T&D Plant	Allocated on T&D Plant	**Increase**	**Increase**
Transmission O&M	Included in Distribution O&M	CP Demand	Unknown	Unknown
Distribution O&M	Allocated consistent with distribution plant	Allocated consistent with distribution plant	**Increase**	**Increase**
Meter Reading Expense	Weighted customers consistent with meters investment	Weighted customers consistent with meters investment	Decrease	Decrease
Other Customer Acctg. Expenses	Allocated by account, predominantly on total number of customers	Allocated on Weighted Meter Reading	**Increase**	**Increase**
Customer Service Expenses	Total Customers	Total Customers	None	None
Customer Sales Expenses	Total Customers	Total Customers	None	None
A&G Expenses Less Property Insurance	O&M excluding Purchased Power.	Transmission & Distribution Plant	**Increase**	**Increase**

Calculation of
Proposed Demand Allocators for
Substations and Distribution Lines

Substations - 4 Coincident Peak Demands

		System Coincident Peak Demands					
Line	**RATE CLASS**	Jan-03	Feb-03	Jul-03	Aug-03	Average	%
1	General Service	61,685	67,341	55,608	58,558	60,798	46.62%
2	General Service-City Limits	1,919	1,859	1,931	2,115	1,956	1.50%
3	Lighting	164	164	-	-	82	0.06%
4	Irrigation	1,586	3,269	12,175	15,516	8,137	6.24%
5	Commercial	33,510	34,511	34,472	35,619	34,528	26.47%
6	Large Power - Primary	10,252	16,509	15,748	19,478	15,497	11.88%
7	Large Power - Secondary	5,041	8,140	8,023	9,100	7,576	5.81%
8	Cotton Gin	7,388	-	-	-	1,847	1.42%
9	**Total**	121,545	131,793	127,957	140,386	130,420	100.00%

Overhead Distribution - 4 Non-Coincident Peaks

		Monthly Non-Coincident Peak Demands					
Line	**RATE CLASS**	Jan-03	Feb-03	Jul-03	Aug-03	Average	%
1	General Service	67,257	72,001	63,886	64,353	66,874	45.02%
2	General Service-City Limits	2,092	1,988	2,219	2,325	2,156	1.45%
3	Lighting	85	85	85	85	85	0.06%
4	Irrigation	1,869	3,789	13,605	22,730	10,498	7.07%
5	Commercial	41,126	41,192	40,366	38,261	40,236	27.09%
6	Large Power - Primary	14,975	17,895	18,860	19,260	17,748	11.95%
7	Large Power - Secondary	7,362	8,824	9,609	8,998	8,698	5.86%
8	Cotton Gin	7,388	1,597	-	-	2,246	1.51%
9	**Total**	142,154	147,371	148,630	156,012	148,542	100.00%

Underground Distribution - 4 Non-Coincident Peaks

		Monthly Non-Coincident Peak Demands					
Line	**RATE CLASS**	Jan-03	Feb-03	Jul-03	Aug-03	Average	%
1	General Service	67,257	72,001	63,886	64,353	66,874	56.65%
2	General Service-City Limits	2,092	1,988	2,219	2,325	2,156	1.83%
3	Lighting	85	85	85	85	85	0.07%
4	Irrigation	-	-	-	-	-	0.00%
5	Commercial	41,126	41,192	40,366	38,261	40,236	34.08%
6	Large Power - Primary	-	-	-	-	-	0.00%
7	Large Power - Secondary	7,362	8,824	9,609	8,998	8,698	7.37%
8	Cotton Gin	-	-	-	-	-	0.00%
9	**Total**	117,922	124,090	116,165	114,022	118,050	100.00%

Exhibit No.___(JSG-1)

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-399-_____

PREPARED DIRECT TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7508 Wisconsin Avenue, Suite 300 Bethesda, MD 20814.

Q2. Would you please describe your educational and professional background?

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also received a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were in finance and economics.

From 1977 to 1980, I worked for H. Zinder & Associates as a research assistant and later as supervisor of regulatory research. In 1980 and 1981, I was employed by Olson and Company where my primary duties were to assist in the preparation of cost of capital studies for presentation in regulatory proceedings.

From 1982 to 1986 I undertook graduate studies in economics and finance at Indiana University where I also taught courses in public utilities, transportation, and physical distribution. During this time I also was employed as an independent consultant on a number of projects involving public utility regulation, rate design, and cost of capital. From 1983-1986 I was coordinator for the Edison Electric Institute Electric Rate Fundamentals course. In 1986 I accepted an appointment as

III. CLASS COST OF SERVICE STUDY

Q49. Were Statements G and M prepared by you or under your direction?

A. Yes.

Q50. Are you also sponsoring the filed tariff and rate design changes?

A. Yes. I have had primary responsibility for working with Montana-Dakota employees in designing the rate and tariff changes proposed in this filing. If there are questions concerning the changes in electrical equipment requirements, or other revisions to tariff Rate 110, these will be addressed by an appropriate Montana-Dakota witness.

A. Rate Design Objectives and Principles

Q51. What are the primary objectives of a rate (price) structure for the services that are offered by a regulated company?

A. As a general matter, the following eight criteria of Professor James C. Bonbright have remained viable and resilient over the four decades since their first publication (*Principles of Public Utility Rates*, 1961, page 291):

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretations.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.

5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amount of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off peak electricity,….)

Q52. Are these foregoing general criteria for rate structures all consistent with one another?

A. No, they need not be. By illustration, a given rate structure that embodies the ultimate in rate *stability* could soon become unacceptable with respect to other criteria, e.g., achieving a fair rate of return, or relative fairness among customer classes. Thus, there can be tensions and conflict among these rate criteria, based on the specific facts and circumstances of any company.

Q53. Does each of these foregoing rate criteria carry equal importance and weight?

A. No. I agree with Professor Bonbright's assessment (page 292) that the rate criteria designated as items (3), (6) and (8) above are the three primary ones. Many rate design and rate structure disputes revolve around the tensions that can arise between items (6) and (8), i.e., the potential conflict between standards of "fairness" and "efficiency" as among the affected customer classes. From these potential conflicts arise many current rate debates, such as the proper nature and form(s) of marginal-cost pricing. However, the importance of the "fair return" criteria for a rate structure is hard to overstate. A set of rates that putatively meet all of the other rate criteria, but that fails to generate an acceptable return on and return of capital, can jeopardize the basic viability of the operation and its ability to render service. Consequently, rates that comport with fair return standards are a predicate for a viable privately-owned operating entity that can seek to satisfy all of these other applicable rate criteria.

Q54. How have you employed these principles and objectives of rate design in developing the proposed rates for Montana-Dakota's electric services?

A. Most importantly, the rates are set at a level that is designed to recover the overall cost of service without major disruptions in load or overall cost recovery.

Next in importance is an attempt to reflect the costs of providing services to individual customers. Through the cost allocation process, the relative costs of providing service to each class of customers are identified. However, in order to mitigate the impacts of the indicated rate changes for some of the classes of customers, I have limited the percentage rate change for each major class of service to two times the overall average rate increase required.

The rate design attempts to promote fairness and efficiency in several ways. First, by increasing the degree to which the costs recovered in each rate component (i.e., Base Charge, Energy Charge and Demand Charge) correspond to the manner in which costs are incurred by Montana-Dakota. A fair and efficient rate design recognizes that most costs, especially rate base, depreciation and return on rate base, are fixed costs and that recovery of these fixed costs should

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