STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation
Electric Rate Increase
Application

Case No. PU-08-862

AFFIDAVIT OF SERVICE CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Janet Marquart deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **9th** day of **April, 2009,** she deposited in the United States Mail, Bismarck, North Dakota, **nine** envelopes with certified postage, return receipt requested, fully prepaid, all securely sealed and each containing a photocopy of:

DIRECT TESTIMONY OF CHARLES W. KING
DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.

The envelopes were respectively addressed as follows:

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Associate General Counsel
Otter Tail Corporation
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Mr. Thomas R. Brause
Vice President Administration
Otter Tail Corporation
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Ms. Kavita Maini
KM Energy Consulting, LLC
961 N. Lost Woods Road
Oconomowoc WI 53066
Cert. No. 7008 1830 0004 1758 7140

Each post office address shown is the respective addressee's last reasonably ascertainable post office address.

Janet Marquart

Subscribed and sworn to before me
this **9th** day of **April, 2009**.

SEAL

JOHN G. HAMRE
Notary Public
State of North Dakota
My Commission Expires July 4, 2014

Notary Public

Public Service Commission
State of North Dakota

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April 6, 2009

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: Otter Tail Corporation
Electric Rate Increase Application
Case No. PU-08-862

Dear Mr. Nitschke:

Enclosed for filing in the above case are the original and seven copies of the direct testimonies of staff witnesses Charles King and Michael Majoros. The testimonies support a base rate increase of $4.9 million and a reduction in fuel cost recoveries of $3.6 million per year.

Sincerely,

Mike Diller
Director of Economic Regulation
North Dakota Public Service Commission

Enclosures

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of the Otter Tail Power Company,
For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-08-862

DIRECT TESTIMONY OF CHARLES W. KING

April 6, 2008

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TESTIMONY OF CHARLES W. KING

INTRODUCTION / SUMMARY

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Bedell, Inc. (Snavely King). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King, formerly Snavely, King, & Associates, Inc., was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs, and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers, and cost analysts. Most of its work involves the development, preparation, and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 39-year history, members of the firm have participated in over a thousand proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Exhibit_____(CWK-1) is a summary of my qualifications and experience.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. Exhibit _____(CWK-2) is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission.

Q. What is the objective of your testimony?

A. The objective of my testimony is to present the position of the Advocacy Staff with respect to the allocation of costs and revenues among the various classes of customers of the Otter Tail Power Company ("OTP" or "the Company") and with respect to the rate design proposals that the Company has made in this case.

Q. Please summarize your recommendations?

A. I generally agree with the approach that OTP has take to designing its rates, which is to allocate revenue among classes based on embedded costs, but to use marginal costs to structure the rate elements within rate schedules.

I have made several modifications to the class cost of service study proposed by the Company to reflect better the causation of costs for the distribution system and sales expense. Based on my revised cost of service study, I recommend that the residential class receive the average percentage rate increase, that the Company's proposed increases to the revenue-deficient classes be accepted, and that the excess revenue derived from those increases be applied to reduce the rates for the two revenue-sufficient classes in proportion to their excess earnings over the

Company average. The revenue sufficient classes are the large and small general service classes.

I recommend that the Company's rate design proposals be accepted subject to the limitation that no customer receive a rate increase greater than 50 percent over the average increase for the class, and for the classes not being significantly increased, no customer receive an increase greater than 10 percent. The Company has revised several of its rate designs to conform to these limitations.

Finally, I recommend that facilities-based wholesale margins be credited to the Energy Cost Adjustment and that the Company's proposal to include the full cost of the wholesale trading department in the revenue requirement in return for a 15 percent sharing of non-asset based wholesale margins be denied.

RATEMAKING APPROACH

Q. How has OTP designed the rates it proposes to charge the respective classes of customers?

A. OTP distributes its revenue requirement among classes based on an allocation of embedded costs, reconciled to the overall revenue requirement. The embedded Class Cost of Service ("CCOS") study is sponsored by OTP witness Peter Beithon, as is the Company's recommended distribution of revenue generation among the classes. Once Mr. Beithon has decided how much revenue each class should generate, witness David Prazak then structures the rate elements within each rate

schedule based on a marginal cost study performed by National Economic Research Associates and sponsored by witness Hethie Parmesano.

Q. Should class revenue generation be based on an embedded CCOS study?

A. Yes. When the objective is to distribute the Company's overall revenue requirement among customer classes, necessarily the allocation must conform to the revenue requirement calculation. The revenue requirement is based on embedded costs, that is, the record of investments and expenses during the test year (in this case calendar 2007).

The CCOS study is not a prescription, however, and some judgment is required in translating class cost allocations into a distribution of revenue generation. First, the principle of rate continuity requires that abrupt rate changes be avoided. This issue is particularly relevant in this case, where the Company is restructuring its rates for the first time in 25 years. Second, the allocation of costs among customer classes is not always straightforward. As the record of this case will demonstrate, there are legitimate differences of opinion as to the appropriate assignment of costs that are shared among customer classes.

Q. Should the rate structures within customer classes be based on marginal costs, as OTP proposes?

A. In general, yes. In her testimony, Dr. Parmesano presents the conventional argument in favor of using marginal costs to design rates – that they will

lead to economically efficient decisions by ratepayers seeking to minimize their energy costs.

The strength of this argument, however, is largely a function of the price elasticity of demand, that is, the extent to which customers adjust their energy consumption in response to price differences. For electricity, price elasticity varies by customer class and by rate element. For the most part, residential demand is price inelastic. Except when there are very large changes in rates, residential customers consume electricity according to their life styles, not the per-kWh price of electricity. Commercial and industrial customers are much more price-sensitive. Large industrial customers in particular will expend considerable effort to reduce electricity costs by only a few percentage points.

Within rate schedules, it is reasonable to assume that flat monthly charges are totally price-inelastic. No customer is going to abandon electric service because the customer charge is too high or subscribe to electric service because it is low. What price elasticity exists pertains to the energy and demand charges. Any customer response will be made in light of these charges.

This observation suggests that deviations from marginal costs should be concentrated in the flat monthly charges. All of OTP's rates are below marginal costs, so that they are arguably inefficient. To the extent that this inefficiency is unavoidable, it should be reflected more in the level of monthly charges and less in energy and demand charges. I will apply

this principle in my recommendations concerning the reductions in class revenue recovery later in this testimony.

Marginal costs are most useful in designing the relative levels of energy and demand charges and of time and seasonally differentiated rates. This is the principal use that OTP has made of its marginal cost study. It has used marginal costs to determine the relative levels of demand and energy rates and of rates during peak and off-peak hours and seasons.

CLASS COST OF SERVICE STUDY

Q. Please describe OTP's Class Cost of Service Study.

A. OTP's 2006 Class Cost of Service (CCOS) study is presented in Schedule 10 to Exhibit ___(PJB-1) attached to the testimony of Company witness Peter Beithon. In response to a data request, the Company has submitted a 2007 CCOS Study reflecting its going forward rate base and expense adjustments. This study allocates all of the costs for calendar year 2007 among 10 customer classes. It then computes the rate of return for each class at present rates. To the extent that any class earns less than the jurisdictional average rate of return, it is deemed revenue-deficient. If it earns more than the overall return, it is revenue-sufficient. The Company's CCOS study suggests that the two general service classes are revenue sufficient, and that all other classes are revenue deficient. The irrigation, controlled service water heating and controlled service interruptible classes are particularly revenue deficient.

Q. Do you agree with the Company's CCOS study?

A. No. OTP's CCOS study is deficient in three respects. First, it allocates a portion of the primary distribution system on the basis of the number of customers on the system. This allocation is inconsistent with the marginal cost study sponsored by witness Hethie Parmeso. Dr. Parmesano finds that the cost driver for the primary distribution system is coincident peak demand.[1] She makes no reference to the number of customers.

Second, the Company's CCOS study allocates a portion of the secondary distribution system on the basis of the number of customers. It is appropriate to allocate Account 369, Customer Services, on the basis of the number of customers, but the Company's allocator does not recognize that the cost of services to large customers is considerably greater than to small customers, particularly residential customers.

Finally, the cost of the Sales Department is allocated based on the number of customer meters. There is no justification for this allocation, particularly as the Sales Department is principally focused on attracting industrial and commercial customers, not residential customers, to OTP's service territory.

Q. What adjustments have you made to OTP's CCOS Study?

A. First, I have allocated all of the primary distribution system on the basis of peak demand. Second, I have weighted the customer allocation of the secondary distribution system according to the respective customer service

[1] Marginal Cost Study, Response to ND PSC IR 01-039, Attachment 1, page 19.

costs as reported in Dr. Parmesano's marginal cost study.[2] Third, I have allocated the Sales Department expense based on class MWh sales.

Q. What are the results of your adjusted CCOS Study?

A. The results of the CCOS Study with the foregoing adjustments are presented in Schedule 2 of Exhibit____(CWK-3). The schedule shows the revenue adjustments that would be required in order for all customer classes to generate the 2007 system average rate of return . A summary of these rates of return and revenue adjustments is as follows:

	Current Revenues	Earned Return	Increase (Decrease) Revenue	Percent
Residential	36,574,921	6.24%	641,106	1.75%
General Service	34,012,150	11.66%	(3,935,201)	-11.57%
Large General Service	36,231,788	9.90%	(2,430,542)	-6.71%
Farms	1,601,767	2.68%	222,250	13.88%
Irrigation	45,963	-4.18%	35,904	78.11%
Lighting	2,095,668	-1.09%	767,039	36.60%
Other Public Authorities	967,569	-0.08%	220,941	22.83%
Controlled Service Water Heating	1,185,332	-3.26%	652,305	55.03%
Controlled Service Interruptible	4,744,402	-10.07%	3,551,197	74.85%
Controlled Service Deferred	849,617	-1.74%	275,001	5.80%
	$118,309,177	6.91%	0	0.00%

CLASS REVENUE CHANGES

Q. How should any rate increase be distributed among the classes of customers?

A. The CCOS Study indicates that the residential class is earning slightly below the system average, that the two general service classes are earning more than the average, and that the remaining classes are

[2] Schedule 1 of Exhibit____(CWK-3) is the worksheet on which I developed the alternative allocators.

earning substantially less than the system average. The deficiencies of these latter classes are so great that they cannot be resolved in one rate case. To eliminate the apparent disparities in earned returns would violate the principle of rate continuity.

I therefore recommend that the residential class be given the system average increase. In its initial filing, the Company has recommended a set of increases for the revenue-deficient classes that reduce, but do not eliminate the earnings deficiencies that they display. I recommend that these increases be accepted. The added revenue from these class rate increases should then be applied to reduce the rates to the two general service classes.

These revenue changes are fairly dramatic. To some extent they are the consequence of the absence of any comprehensive rate case for OTP since 1983. The rate levels and rate structures that seemed appropriate 25 years ago no longer apply. For this reason, significant rate adjustments now need to be made. In particular, it is appropriate to reduce the revenue-to-cost imbalances between rate schedules that effectively compete with each other. For example, the all controlled service customers have the option of subscribing to the general service rate schedules. If their rates are artificially low relative to the general service rates, then customers may make uneconomic choices in selecting among service options.

Q. Have you calculated the rate changes that you recommend under a hypothetical rate increase?

A Yes. For purposes of illustration I have assumed an overall 2 percent rate increase. In Schedule 3 of Exhibit_____(CWK-3) I have calculated the class rate increases that would be indicated using the guidelines I have described. A summary of the rate changes is as follows:

	Current Revenues	Increase (Decrease) Revenue	Percent
Residential	$ 36,574,921	$ 731,498	2.00%
General Service	34,012,150	(631,059)	-1.86%
Large General Service	36,231,788	(390,893)	-1.08%
Farms	1,601,767	120,133	7.50%
Irrigation	45,963	4,596	10.00%
Lighting	2,095,668	523,917	25.00%
Other Public Authorities	967,569	135,460	14.00%
Controlled Servce Water Heating	1,185,332	118,533	10.00%
Controlled Servce Interruptible	4,744,402	1,660,541	35.00%
Controlled Service Deferred	849,617	93,458	11.00%
	$118,309,177	$ 2,366,184	2.00%

RATE CHANGES WITHIN CLASSES

Q. Are there issues with respect to rate changes within the respective classes?

A. Yes. OTP is proposing to modify severely the structure of its rates within classes. First, it is changing the application of many of its rate schedules, eliminating some and adding others. Second, it is eliminating all declining block rates. Third, it is proposing to apply the Energy Adjustment Rider ("EAR")[3] to all rate schedules other than the fire sirens and the real time and marginal energy price schedules. Finally, it is structuring the

[3]Company witness Prazak refers to the "FCA," which stands for Fuel Cost Adjustment, but its actual name on Sheet 13.01 of the tariff is the "Energy Adjustment Rider."

individual energy and demand charges to reflect marginal costs, which requires the introduction of seasonally differentiated rates throughout the tariff.

These rate structure modifications can result in fairly dramatic changes in individual customer's bills, even when the overall change in the class revenue is relatively modest. These various effects can be seen in the bar charts in Mr. Prazak's testimony showing the varying impacts on the duo-deciles of bill size for each rate schedule. For this reason, it is appropriate to place some limits on the extent to which OTP's rate structure changes impose unreasonable increases in customer bills.

Q. Have you proposed such limitations to the Company?

A Yes. I have proposed limiting any one customer's rate increase to 50 percent over the class increase or, for those classes receiving less than a 6.7 percent increase, 10 percent on an annualized basis. Exceptions would be customers with average monthly bills of less than $10 and customers who are able to switch to other rate schedules that would result in increases below the cap limits.

Q. Has the Company responded to this proposal?

A. Yes. Exhibit_____(CWK-4) is my request and the Company's response, inclusive of attachments. In this response, the Company has restructured the Residential, Residential Demand Controlled and Farm Service rate schedules to conform to the rate increase limitations that I have

recommended. It has listed a number of reasons why these limitations should not be applied to the other rate increases.

Q. Do you recommend that the Company's modifications be adopted?

A. OTP's response assumes the adoption of all of the Company's rate increase proposals including the 7.5 percent residential rate increase, and I have recommended that the residential increase be capped at the system average, 5.14 percent in the Company's filing. If the final rate increase is substantially below the Company-proposed 7.5 percent, then the modifications to the residential rate schedules may not necessary. In any case, the adjustments to the Farm Service rate schedule should be adopted.

I am not persuaded by the Company's disclaimers with respect to the other rate schedules. In particular, they relate to the duo-decile rate analyses that combine a number of customer bills into groups. Individual customers may still experience rate increases that exceed the limits I have recommended and the Company appears to have accepted. For this reason, I recommend that the Company notify each customer subject to a rate increase that there is a cap on the increase. If the customer's annual bill exceeds that cap, the Company should refund the excess. The caps would expire at the end of the second year of the effectiveness of the new rates.

Q. If the Commission approves rate increases less than the Company has requested, how should the Company's proposed rates be scaled back?

A. The Company has sought to reflect marginal costs in its seasonal rates for the residential class, and I recommend that these rates be retained. As discussed earlier in this testimony, the reduction from the Company's proposal should come out of the flat monthly charge. The Company proposes a separate customer charge of $3.00 plus a "facilities charge" of $5.00. I see no reason for these separate charges. The same is true for the proposed $9.38 customer charge and $9.00 facilities charge for residential demand control service. They should be combined and reduced from their proposed levels to match the revenue requirement for this class. This modification would reduce the very high increases otherwise imposed on customers with minimal usage.

My recommendation for the general service classes parallels that for the residential class. I recommend that the small general service customer and facilities charges be combined and reduced no lower than the current $7.90 level currently applicable to the zone 9 customers under this rate. Similarly, the $12 monthly charge for the large general service customers should be reduced to no lower than $7.95 rate currently applied to zone 9 customers. These modifications would reduce the very large percentage increases to customers at the low-usage end of these rate schedules.

Q. Are there any other rate structure recommendations you would like to make?

A. Yes. The energy rates proposed by the Company incorporate a fuel and purchased power cost of 3.0945¢ per kilowatt-hour. The Energy Adjustment Rider passes through any variations from this value on a month-to-month basis. It might be more straightforward to express all fuel and purchased power costs in a separate energy charge. In this manner, customers would be able to identify those costs they are paying that are pass-throughs from third-party providers from those that cover Company costs. This has become standard practice in much of the gas utility industry.

Additionally, there is a timing mismatch between the cost of energy and the energy charges. The EAR is based on the average cost of fuel and purchased power during the most recent four months. Given that it takes at least a month to record energy costs, that means that there is a average lag of three to four months in the application of the EAR. For example, the EAR applied in July when energy costs are high will likely reflect the actual cost of energy during the months February through March, when energy costs are lower. Then, the October EAR will reflect the high costs of fuel and purchased power during the summer months, even though October energy costs are likely to be low.

This mismatch was evident during the winter of 2007- 2008. In the autumn of 2007, the Big Stone base load plant was out of commission.

During those low-load months, the EAR was only 0.26 cents per kWh. Big Stone came back on line in December. Because of the lagging nature of the EAR, the effect of the high cost of replacement power during the outage was not felt until after the plant was back in service. As a result, the EAR jumped to 1.53 cents in January, and then spiked to 3.5 cents in February, just when space heating customers most needed electricity. It remained at approximately that level through April, declining only during the spring months of May and June. By July and August, peak-load months, the EAR was less than 0.8 cents per kWh.[4]

The Company witnesses stress the importance of "price signals" in proposing the use of marginal costs to develop seasonal rates. If price signals are important, then it is relevant that the EAR during the summer should reflect summer fuel and purchase power costs, and the EAR during the winter should reflect winter costs.

Based on the foregoing, I recommend that the Company explore the idea of an all-in fuel and purchased power energy charge that is calibrated to the season in which it applies. This will require some degree of forecasting prices and fuel mix, but such forecasting should be feasible in competitive fuel and purchased power markets where forward purchases are made. I request that the Company submit its comments on this proposal in its rebuttal testimony in this case.

WHOLESALE MARGINS

Q. What are "wholesale margins?"

[4] Attachment 1 to ND PSC IR 01-064.

A. Wholesale margins are the difference between the cost of power sold to wholesale customers – other utilities or power marketers -- and the revenue that the Company receives for that power. There are two types of wholesale margins, "asset-based" margins that result from the sale of power generated by OTP's own production plants, and "non-asset-based" margins that result from the resale of power or capacity that the Company acquires from other generators in the competitive power markets.

Q. How are wholesale margins currently treated?

A. Currently, asset-based margins are treated as a offset to the Company's base-rate revenue requirement. Non-asset-based margins are treated "below the line" and are excluded from the revenue requirement calculation. A portion of the wholesale sales department's expenses are also excluded based on the relative mix of asset-based and non-asset-based power.

Q. What are the Company's proposals regarding the treatment of wholesale margins?

A. OTP proposes to continue to include an allowance for asset-based margins as an adjustment to base rate revenue requirements. It is proposing that 15 percent of non-asset-based wholesale margins be credited to the EAR. In return, all of the wholesale sales department's expenses would be incorporated into the base rate revenue requirement.

Q. What is your response to these proposals.

A. Asset-based wholesale margins vary from year to year depending upon the market for power in the MISO transmission area. Given this variability, it is not appropriate to fix a level of wholesale margin into the revenue requirement calculation that will apply to base rates in effect for a number years. Additionally, there is a matter of symmetry. The EAR includes wholesale power purchases. It should include wholesale power sales as well. For these reasons, I recommend that asset-based margins be treated as offsets to the EAR.

It is clear from page 27 of Mr. Beithon's testimony that the Company's proposed sharing mechanism for non-asset-based margins is a losing proposition from the ratepayers' standpoint. Ratepayers' 15 percent share of these margins in 2007 would have been $293,667. In return, they would have been asked to absorb an additional $674,590 in wholesale trading department expenses, for a net loss of $380,923.

Presumably, this infirmity could be resolved by increasing the sharing percentage. But even then, the incorporation of non-asset margins into ratepayer's bills is a poor idea. These margins have nothing to do with the generation and distribution of electric power to OTP's North Dakota ratepayers. They are conducted totally outside of regulated operations, and they expose OTP and its customers to increased risk from which there is no regulatory protection.[5] I recommend that non-asset-based margins and the associated wholesale transaction department

[5] It should be noted that in September of 2008 Constellation Energy was forced to seek a merger partner to cover the collateral obligations associated with its energy trading activities.

expenses continue to be treated below the line. Indeed, it would be better for ratepayers if non-asset-based trading should be spun off into an unregulated subsidiary that is "ring-fenced" from the Company's regulated operations.

Q. Does this complete your testimony?

A. Yes. It does.

Charles W. King

Exhibit____(CWK-1)

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. and Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, costs earnings and depreciation.

Mr. King has testified in electric, gas and water utility cases on virtually every aspect of regulation, including cost of capital, revenue requirements, depreciation, cost allocation and rate design. Mr. King is one of the nation's leading authorities on utility depreciation practices, having testified on this subject in several dozen cases before state regulatory bodies.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations. Mr. King directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

Exhibit_____(CWK-2)

Appearances of Charles W. King before Regulatory Agencies

CHARLES W. KING
Snavely King Majoros O'Connor & Lee, Inc.
1220 L Street, N.W., Suite 410
Washington, D.C. 20005
(202) 371-1111

Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AK	Exxon USA	P-89-1,2	Trans Alaska Pipeline System	October 18, 1990
AZ	Arizona Corporation Commission Arizona Retailers Association	U-1345-I U-1345-II	Arizona Public Service Co. Arizona Public Service Co.	December 16, 1980 January 15, 1981
CA	California Retailers Association California Retailers Association California Retailers Association California Retailers & California Manufacturers California Retailers Association	57666 57602 59351 59351 61138	Pacific Gas & Electric Co. Southern California Edison Pacific Gas & Electric Co. Southern California Edison Southern California Edison	March 6, 1978 April 25, 1978 June 12, 1981 May 20, 1982 May 28, 1982
CO	U. S. Department of Defense J.C. Penney Company U.S. Department of Defense U. S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense	I&S 1100 5693 I&S 1339 I&S 1540 C. Council C. Council C. Council C. Council	Colorado Springs (Elec) All Electric Utilities Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Gas) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec) Colorado Springs DPU (Elec)	June 14, 1977 March 8, 1978 October 18, 1979 February 9, 1982 September 30, 1984 June 6, 1985 May 19, 1986 June 30, 1987
CT	Retailers Merchants Association Division of Consumer Counsel Public Utilities Control Auto Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Division of Consumer Counsel Coalition of Hotels, Alloys & Retailers Coalition of Hotels, Alloys & Retailers	72-0204 76-0604,5 78-0303 80-0403,4 81-0413 81-0602,4 82-0701 85-10-22 87-07-01	Various Electric Utilities CL&P and HELCO Bridgeport Hydraulic Co. CL&P and HELCO United Illuminating Company CL&P and HELCO CL&P CL&P CL&P	July 22, 1976 November 10, 1977 (none) August 11, 1980 July 20, 1981 October 5, 1981 September 28, 1982 (none) April 25, 1988

State	Electric, Gas, Water Utility Cases			
	Client	Case		Date of Cross-Examination
		Case Number	Utility	
DC	D.C. People's Counsel	685	Potomac Electric Power Company	March 6, 1978
	D.C. People's Counsel	715	Potomac Electric Power Company	(none)
	D.C. People's Counsel	725	Potomac Electric Power Company	April 4, 1980
	D.C. People's Counsel	737	Potomac Electric Power Company	January 1, 1981
	Washington Metro Area Transit Authority	748	Potomac Electric Power Company	June 26, 1981
	Washington Metro Area Transit Authority	758	Potomac Electric Power Company	December 15, 1981
	D.C. People's Counsel	785	Potomac Electric Power Company	September 21, 1982
	Washington Metro Area Transit Authority	759	Potomac Electric Power Company	March 29, 1984
	D.C. People's Counsel	685 Remand	Potomac Electric Power Company	June 10, 1985
	D.C. People's Counsel	905	Potomac Electric Power Company	August 20, 1991
	D.C. People's Counsel	912	Potomac Electric Power Company	May 7, 1992
	D.C. People's Counsel	834, III	Potomac Electric Power Company	May 22, 1992
	D.C. People's Counsel	917	Potomac Electric Power Company	September 24, 1992
	D.C. People's Counsel	922	Washington Gas Light Company	June 15, 1993
	D.C. People's Counsel	929	Potomac Electric Power Company	December 16, 1993
	D.C. People's Counsel	934	Washington Gas Light Company	Filed April 22, 1994
	D.C. People's Counsel	939	Potomac Electric Power Company	March 16, 1995
	D.C. People's Counsel	917	Potomac Electric Power Company	April 16, 1995
	D.C. People's Counsel	951	Potomac Electric Power Company	February 20, 1997
	D.C. People's Counsel	945	Potomac Electric Power Company	September 29, 1999
	D.C. People's Counsel	847	Washington Gas Light Company	June 27, 2001
	D.C. People's Counsel	989	Washington Gas Light Company	May 22, 2002
	D.C. People's Counsel	1016	Washington Gas Light Company	September 23, 2003
	D.C. People's Counsel	1053	Potomac Electric Power Company	June 27, 2007
DE	Delaware PSC Staff	94-164	Artesian Water Company	Filed March 10, 1995
	Delaware PSC Staff	94-149	Wilmington Suburban Water Company	March 10, 1995
	Delaware PSC Staff	04-152	Tidewater Utilities Company	Filed July 26, 2004
FL	Florida Retail Federation	790593-EU	All Electric Utilities	March 5, 1981
	Florida Retail Federation	810002-EU	Florida Power and Light Company	July 23, 1981
	Florida Retail Federation	820097-EU	Florida Power and Light Company	September 22, 1982
	Florida Retail Federation	820097-EU	Florida Power and Light Company	April 11, 1983
	Florida Retail Federation	830012-EU	Tampa Electric Company	August 19, 1983
	Florida Retail Federation	830465-EI	Florida Power and Light Company	April 19, 1984
	Florida Retail Federation	830465-EI	Tampa Electric Company	(none)

State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
GA	Georgia Retail Federation	3270-U	Georgia Power Company	September 3, 1981
	Georgia Public Service Commission	4007-U	Georgia Power Company	August 21, 1991
	Georgia Public Service Commission	4384-U	All Electric Utilities	August 1, 1993
	Georgia Public Service Commission	4755-U	Georgia Power Company	January 25, 1994
	Georgia Public Service Commission	4697-U	All Utilities	May 10, 1994
	Georgia Public Service Commission	9355-U	Georgia Power Company	November 4, 1998
	Georgia Public Service Commission	14000-U	Georgia Power Company	October 23, 2001
	Georgia Public Service Commission	14618-U	Savannah Electric & Power Company	March 27, 2002
	Georgia Public Service Commission	14311-U	Atlanta Gas Light Company	April 8, 2002
	Georgia Public Service Commission	17066-U	Georgia Power Company	July 31, 2003
	Georgia Public Service Commission	18300-U	Georgia Power Company	October 26, 2004
	Georgia Public Service Commission	18638-U	Atlanta Gas Light Company	March 14, 2005
	Georgia Public Service Commission	19758-U	Savannah Electric & Power Company	March 29, 2005
	Georgia Public Service Commission	20298-U	Atmos Energy Corp.	October 11, 2005
	Georgia Public Service Commission	25060-U	Georgia Power Company	Filed October 22, 2007
	Georgia Public Service Commission	27163	Atmos Energy Corp.	August 16, 2008
HI	Public Utilities Department	2793	All Electric Utilities	February 14, 1978
	Hawaii Consumer Advocate	4536	Hawaiian Electric Company	February 1, 1983
IL	Illinois Retail Merchants Association ("IRMA"/ Chicago Bldg. Mgrs. Association ("CBMA")	76-0698	Commonwealth Edison	June 22, 1977
	IRMA/CBMA	76-0568	All Electric Utilities	(none)
	IRMA/CBMA	80-0546	Commonwealth Edison	March 5, 1981
	IRMA/CBMA	82-0026	Commonwealth Edison	July 22, 1982
	IRMA/CBMA	83-0537	Commonwealth Edison	March 19, 1984
	IRMA/CBMA	87-0427	Commonwealth Edison	March/April 22, 1988
	IRMA/CBMA	90-0169	Commonwealth Edison	October 29, 1990
	City of O'Fallon, IL	02-0690	Illinois-American Water Company	Filed Feb.5, Apr.11,2003
IN	Indiana Retail Council	35780-S2	N. Ind. Public Service co.	June 1, 1980
	Indiana Retail Council	35780-S1	Public Service of Indiana	October 15, 1980
	Indiana Retail Council	36318	Public Service of Indiana	May 4, 1982
KS	J.C. Penney Company	115,379-U	All Kansas Utilities	January 22, 1981

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State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
KY	Seven Kentucky Retailers	7310	Louisville Gas & Electric Co.	April 25, 1979
	Attorney General of Kentucky	2002-145	Columbia Gas of Kentucky	Filed August 8, 2002
	Attorney General of Kentucky	2003-252	Union Heat Light & Power Co.	September 30, 2003
	Attorney General of Kentucky	2004-67	Delta Gas Company	August 18, 2004
	Attorney General of Kentucky	2006-00646	Atmos Energy Corp.	Filed April 27, 2007
	Attorney General of Kentucky	2007-00008	Columbia Gas of Kentucky	Filed June 12, 2007
	Attorney General of Kentucky	2007-00089	Delta Gas Company	Filed August 14, 2007
MA	Coalition of Municipalities	20279	Western Massachusetts Electric	March 19, 1980
	Coalition of Municipalities	557/558	Western Massachusetts Electric	May 14, 1981
	Coalition of Municipalities	957	Western Massachusetts Electric	March 9, 1982
	Coalition of Municipalities	1300	Western Massachusetts Electric	January 1, 1983
	Coalition of Municipalities	85-270	Western Massachusetts Electric	March 26, 1986
MD	Maryland People's Counsel	6977	Washington Gas & Light Company	September 17, 1976
	Maryland People's Counsel	6814	Potomac Electric Power Company	
	Maryland People's Counsel	6807	All Electric Utilities	September 1, 1977
	Maryland People's Counsel	6882	Baltimore Gas & Electric Company	(none)
	Maryland People's Counsel	6985	Baltimore Gas & Electric Company	September 28, 1976
	Maryland People's Counsel	7070	Baltimore Gas & Electric Company	December 20, 1976
	Maryland People's Counsel	7149	Potomac Electric Power Company	April 18, 1978
	Maryland People's Counsel	7163	All Electric Utilities	January 17, 1979
	Maryland People's Counsel	7236	Delmarva Power & Light Company	October 23, 1978
	Retail Merchants of Baltimore	7397	Baltimore Gas & Electric Company	June 20, 1980
	Maryland People's Counsel	7427	Delmarva Power & Light Company	September 8, 1980
	Maryland People's Counsel	7574	Baltimore Gas & Electric Company	December 2, 1981
	Maryland People's Counsel	7597	Potomac Electric Power Company	February 18, 1982
	Organization of Consumer Justice	7604	Potomac Electric Power Company	April 20, 1982
	Maryland People's Counsel	7588	Baltimore Gas & Electric Company	October 19, 1982
	Maryland People's Counsel	7663	Potomac Electric Power Company	November 22, 1982
	Retail Merchants of Baltimore	7685	Baltimore Gas & Electric Company	April 12, 1983
	Genstar Stone Products, et al.	7878	Potomac Electric Power Company	December 9, 1985
	Industrial Intervenors	7878	Potomac Electric Power Company	June 28/July 1986
	Maryland People's Counsel	7983	Baltimore Gas & Electric Company	March 4, 1987
	Giant Foods, Inc.	8855	Baltimore Gas & Electric Company	January 8, 2003
	Maryland People's Counsel	9036	Baltimore Gas & Electric Company	September 29, 2006
	Maryland People's Counsel	9092	Potomac Electric Power Company	April 16, 2007
	Maryland People's Counsel	9093	Delmarva Power & Light Company	April 9, 2007
	Maryland People's Counsel	9104	Washington Gas & Light Company	August 23, 2007
	Maryland People's Counsel	9096	Baltimore Gas & Electric Company	September 24, 2007
	Maryland People's Counsel	9103	Washington Gas & Light Company	filed December 21, 2007

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State	Electric, Gas, Water Utility Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MI	General Services Administration	U-10102	Detroit Edison Company	March 22, 1993
	Michigan Attorney General	U-11722	Detroit Edison Company	November 6, 1998
	Michigan Attorney General	U-11772	Consumers Energy/Detroit Edison	November 16, 1998
	Michigan Attorney General	U-11495	Detroit Edison Company	December 8, 1999
	Michigan Attorney General	U-11956	Consumer Energy/Detroit Edison	December 15, 1999
	Michigan Attorney General	U-12505	Consumers Energy Company	September 7, 2000
	Michigan Attorney General	U-12478	Detroit Edison Company	October 5, 2000
	Michigan Attorney General	U-12639	Consumers Energy/Detroit Edison	July 18, 2001
	Michigan Attorney General	U-13000	Consumers Energy Company	January 29,2002
	Michigan Attorney General	U-13380	Consumers Energy Company	September 9, 2002
	Michigan Attorney General	U-13715	Consumers Energy Company	April 24, 2003
	Michigan Attorney General	U-13808	Detroit Edison Company	Dec 12, 2003; Jan 30, Mar 5, 04
	Michigan Attorney General	U-12999	Consumers Energy Company	March 10, 2004
	Michigan Attorney General	U-13898,9	Michigan Consolidated Gas Co.	August 23, 2004
	Michigan Attorney General	U-14201	Detroit Edison Company	Filed December 5, 2004'
	Michigan Attorney General	U-14274	Consumers Energy Company	Filed February 15, 2005
	Michigan Attorney General	U-14148	Consumers Energy Company	Filed March 2, 25, 2005
	Michigan Attorney General	U-14399	Detroit Edison Company	July 29, 2005
	Michigan Attorney General	U-14428	Detroit Edison Company	September 7, 2005
	Michigan Attorney General	U-14292	All Michigan Utilities	September 27, 2005
	Michigan Attorney General	U-13808-R	Detroit Edison Company	November 7, 2005
	Michigan Attorney General	U-14547	Consumers Energy Company	Nov.7, 2005; Mar. 22, 2006
	Michigan Attorney General	U-14701	Consumers Energy Company	March 21, 2006
	Michigan Attorney General	U-14526	Consumers Energy Company	April 11.2006
	Michigan Attorney General	U-14561	All Gas Distribution Utilities	June 1, 2006
	Michigan Attorney General	U-15002	Detroit Edison Company	December 8, 2006
	Michigan Attorney General/ABATE	U-15245	Consumers Energy Company	December 11, 2007
	Michigan Attorney General	U-15417	Detroit Edison Company	April 2, 2008
	Michigan Attorney General/ABATE	U-15244	Detroit Edison Company	July 15, 2008
	Michigan Attorney General/ABATE	U-15506	Consumers Energy Company	September 12, 2008
	Michigan Attorney General	U-15002-R	Detroit Edison Company	October 16, 2008
MN	Minnesota Retail Federation	EOO2/6R-77-611	Northern States Power	1979
MO	Missouri Retailers Association	EO-78-161	Kansas City Power & Light Company	February 19, 1981
	Missouri Public Counsel	ER-2006-0315	Empire District Electric Company	September 14, 2006
	Missouri Public Counsel	GR-2007-0003	Ameren UE (Gas)	Filed December 15, 2006
	Missouri Public Counsel	ER-2007-0002	Ameren UE (Electric)	March 22, 2007
NC	North Carolina Merchants Association	E-100	All Electric Utilities	December 18, 1975

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State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
ND	North Dakota Public Service Commission	PU-400-00-521	Xcel Energy, Inc.	April 20, 2001
	North Dakota Public Service Commission	PU-399-01-186	Montana-Dakota Utilities (Electric)	February 25, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas)	October 7, 2002
	North Dakota Public Service Commission	PU-399-02-183	Montana-Dakota Utilities (Gas Depr.)	Filed April 7, 2003
	North Dakota Public Service Commission	PU-399-03-296	Montana-Dakota Utilities (Electric)	Filed October 15, 2003
	North Dakota Public Service Commission	PU-04-97	Montana-Dakota Utilities (Gas)	Filed July 6, 2004
	North Dakota Public Service Commission	PU-06-525	Northern States Power (Gas)	Filed May 1, 2007
	North Dakota Public Service Commission	PU-07-776	Northern States Power (Electric)	June 25, 2008
NH	Business & Industry Association of N.H.	79-187-II	Public Service of N.H.	February 6, 1981
	Business & Industry Association of N.H.	80-260	Public Service of N.H.	February 5, 1981
	Business & Industry Association of N.H.	82-333	Public Service of N.H.	November 2, 1983
NJ	N.J. Retail Merchants Association	803-151	All New Jersey Utilities	March 31, 1981
	Department of Public Advocate	815-459	N.J. Natural Gas Company	(none)
	Resorts International Hotel, Inc.	8011-827	Atlantic City Sewerage Co.	(none)
	Dept. of Public Advocate	822-116	Atlantic City Electric Co.	August 11, 1982
	Dept. of Public Advocate	355-87	Elizabethtown Gas	June 9, 1987
	Dover Township Fire Chiefs	88-080967	Tom's River Water Company	February 22, 1989
NY	NY Council of Retail Merchants	26806	All Electric Utilities	February 3. 1976
	Metropolitan N.Y. Retail Council	27029	Consolidated Edison Company	(none)
	Metropolitan N.Y. Retail Council	27136	Long Island Lighting Company	July 1, 1977
	N.Y. Metro. Transit Authority	27353	Consolidated Edison Company	September 5, 1980
OH	Ohio Council of Retail Association	88-170-EL	Cleveland Elec. Illuminating	(none)
	Ohio Council of Retail Association	83-1529-EL	Cincinnati Gas & Electric	February 15, 1992
	Ohio Energy Group	08-936-EL-SSO	FirstEnergy Companies	Filed September 25, 2008

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Appearances before State Regulatory Agencies

State	Electric, Gas, Water Utility Cases			Date
	Client	Case		
		Case Number	Utility	
PA	Pennsylvania Retail Association Southeastern Pa. Transp. Authority Eastern Penn Energy Users Group Eastern Penn Energy Association Penn Business Utility User Group Pennsylvania Office of Consumer Advocate Pennsylvania Office of Public Advocate	76-PRMD-7 R-811626 R-822169 R-842651 R-850152 R-00016339 R-2008-203289	All Electric Utilities Philadelphia Electric Company Penn. Power & Light Company Penn. Power & Light Company Philadelphia Electric Company Pennsylvania-American Water Co. Pennsylvania-American Water Co.	September 7, 1977 December 11, 1981 March/April 1983 December 3, 1984 February 19, 1986 September 19, 2001 August 6, 2008; Sept.15, 2008
TN	Attorney General of Tennessee Attorney General of Tennessee	07-00105 08-00039	Atmos Energy Corp. Tennessee-American Water Co.	Filed August 21, 2007 August 26, 2007
TX	Houston Retailers Association Houston Retailers Association Cities for Fair Utility Rates	5779 6765 8425/8431	Houston Lighting Company Houston Lighting Company Houston Lighting Company	October 19, 1984 September 25, 1986 April 25, 1989
UT	Div. Of Public Utilities Dept of Commerce Div. Of Public Utilities Dept of Commerce Div. Of Public Utilities Dept of Commerce	98-2035-33 05-057-T01 07-035-13	Pacific Corp Questar Gas Company Rocky Mountain Power Co.	Filed August 16, Sept 22, 1999 May 17, 2006 Filed October 15, 2007
VA	Consumer Congress of Virginia Consumer Congress of Virginia Va. Business Committee on Energy Virginia Pipe Trades Council	19426 19960 PUE 7900012 PUE 8900051	Virginia Electric Power Company Virginia Electric Power Company Virginia Electric Power Company Old Dominion Electric Corp. &	July 1, 1975 September 19, 1978 February 25, 1981 October 31, 1989
WA	WA Attorney General - Public Counsel WA Attorney General - Public Counsel WA Attorney General - Public Counsel	UE-072300;UG-072301 UE-080220 UE-08416;UG-08417	Puget Sound Energy PacifiCorp Avista Utilities	Filed May 30, 2008 Filed August 15, 2008 September 19;October 10, 2008
WI	Wisconsin Merchants Federation	6630-ER-2	Wisconsin Electric Power Company	May 15, 1978

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
AL	U.S. Department of Defense	24472	All Telephone Companies	June 14, 1995
AK	GCI Communications, Inc. GCI Communications, Inc.	U-97-82,U-97-143 U-05-46	Alaska Communications Systems Matanuska Telephone Association	Filed Feb 25, April 5, 2004 October 28, 2005
AZ	Arizona Burglar & Fire Alarm Association Arizona Burglar & Fire Alarm Association Federal Executive Agencies U.S. Department of Defense	9981-E- 1051-80-64 E-1051-88-146 T-01051B-99-0105	Mountain State Telephone Mountain State Telephone Mountain State Telephone US WEST Communications	(none) (none) Filed July 26, Sept 8, 2000
CA	Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association Western Burglar & Fire Alarm Association California Cellular Resellers Federal Executive Agencies California Cellular Resellers Cellular Services, Inc. Federal Executive Agencies	59849 5984cont. A83-01-22 A83-02-02 A82-11-07 A85-01-034 A87-01-02 A88-07-17019 A.88-11-1040 1.87-11-033 1.88-11-040 1.88-11-040 A92-05-004	Pacific Telephone & Telegraph Pacific Telephone & Telegraph Pacific Telephone & Telegraph General Telephone of California Pacific Telephone & Telegraph Pacific Telephone & Telegraph General Telephone of California Pac. Bell Tel. & GTE of CA. All Cellular Carriers All Telephone Companies All Cellular Carriers All Cellular Carriers Pacific Telephone & Telegraph	March 25, 1981 June 23, 1982 June 29, 1983 January 17, 1984 Jan. 18, Oct. 31, Nov 28, 1984 June 4, 1985, October 2, 1986 October 22, 1987 January 23, 1989 August 11, 1989 March 6-7, 1991 August 19, 1991 October 3, 1991 June 9, 1993
CO	U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense Colorado Municipal League U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense AT&T	I&S 717 I&S 1700 Appl. I&S 1766 Appl 36883 I&S 891-O82T 905-544T 90A-665T 92M-039T 92S-229T 90A-665T 96S-331T	Mountain Bell Telephone Company Mountain Bell Telephone Company Mountain Bell Telephone Company Mountain Bell Telephone Company Mountain Bell Telephone Company U.S. West Communications U.S. West Communications U.S. West Communications U.S. West Communications U.S. West Communications U.S. West Communications U.S. West Communications	1972 (none) September 18, 1986 November 28, 1988 December 13, 1988 February 21, 1990 July 17, 1991 October 23, 1991 February 24-24, 1992 July 30-31, 1992 November 6, 1996 April 17, 1997

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
CT	Connecticut Consumer Counsel	770526	Southern New England Telephone Co.	November 10, 1977
	CT Cellular Resellers Assn.	89-12-05	Southern New England Telephone Co.	(none)
	CT Cellular Resellers Coalition	94-03-27	Springwich Cellular/Bell Atlantic	May 16, June, 1994
	AT&T	AT&T/SNET Arbitration	Southern New England Telephone Co.	Filed October 28, 1996
	Connecticut Consumer Counsel	96-04-07	Southern New England Telephone Co.	February 10,1998
	Connecticut Consumer Counsel	00-07-17	Southern New England Telephone Co.	December 5, 2000
DC	D.C. People's Counsel	729	Chesapeake & Potomac Tel. Co.	May 13, 1980
	D.C. People's Counsel	798	Chesapeake & Potomac Tel. Co.	July 18, 1983
	General Services Administration	827	Chesapeake & Potomac Tel. Co.	May 7, 1985
	General Services Administration	854	Chesapeake & Potomac Tel. Co.	April 16, 1987
	General Services Administration	850	Chesapeake & Potomac Tel. Co.	October 7, 1991
	General Services Administration	926	Chesapeake & Potomac Tel. Co.	October 7, 1993
DE	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	April 1, 1985
	Federal Executive Agencies	86-20	Diamond State Telephone Co.	July 31, 1987
	Public Service Commission	Depr.Repre	Diamond State Telephone Co.	March 8, 1988
FL	GTE Sprint Communications Company	720536-TP	All Telephone Companies	September 12, 1983
	Office of Public Counsel	Depr.Repre	Southern Bell	July 30, 1986
	Federal Executive Agencies	880069-TL	Southern Bell	July 21, 1988
	Federal Executive Agencies	880069-TL	Southern Bell	November 30, 1990
	Federal Executive Agencies	880069-TL	Southern Bell	February 11, 1992
GA	Georgia Attorney General	3893-U	Southern Bell Telephone Co.	January 8, 1990
	Federal Executive Agencies	3905-U	Southern Bell Telephone Co.	June 12, 1990
	Federal Executive Agencies	3987-U	Southern Bell Telephone Co.	February 13, 1992
	Georgia Public Service Commission	4018-U	Southern Bell Telephone Co.	Jan 14, Feb 10, 1993
HI	Hawaii Public Utility Commission	1871	Hawaiian Telephone Company	July 8, 1971
	Four Hawaii Counties	4588	Hawaiian Telephone Company	December 15, 1983
	Department of Defense	7579	Hawaiian Telephone Company	April 26, 1994
	Department of Defense	94-0093	Oceanic Communications	March 13, 1995
	Department of Defense	7702	All Communications Carriers	June 2, 1995
	Department of Defense	94-0298	GTE Hawaiian Telephone Company	May 7, 1996
	Department of Defense	7720	Verizon-Hawaii	November 15, 2000

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
ID	U.S. Department of Energy U.S. Department of Energy	U-1000-63 U-1000-70	Mountain Bell Telephone Co. Mountain Bell Telephone Co.	May 16, 1983 March 6, 1984
IL	Illinois Alarm Companies Attorney General of Illinois GTE Sprint Communications Co. Federal Executive Agencies	79-0143 81-0478 83-0142 89-0033	Illinois Bell Telephone Illinois Bell Telephone All Telephone Companies Illinois Bell Telephone	September 26, 1979 December 28, 1981 August 4, 1983 June 12, 1989
KS	State Corporation Commission Federal Executive Agencies Federal Executive Agencies	Depr. Repr. 166.856-U 190, 492	Southwestern Bell Southwestern Bell All Telephone Companies	May 12-14, 1986 November 7, 1989 November 4, 1994
KY	Kentucky Cable Telecommunications Assn. Kentucky Cable Telecommunications Assn.	2000-414 2000-39	Blue Grass Energy Cooperative Cumberland Valley Electric, Inc.	January 11, 2001 January 11, 2001
MD	Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Maryland People's Counsel Federal Executive Agencies Federal Executive Agencies Federal Executive Agencies	6813 6881 7025 7467 7851 8106 8274	C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company C&P Telephone Company	1975 December 17, 1975 March 15, 1975 October 20, 1981 March 20, 1985 May 9, 1988 August 2, 1990
MI	Michigan Attorney General Michigan Attorney General	U-8911 U-9553	Michigan Bell Telephone Co. AT&T Communications/MCI	November 7, 1988 December 4, 1990
MN	GTE Sprint Communications Co. U.S. Department of Defense	83-102-HC 87-021-BC	All Telephone Companies Northwest Bell Telephone Co.	August 5, 1983 (none)

State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
MO	GTE Sprint Communications Co. Federal Executive Agencies Federal Executive Agencies	TR83-253 TC-89-14 TO-89-56	Southwestern Bell Tel. Co. Southwestern Bell Tel. Co. Southwestern Bell Tel. Co.	September 5, 1983 (none) November 7, 1990
MS	Federal Executive Agencies	U-5453	South Central Bell Tel. Co.	May 15, 1990
NJ	Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate Department of Public Advocate	Depr.Repr. 815-458 Depr.Repr. Depr.Repr. T092030358 TMO05080739	N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company N.J. Bell Telephone Company United Telephone Co. of New Jersey	Mar-79 October 15, 1981 March 1, 1982 February 1, 1985 September 30, 1992 January 5,2006
NM	New Mexico Corporation Commission New Mexico Corporation Commission	1032 86-151-TC	Mountain Bell Telephone Co. General Telephone of Southwest	November 14, 1983 February 5, 1987
NV	Prime Cable of Las Vegas Prime Cable of Las Vegas	95-8034/8035 96-9035	Central Telephone - NV Sprint/Centel, Nevada Bell	Filed November 22, 1995 June 2, 1997
NY	Holmes Protection, Inc. Holmes Protection, Inc. 5 Alarm Companies GTE Sprint Communications Co.	27350 27469 27710 28425	New York Telephone Company New York Telephone Company New York Telephone Company All Telephone Companies	October 17, 1978 May 17, 1979 July 24, 1980 July 8, 1983
PA	City of Philadelphia	R-832316	Pennsylvania Bell Telephone	September 20, 1983
SC	Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate Office of Consumer Advocate	Depr.Repr. 86-511-C 86-541-C Depr.Repr. 89-180-C	Southern Bell Southern Bell General Telephone of South Southern Bell ALLTEL of South Carolina	July 1, 1986 December 11, 1986 April 8, 1987 July 10, 1989 September 26, 1989

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State	Telecommunications Cases			Date of Cross-Examination
	Client	Case		
		Case Number	Utility	
TX	U.S. Department of Defense	8585/8218	Southwestern Bell Telephone Co.	(none)
VA	U.S. Dept. Of Defense, GSA, et Federal Executive Agencies	19696 PUC 890014	C&P Telephone Company All Telephone Companies	October 6, 1976 February 13, 1989
VI	V.I. Department of Commerce V.I. Public Service Commission	205 341	Virgin Islands Telephone Co. Virgin Islands Telephone Co.	April 29, 1980 March 20, 1991
WA	U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER U.S. Department of Defense U.S. Department of Defense WA Attorney General/TRACER WA Attorney General/TRACER U.S. Department of Defense WA Attorney General/WeBTEC/AARP WA Attorney General WA Attorney General	U-72-39 U-87-796-T U-88-20524 U-89-2698-F UT-940641 UT-941464 UT-951425 UT-961632 UT-021120 UT-040788 UT-040520 UT-050814	Pacific Northwest Bell Pacific Northwest Bell Pacific Northwest Bell US West Communications US West Communications US West Communications US West Communications US West Communications GTE Northwest, Inc Qwest Communications Verizon Northwest, Inc. Verizon Northwest, Inc. Verizon - MCI Merger	1973 December 20, 1983 November 8, 1988 November 28, 1989 Filed October 14, 1994 June 22, 1995 January 22, 1996 Filed June 23, 1997 July 29, 1997 May 22, 2003 August 12, 2004 February 2, 2005 November 2, 2005
WI	GTE Sprint Wisconsin Consumers Utility Board Wisconsin Consumers Utility Board	6720-TR-38 2055-TR-102 5846-TR-102	All Telephone Companies CenturyTel of Central Wisconsin Telephone USA, LCC	October 20, 1983 June 26, 2002 June 26, 2002

Federal Communications Commission			
Client	**Docket**	**Subject**	**Date of Cross-Examination**
Department of Defense	16020	Consat Rate of Return	1973
Airline Parties	16258	Bell System Rates	July 22, 1968
Airline Parties	18128	TELPAK	3/22, 10/15 1971, Feb. 22, 1972
National Data Corporation	19989	WATS	(none)
Press Wire Services	19919	Private Line Rates	(none)
Aeronautical Radio	20814	Private Line Rates	October 5, 1978
Department of Defense	20690	1,544 Mbps Service	January 30, 1979
State of Hawaii	21263	Interstate Separation	February 7, 1979
International Record Carriers	CC78-97	Telex/TWX Rates	March 6, 1980
ITT World Communications	CC84-633	Rate of Return	(none)
Aeronautical Radio	CC78-72	Access Line Charges	(none)
MCI	CC84-800	Rate of Return	(none)
Ind. Data Com. Mfg. Assn.	CC85-26	AT&T Accounting Plan	(none)
Tymnet, Inc.	ENF84-22	Packet Switching Costs	(none)
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 7/29/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 8/23/94
Adelphia Jones Intercable, et. al.	Bell Atlantic	Video Dialtone	Filed 2/21/95
Nuclear Regulatory Commission			
Fauquier League for Environment Protection	50-328 50-329	Va. Electric Power Co.	1976
Postal Rate Commission			
Association of Third Class Mail Users	R71-1	Rates	1970
Dow Jones & Company	R72-1	Rates	1972
Dow Jones & Company	R74-1	Rates	September 13, 1974
Dow Jones & Company	MC76-2	Rate Structure	January 6, 1979
Dow Jones & Company	MC79-3	Rate Structure	September 12, 1979
Dow Jones & Company	R80-1	Rates	November 25, 1980
Warshawsky & Company	C82-1	Rate Structure	(none)
Dow Jones & Company	R84-1	Postal Costs	June 14, 1984
Dow Jones & Company	R87-1	Rate Structure Costs	November 2, 1987
Dow Jones & Company	R90-1	Rate Structure Costs	Sept 12, Oct 10, 1990
Dow Jones & Company	MC91-1	Pre-barcoding Discounts	November 19, 1991
Dow Jones & Company	MC91-3	Palletization Discounts	March 2, 1992

Client	Docket	Subject	Date of Cross-Examination
U.S. Congress			
National Retail Merchants Association	House/Senate Hearings	Electric Rate Reform Legislation	1976, 1977 & 1979
National Wireless Resellers Association	House Commerce Committee	Interconnection & Resale of Wireless Services	October 12, 1995
Federal Maritime Commission			
State of Hawaii	71-18	Ocean Shipping Rates	October-71
Foss Alaska Line	79-54	Barge Rate Increase	July 1979
Palmetto Shipping and Stevadoring	85-20	Vessel Charge Liability	October 27, 1986
Interstate Commerce Commission - Surface Transportation Board			
Western Coal Traffic League	Ex Parte 349	R.R. Rate Increase	May-76
Western Coal Traffic League	Ex Parte 357	R.R. Rate Increase	Oct-78
Western Coal Traffic League	Ex Parte 375 (Sub1)	R.R. Rate Increase	June 1, 1980
Arkansas Power & Light Co.	37276	Cost of Capital	(none)
Central Illinois Light Co.	37450	Cost of Capital	March 10, 1981
Western Coal Traffic League	Ex Parte 347	Costing Methods	(none)
Snavely King Majoros O'Connor & Lee, Inc.	Ex Parte 664	Cost of Capital	December 8, 2006
Williams Energy Services, Inc	Ex Parte 582, Sub 1	Rail Merger Guidelines	April 5, 2001
Civil Aeronautics Board			
Thomas Cook, Inc.	36595	Air Fare Deregulation	(none)
Copyright Royalty Tribunal			
Public Broadcasting Service	88-2-86CD	Television Valuation	(none)

CHARLES W. KING
Appearances before Federal Regulatory Agencies

Client	Docket	Subject	Date
Federal Energy Regulatory Commission			
Exxon USA	OR89-2-000	Pipeline Quality Bank	October 18, 1990
Consumer Advocates of DE,DC,OH,MD,NJ,PA,WV,VA	ER08-386-000	Electric Transmission Cost of Equity	March 26, 2008
Consumer Advocates of DE,DC,OH,MD,NJ,PA,WV	ER08-23-000	Electric Transmission Cost of Equity	May 21, 2008
Maryland Office of People's Counsel	ER08-686-01	Electric Transmission Cost of Equity	April 7, 2008; July 8, 2008,
Maryland Office of People's Counsel	ER08-1329	Electric Transmission Cost of Equity	August, 2008
Canadian Transport Commission			
Rail Costing Inquiry, 1967-1969 Telecommunications Costing Inquiry, 1972-1975			

OTTER TAIL POWER COMPANY
REVISED SERVICE ALLCOCATORS

			TOTAL N. D.	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	Investment per Service	Marginal Cost Study, Table 16		406.10	434.72	592.07	26,611.21	406.10		687.11		26,611.21	26,611.21
2	Secondary Service Locations	COSS, p 15-2, Factor C3	59,901	46,011	1,091	11,876	132	69	33	572	18	85	14
3	Total Service Investment	Ln 8 * Ln 9	32,759,007	18,685,067	474,280	7,031,423	3,512,680	28,021	-	393,027	-	2,261,953	372,557
4	Revised Service Allocator (C3)	Ln 10 Percentages	100.0000%	57.0380%	1.4478%	21.4641%	10.7228%	0.0855%	0.0000%	1.1998%	0.0000%	6.9048%	1.1373%

Marginal Cost Study: Attachment 1 to ND PSC IR 1-39

OTTER TAIL POWER COMPANY
ND PSC STAFF CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	NORTH DAKOTA	RESIDENTIAL	GENERAL SERVICE	LARGE GENERAL SERVICE	FARMS	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	RATE BASE	187,173,203	57,573,505	50,431,292	49,499,960	3,190,190	196,644	5,826,169	1,918,709	3,897,899	12,706,764	1,932,070
2												
3	TOTAL AVAILABLE FOR RETURN	12,942,144	3,591,304	5,878,705	4,899,851	85,514	(8,223)	(63,316)	(1,607)	(126,917)	(1,279,628)	(33,539)
4												
5	RATE OF RETURN EARNED	6.91%	6.24%	11.66%	9.90%	2.68%	-4.18%	-1.09%	-0.08%	-3.26%	-10.07%	-1.74%
6												
7	RATE OF RETURN REQUESTED	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%	6.91%
8												
9	OPERATING INCOME REQUIRED	12,942,144	3,980,936	3,487,086	3,422,689	220,587	13,597	402,852	132,670	269,521	878,613	133,594
10												
11	TOTAL AVAILABLE FOR RETURN	12,942,144	3,591,304	5,878,705	4,899,851	85,514	(8,223)	(63,316)	(1,607)	(126,917)	(1,279,628)	(33,539)
12												
13	OPERATING INCOME DEFECIENCY	-	389,632	(2,391,619)	(1,477,162)	135,073	21,820	466,168	134,277	396,438	2,158,240	167,132
14												
15	INCREMENTAL TAXES	0	251,474	(1,543,582)	(953,380)	87,178	14,083	300,871	86,664	255,867	1,392,956	107,869
16												
17	REVENUE CHANGE REQUIRED	0	641,106	(3,935,201)	(2,430,542)	222,250	35,904	767,039	220,941	652,305	3,551,197	275,001
	REVENUE AT PRESENT RATES	118,309,177	36,574,921	34,012,150	36,231,788	1,601,767	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
18												
19	PERCENTAGE CHANGE	0.00%	1.75%	-11.57%	-6.71%	13.88%	78.11%	36.60%	22.83%	55.03%	74.85%	32.37%

Source: Attachment 1 to ND PSC IR 1-36

OTTER TAIL POWER COMPANY
STAFF RECOMMENDED CLASS RATE ADJUSTMENTS
BASED ON CLASS COST OF SERVICE STUDY (CCOSS) TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	SOURCE	A NORTH DAKOTA	B RESIDENTIAL	C GENERAL SERVICE	D LARGE GENERAL SERVICE	E FARMS	F IRRIGATION	G OUTDOOR LIGHTING	H OPA	I CONTROLLED WATER HEATING	J CONTROLLED SERVICE INTERRUPT	K CONTROLLED SERVICE DEFERRED
1	RATE BASE	2007 CCOSS, Excel Ln 15	187,173,203	57,324,168	50,593,875	49,539,005	3,199,920	197,178	5,826,067	1,926,610	3,897,780	12,732,425	1,936,176
2	TOTAL AVAILABLE FOR RETURN	2007 CCOSS, Excel Ln 17	12,942,144	3,591,304	5,878,705	4,899,851	85,514	(8,223)	(63,316)	(1,607)	(126,917)	(1,279,628)	(33,539)
3	RATE OF RETURN EARNED	Ln 2/ Ln 1	6.91%	6.26%	11.62%	9.89%	2.67%	-4.17%	-1.09%	-0.08%	-3.26%	-10.05%	-1.73%
4	REVENUE AT PRESENT RATES - CCOS	2007 CCOSS. Excel Ln 577	118,309,177	36,574,921	34,012,150	36,231,788	1,601,767	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
5	RATE INCREASE	Assumed	2.0%										
6	REVENUE INCREASE		2,366,184										
7	REVENUE REQUIREMENT	Ln 4 * Ln 5	120,675,361										
RESIDENTIAL CLASS													
8	RESIDENTIAL INCREASE AT CO. AVERAGE	Ln 4 * Ln 5	731,498	731,498									
REVENUE DEFICIENT CLASSES:													
9	COMPANY PROPOSED INCREASE %	Beithon Test. P. 61					7.50%	10.0%	25.0%	14.0%	10.0%	35.0%	11.0%
10	REVENUE INCREASE	Ln 4 * Ln 8	2,656,637				120,133	4,596	523,917	135,460	118,533	1,660,541	93,458
REVENUE SUFFICIENT CLASSES:													
11	REVENUE ADJUSTMENT	Ln 6 - Ln 8 - Ln 10	(1,021,952)										
12	ROE EXCESS	Ln 3, Class - Co. ROR			4.70%	2.98%							
13	RETURN EXCESS	Ln 1 * Ln 12	3,854,840		2,380,377	1,474,463							
14	ALLOCATION OF AVAILABLE REVENUE	Ln 11 by Ln 13	(1,021,952)		(631,059)	(390,893)							
15	RATE REDUCTION	Ln 14/Ln 4			-1.86%	-1.08%							
SUMMARY													
16	RATE ADJUSTMENT PERCENT	Lns 5, 9, 1516	2.00%	2.00%	-1.86%	-1.08%	7.50%	10.00%	25.00%	14.00%	10.00%	35.00%	11.00%
17	RATE ADJUSTMENT - REVENUE	Ln 17 * Ln 5	2,366,184	731,498	(631,059)	(390,893)	120,133	4,596	523,917	135,460	118,533	1,660,541	93,458

CCOSS: ATTACHMENT 1 TO ND PSC IR 01-036

Exhibit_____(CWK-4)

Otter Tail Power's response to ND PSC IR No. 03-002

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-862

Response to:	North Dakota Public Service Commission
Analyst:	Diller_King_03
Date of Request:	2/27/2009
Date Received:	2/27/2009
Date Due:	3/27/2009

Information Request No. ND 03-002

Staff is concerned with the very large increases that some customers will experience under the revised rate structures proposed by OTP, quite regardless of the overall level of revenue increase. Staff is considering a recommendation of limiting any one customer's rate increase to 50% over the class increase or, for those classes receiving less than a 6.7% increase, 10 percent on an annualized basis in the first year. Subsequent annual increases would be capped at 5 percent until the proposed rates are fully implemented. Exceptions would be customers with average monthly bills of less than $10 and customers who are able to switch to other rate schedules that would result in increases below the cap limits. The revenue shortfall from the capped bills would be made up in the form of across-the-board increases on all other customers.

a. Would OTP oppose this plan and, if so, why?
b. What would be the obstacles to implementing this plan?
c. Can OTP recommend an implementation program for this plan?

RESPONSE:

OTP has reviewed its proposed rate design with the above parameters in mind. The following response discusses the results of that review and suggests rate design modifications that could meet the majority of the parameters suggested in this IR without the need for a "phasing-in" of rate design.

a. OTP does not oppose the majority of Staff's proposal, but, as explained in this response, OTP would prefer to establish a rate design in this case that does not require the design to be "phased-in." Therefore, OTP is providing an alternative rate design in this response that would not require a phasing-in, while both accommodating the majority of the Staff's recommended increase limitations and most of OTP's rate design objectives (including those that would make progress toward meeting the new Federal Economic Stimulus package's goals of efficient use of energy (Section 410)). See OTP's Attachment 1 to IR ND 03-002 for details on this alternative proposal.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

b. There are a few obstacles to a "phase-in" approach to rate design. Such an approach would add significant additional administrative expense in developing and implementing each phase of such a plan, however designed. Additional customer notices would need to be provided in years subsequent to final rates in this case. Those notices and the frequency of rate adjustments during the phase-in period would likely be confusing to many customers. An obstacle might also be created by phasing-in rate design, as OTP expects that it may file another general rate case within three years. It would be an obstacle to implement any portion of the phase-in of rate design at the same time interim rates for the next case are being applied.

   If a current non-phase-in approach is taken to accommodate the request, as proposed in Attachment 1 to IR ND 03-002, there is an obstacle to meeting precisely each criteria identified in the Staff's request. However, because the proposal included in Attachment 1 to IR ND 03-002 comes so very near to meeting each criteria of the request and does not require a phasing-in, OTP believes it is preferable to a plan that would phase-in rate design changes.

c. Attachment 1 to IR ND 03-002 is OTP's matrix of rates, issues and explanations relating to OTP's recommended alternative to meeting Staff's request. As explained in that attachment, there are some rates (very few) that cannot be reasonably adjusted to meet the precise limitations recommended by Staff. OTP's footnotes in the attachment explain the logic of why these few rates should not be adjusted. There are four basic categories into which OTP's rates fall compared to the increase limitations suggested in Staff's request:

   i. Category 1. OTP's originally proposed rate meets the criteria without any change. These rates include: Large General Service, Large General Service Off-Peak Rider, Irrigation Option 1 and Controlled Service-Interruptible Load (CT Metering) Rider.

   ii. Category 2. The rate is being cancelled. When looking at the duo-decile chart for the rate, the impact shown is that of customers moving to other rates. The duo-decile is not for the cancelled rate. These rates include: Commercial Demand Control Customers Billed on Small General Service Less Than 20 kW, Electric Climate Control Customers Billed on Small General Service Less Than 20 kW, Commercial Demand Control Customers Billed on General Service Equal to and Greater Than 20 kW Electric Climate Control and Customers Billed on General Service Equal to and Greater Than 20 kW.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

iii. Category 3. OTP has modified its originally proposed rate to accommodate Staff's increase limitations. OTP's modifications include moving revenue requirements to another rate in the class, adding a declining block component to the rate, or modifying the customer and/or facilities charge. These rates include: Residential Service, Residential Controlled Demand, and Farm Service.

iv. Category 4. OTP's originally proposed rate is very close to meeting Staff's increase limitation, but does not exactly meet all limitations. These rates include: Small General Service Less Than 20 kW, Small General Service 20 kW and Greater, Irrigation Option 2, Municipal Pumping, Civil Defense-Fire Siren, Water Heating – Controlled Service Rider, Controlled Service-Interruptible Load (Self-Contained) Rider, Deferred Load Rider Fixed Time of Delivery (Self-Contained Meter) Rider and Fixed Time of Delivery (CT Meter) Rider.

OTP determined the parameters of this IR as follows, based on its understanding of the request: Limit rate increases to 50% over the class increase and, for those classes receiving less than a 6.7% increase, limit the increase to 10%. OTP's plan limits the increase at the duo-decile level.

Attachment 1 to IR ND 03-002 lists the duo-decile figures, from Mr. Prazak's testimony, that prior to any modifications would have met or not met the limiting criteria recommended by Staff's request. Out of the 22 duo-decile figures, 17 duo-decile figures have one or more duo-deciles that would have exceeded the limitations.

For those duo-deciles that did not meet the limiting criteria, a different set of criteria (impacts from dollar and percent, usage predictability, and rates to be closed) were identified and catalogued for each of the 17 duo-decile figures. Based on these results, OTP selected three rate designs for adjustments based mainly on the criteria contained in B1 or B4 (i.e. percent impacts) listed at the bottom of Attachment 1 to IR ND 03-002.

Attachment 2 to IR ND 03-002 contains the three rate design adjustments identified in column H of Attachment 1 to IR ND 03-002, with one exception (Municipal Pumping, which is explained later). The adjustment techniques used included: (1) changing customer and/or facilities charge; (2) re-introducing declining blocks; and (3) shifting revenue requirements within a class (e.g., Residential Demand Control to Residential Service). Shifting revenue requirements across classes was not used.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

As shown in Attachment 2 to IR ND 03-002, each of the three rate design adjustments shows two duo-decile bar graphs (on the left - per Mr. Prazak's testimony, and on the right – a revised duo-decile graph to meet the criteria recommended by Staff). Below the duo-decile graphs are the originally proposed and revised rate designs.

The Municipal Pumping duo-decile is included for discussion purposes. Even though it received a B4 criterion (i.e. only the last duo-decile exceeded the limit), the rate re-design was not performed as it only exceeded the limit by one (1) percent.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

OTP's Overall Matrix of Results - Limiting Bill Impacts & Potential Rate Design Adjustments

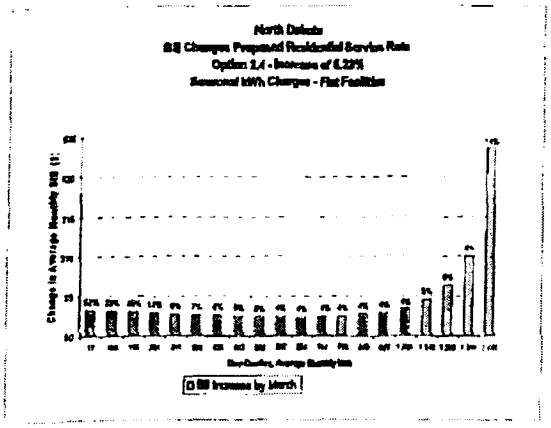
A	B	C	D	E	F	G	H
Figure No.	Figure Name in Testimony (Prazak)	Customer Class	Otter Tail's Requested Class Increase	Upper-Limit Class Increase Per ND-03-002	Any Duo-Decile Above Upper Limit	Criteria to Determine Rate Design Adj.	Adj. Rate Design Proposal
Figure 1	Residential Service	Residential	7 50%	11.25%	Yes	A1, B5	Yes
Figure 2	Residential Controlled Demand	Residential	7 50%	11.25%	Yes	B1	Yes
Figure 3	Farm Service	Farm	7 50%	11 25%	Yes	A1, B4, B5	Yes
Figure 4	Small General Service Less Than 20 kW	General Service	0 95%	10 00%	Yes	A1, B5	-
Figure 5	Commercial Demand Control Customers Billed on Small General Service Less Than 20 kW	General Service	0 95%	10 00%	Yes	B2, D	-
Figure 6	Electric Climate Control Customers Billed on Small General Service Less Than 20 kW	General Service	0 95%	10 00%	Yes	A1, D	-
Figure 7	Small General Service 20 kW and greater	General Service	0 95%	10.00%	Yes	A1	-
Figure 8	Commercial Demand Control Customers Billed on General Service Equal to and Greater Than 20 kW	General Service	0 95%	10 00%	Yes	A1, B4, D	-
Figure 9	Electric Climate Control Customers Billed on General Service Equal to and Greater Than 20 kW	General Service	0 95%	10 00%	Yes	B2, D	-
Figure 10	Large General Service	Large General Service	1 00%	10 00%	-	-	-
Figure 11	Large General Service Off Peak Rider Customers billed on the Large General Service Rate	Large General Service	1 00%	10.00%	-	-	-
Figure 12	Irrigation Option 1	Irrigation	10 00%	15 00%	-	-	-
Figure 13	Irrigation Option 2	Irrigation	10 00%	15 00%	Yes	C	-
Figure 14	Municipal Pumping	Other Public Authority	14 00%	21 00%	Yes	A1, A2, B4, B5	-
Figure 15	Civil Defense-Fire Siren	Other Public Authority	14 00%	21 00%	Yes	A2, B2	-
Figure 16	Water Heating -Controlled Service Rider	Controlled Water Heating	10 00%	15 00%	Yes	A1, A2, B5	-
Figure 17	Controlled Service-Interruptible Load (CT Metering) Rider	Interruptible	35 00%	52 50%	-	-	-
Figure 18	Controlled Service-Interruptible Load (Self-Contained) Rider	Interruptible	35 00%	52 50%	Yes	B5	-
Figure 19	Standby Service	Interruptible	35 00%	52 50%	-	-	-
Figure 20	Deferred Load Rider	Deferred Load	11 00%	16 50%	Yes	B5	-
Figure 21	Fixed Time of Delivery (Self-Contained Meter) Rider	Deferred Load	11 00%	16 50%	Yes	A1, B4	-
Figure 22	Fixed Time of Delivery (CT Meter) Rider	Deferred Load	11.00%	16 50%	Yes	B1	-
					17		3

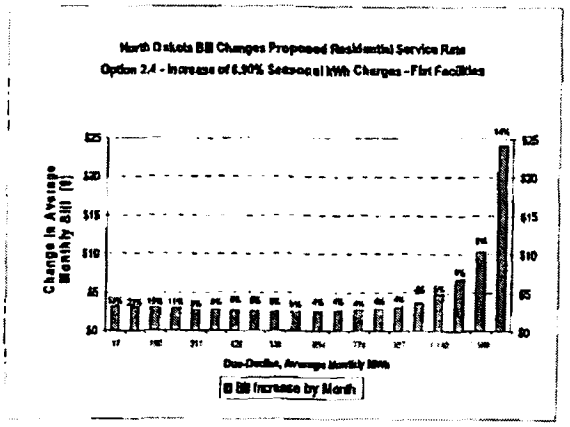
Legend

A Dollar ($) Bill impact levels/month	A1	Some monthly bill impacts around or less than $5/month
	A2	All or some duo-decile bill impacts less than $1/month
B Percent (%) Bill impact levels/month	B1	All duo-deciles exceed limits
	B2	Majority of duo-deciles exceed limits
	B3	Only first duo-decile bill impact exceeds limit
	B4	The last three or less duo-decile bill impacts exceeds limit
	B5	Majority of duo-deciles do not exceed limits
C Usage - Small Class	C	Rate Design difficult to adjust for few customers with unpredicable usage
D Rates Proposed to be Eliminated	D	Rates Proposed to be eliminated
	-	Not Applicable

Residential Service

41,638 customers, 2,082 per a decile

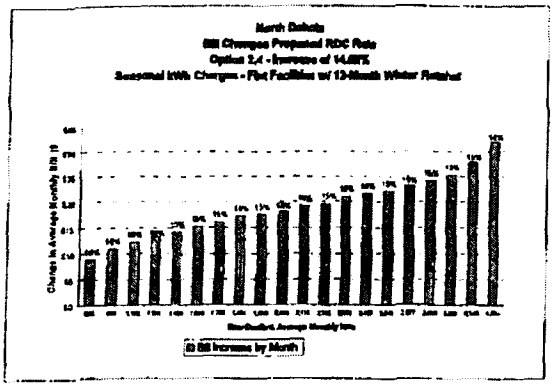


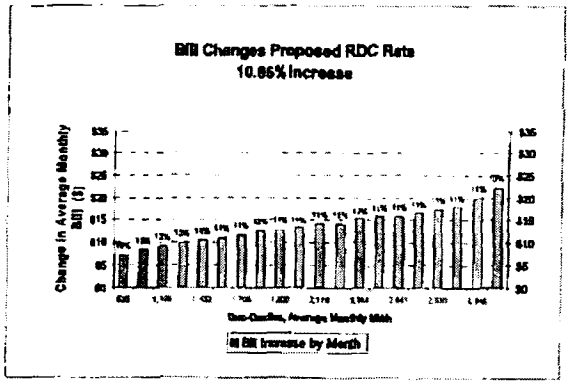


	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		Energy Charge per kWh All Year	Summer	Winter
4 Filed - Proposed Rate	$3.00	$3.00			All kWh	$0.08520	$0.07772
Customer Charge, Seasonal Energy, No Declining Block		+Facilities					
Flat Facilities Charge			$5.00				
				Water Heating Credit	-$4.00		
4 Adjusted - IR 3-2 Rate	$3.00	$3.00			All kWh	$0.08582	$0.07828
Customer Charge, Seasonal Energy, No Declining Block		+Facilities					
Flat Facilities Charge			$5.00				
				Water Heating Credit	-$4.00		

Residential Demand Control (RDC)

3,815 RDC customers, 191 per a decile

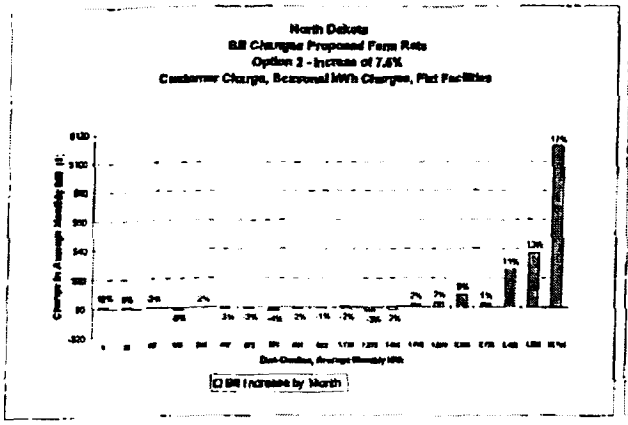


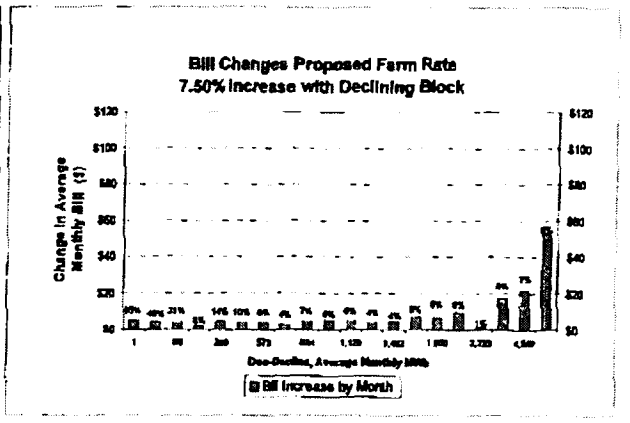


		Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month		Charge per kWh Summer	Winter	Demand Charge per kW per mo. Summer	Winter
Filed								Winter Ratchet	
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$9.38	Customer + Facilities Charge		All kWh	$0.04867	$0.04834	$5.88	$2.78
				Fixed Facilities $8.00					
				$8.00					
								Winter Ratchet	
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$9.38	Customer + Facilities Charge		All kWh	$0.04700	$0.04745	$5.82	$2.68
				Fixed Facilities $8.00					
				$8.00					

Farm Service

1,049 customers, 52 per a decile

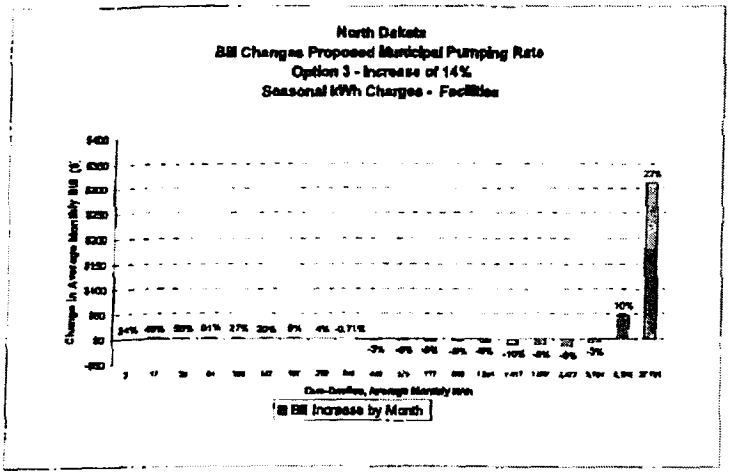


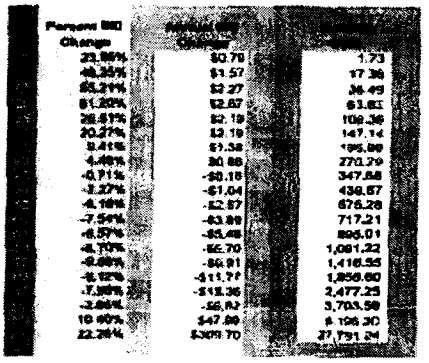


	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per kVA of Transformer	Energy per kWh Summer	Winter	All Year
2 Filed Proposed Rate				3-Phase Surcharge per Mo.			
No Declining Block Seasonal Energy Customer Charge Facilities for 3ph	$8.00	Cust + Fac	Overhead <25 kVA	$4.81	$0.07327	$0.06684	All Energy
			25 kVA or more	$5.81			
			Underground <25 kVA	$13.42			
			25 kVA or more	$21.56			
2 Adjusted Rate				3-Phase Surcharge per Mo.			Energy
Declining Block Seasonal Energy Customer Charge Facilities for 3ph	$12.00	Cust + Fac	Overhead <25 kVA	$3.57	$0.07763	$0.07080	first 1 000
			25 kVA or more	$3.93	$0.06597	$0.06018	Excess
			Underground <25 kVA	$9.39			
			25 kVA or more	$10.78			

Municipal Pumping (OPA)

575 customers, 29 per duo-decile





	Customer $ per month	Minimum Bill $ per month	Facilities Charge $ per month	Summer	Winter	All Year
				$ per kWh per month		
Current Rate	no	$3.30 per metering pt.	na		1st 2500:	$0.07152
					Next 1500:	$0.05832
					Excess	$0.04768
Rate 3 Seasonal Energy, Facilities Charge Filed - Proposed Rate						
Secondary	$4.00	Cust + Fac	$4.00	$0.06523	$0.05950	all Energy
Primary	$4.00	Cust + Fac	$2.58	$0.06484	$0.05922	all Energy

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of Otter Tail Power Company,
For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-08-862

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.

April 2009

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Introduction

Q. State your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14TH Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of 12 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 38-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Subject and Purpose of Testimony

Q. What is the subject of your testimony?

A. This case involves a filing by Otter Tail Power Company ("OTP") for authority to increase its rates by $6.1 million or 5.14 percent.[1] My testimony addresses the increase.

Q. What is the purpose of your testimony?

A. I have reviewed the Company's filing and based upon my findings and based on my review and analysis I have identified several monetary and non-monetary adjustments that should be made to the Company's filed request The monetary adjustments, which also incorporate a stipulated 8.62 percent rate of return, would reduce OTP's increase from $6.1 million to a $4.9 million increase.

Prior Experience

Q. Do you have any specific experience in the public utility field?

A. Yes, I have been in the field of public utility regulation since the late 1970's. My testimony has addressed numerous revenue requirement issues. Furthermore, I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject

[1] Brause Direct, p.2.

before the regulatory commissions of almost every state in the country.

Summary of OTP's Filing

Q. Summarize the Company's filing in this case.

A. OTP's policy witness, Mr. Brause, proposes a $6.1 million or 5.14 percent rate increase.[2] The Company's revenue requirement witness, Mr. Beithon elaborates that, "Since OTP last set its rates 24 years ago ... two primary drivers have created a need for a rate increase. ... The most significant increases driving the revenue requirement are: a 130 percent increase in North Dakota non-fuel operating and maintenance costs, which is a 5.40 percent increase using a simple average over 24 years; and a 151 percent increase in North Dakota fuel and purchased power costs, a portion of which are not currently recovered through the Fuel Clause Adjustment (FCA).[3] The Company's Notice summarizes the need for the rate increase as "The revenue deficiency is largely a result of increases in rate base and investment-related costs driven by the Company's additional investments in generation and transmission infrastructure since the last general rate application, which employed a 1983 test year."[4]

General Comments

Q. Do you have any general comments regarding OTP's requested increase?

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[2] Id.
[3] Beithon Direct, page 3.
[4] Notice, page 2.

A. Yes, in my opinion, a 5.14 percent increase after 24 years reflects a good track record, however, this rate case comes at a time when energy, gasoline and food prices are sharply increasing and the national economy is in a severe recession. Consequently, this is no time to increase ratepayers' bills for unnecessary policy changes and overstated non-cash costs. In fact, it is a time to potentially reconsider prior policies that increased customer rates merely based on theoretical accounting issues rather than core operating and maintenance cost issues. Although I do not advocate the adoption of cash-basis accounting, I do recommend recognition of cash realities when arguments such as intergenerational equity are raised as an issue to extract cash payments from ratepayers for non-cash costs.

Q. Have you investigated the Company's rate request?

A. Yes, my assistant and I read the Company's filing and propounded numerous data requests related to the Company's rate request. North Dakota Public Service Commission staff member Mr. Diller also propounded several data requests. We have reviewed those responses and conducted independent analyses as a basis for my testimony.

Depreciation

Q. Is depreciation an important aspect of this case?

A. Yes, it is. Ms. Brutlag identifies several adjustments to depreciation expense netting to a $560 thousand increase to a non-cash expense. I disagree with almost all of Ms. Brutlag's depreciation adjustments.

Q. Are there any general principles relating to depreciation that you wish to explicitly identify and address?

A. Yes, there are several. First, depreciation rates are largely set based on forecasts of future costs of removal that are highly suspect under the best of circumstances. There is great uncertainty caused by the fact that these costs will not be incurred until the plant is removed from service. The expected remaining life of the plant is a forecast, the accuracy of which will not be known until the plant is removed years or decades from now. The cost of removing that plant when the remaining life actually ends is a similar forecast of costs from far off in the future.

Typically rate cases involve substantial differences of opinion over the appropriateness of forecasts of costs that will be incurred only a year or two from now. It is hard to imagine that forecasts of removal costs that will be incurred many years after the test year could be any more accurate than the forecasts of costs that will actually arise during this rate case cycle. It does not increase the comfort in these forecasts when the amount a utility claims to have retired in the past represents a very small proportion of the total plant in service today.

Second, the terms "matching" and "intergenerational equity" (or inequity) often arise in discussions of utility depreciation practices and rates. To most accountants "matching" refers to matching revenues to the periods they are earned and costs to the periods in which they are incurred. Company

witnesses usually point to the matching principle as a rationale for adopting their proposed depreciation rates. Unfortunately, the inappropriate interpretation of matching does not justify charging current ratepayers for un-incurred future inflation to money not yet spent; yet, that is precisely what OTP proposes.

Intergenerational equity is similar to matching, as it encourages the Commission to assign costs of providing utility service to the same "generation" of ratepayers that benefited from that utility service. In depreciation discussions, intergenerational equity means that the customers who took service while a plant was in service pay the costs associated with that plant, including the cost of removing the plant from service when it reaches the end of its useful life. Assume a piece of equipment will be in service for ten years. Intergenerational equity is achieved if the total costs associated with that plant, including removal costs at the end of its life, are collected from ratepayers during the decade the plant is in service, rather than from those taking service before or after that decade.

For purposes of assessing an intergenerational equity argument, then, the Commission needs to know what "generation" the party has in mind. The test year for a rate case, or even the entire period covered by the authorized rates could be viewed as a "generation." A cost recovery pattern that appears to achieve intergenerational equity from the perspective of a ten-year "generation" of utility ratepayers (that is, those taking service while a particular

piece of equipment is in service) may not be equitable when viewed from the perspective of customers who take service early during that generation, yet bear costs that will not arise until much later in the ten-year period.

A third important concept is "straight-line recovery." The concept begs the question "straight-line of what?" To illustrate, assume that the Commission adopts a forecast saying OTP will need to collect $10,000 between 2009 and 2018 to cover the net salvage costs for plant it expects to retire from service in 2018. OTP contends that straight-line recovery must be achieved in nominal dollar amounts, that is, by collecting $1,000 per year for ten years. The Commission should use "real" dollars (that is, inflation-adjusted dollars) to achieve straight-line recovery. The same amount in real dollars is recovered in each of the ten years, but the nominal dollars vary to match inflation for each year (and are paid in dollars subject to that same level of inflation). At the end of the ten-year period, the same amount of nominal dollars is recovered under each of the two approaches. So any assertion that an approach achieves "straight-line recovery" needs to be greeted with the inquiry "in terms of nominal or real dollars?"

Q. Please discuss you specific disagreements with M's. Brutlag's depreciation proposals.

A. First, I disagree with Ms. Brutlag's proposal to allocate accumulated depreciation and depreciation expense to North Dakota rather than directly assigning depreciation as has been the past practice. OTP has been using

depreciation rates approved by the Minnesota Commission, but at one point, North Dakota had its own depreciation rates. For reasons I will discuss below, I recommend that North Dakota discontinue blanket approval of Minnesota depreciation rates and adopt its own North Dakota depreciation rates once again. There is no need to discontinue the current practice of directly assigning depreciation. I also disagree with Ms. Brutlag's proposal to increase depreciation expense by $12,095 for depreciation rate changes occurring after the end of 2007. This adjustment reflects nothing more than a decision by the Minnesota Commission to increase North Dakota service rates. I have also reduced M's. Brutlag's proposed depreciation rates, to eliminate the future inflation incorporated into those depreciation rates.

New Depreciation-Related Information

Q. Have recent accounting pronouncements revealed any new information relating to depreciation?

A. Yes, recent accounting pronouncements reveal that OTP's prior recognition of future cost of removal in depreciation rates has resulted in significant liabilities to ratepayers.

Q. Do you have any preliminary comments concerning this issue?

A. Yes, it is my understanding that ""The parties have tentatively settled this issue and are working on a final settlement document. As agreed, we are omitting discussions on this issue unless a final settlement cannot be reached or the Commission does not accept the proposed settlement. In the event the

settlement is not finalized or accepted for any reason, the parties have agreed LIG will be allowed to file testimony on this issue within five business days of such a determination."

Q. What is the genesis of this new information?

A. The genesis of the new information is the Financial Accounting Standards Board's ("FASB") 2002 Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") which addresses asset retirement obligations (AROs) associated with long-lived plant.[5]

SFAS No. 143's focus is legal obligations to incur a cost when an asset is retired – legal asset retirement obligations ("legal AROs"). SFAS No. 143 considers such obligations to be a component of the original cost of the asset. It requires capitalization and depreciation of the discounted fair value of the estimated asset retirement cost over the asset's life.

SFAS No. 143 also identified a significant regulatory liability resulting from public utilities' past inclusion of excessive future cost of removal and dismantlement factors in depreciation rates. The Federal Energy Regulatory Commission ("FERC") identified these amounts as "non-legal" asset retirement obligations, meaning that the utilities do not have actual legal obligations and liabilities to incur these costs in the future.[6] SFAS No. 143 requires reporting

[5] FERC Order No. 631 is that agency's implementation of SFAS No. 143 for regulatory purposes for utility operations subject to that agency's jurisdiction.
[6] FERC Order No. 631, para. 36.

of non-legal AROs as regulatory liabilities to ratepayers - if the requirements of SFAS 71 are met.[7]

Q. What conditions create a regulatory liability using GAAP?

A. SFAS 71, ¶11, provides that a regulator's rate actions impose a liability on the utility to its customers (regulatory liability) if the regulator provides "current rates intended to recover cost expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts."[8] For Commission-regulated utilities, this "understanding" has been implicit. Nevertheless, it is sufficiently clear to OTP to warrant creation of the regulatory liability for GAAP financial reporting purposes. Now that SFAS No. 143 has identified the amounts, this Commission should recognize them as the regulatory liabilities they are.

Q. Does OTP have any regulatory liabilities relating to non-legal AROs?

A. Yes, OTP reports a $57.8 million regulatory liability in compliance with SFAS No. 143 in its December 31, 2007 Form 10-K Report.[9] North Dakota's portion of the regulatory liability is $22.9 million.[10]

Q. What is the nature of this regulatory liability?

A. This liability consists of the cost of removal money OTP collected from ratepayers over and above its actual removal cost expenditures.

Q. What do you recommend?

---

[7] SFAS No. 143, paragraph B.73.
[8] SFAS No. 71, ¶11 and 11(b).
[9] December 31, 2007 10-K Report, p. 124.
[10] 39.61% per response to ND 02-212

A. I have three recommendations:

1. This Commission should specifically recognize, on the record, the $22.9 million as a regulatory liability for reporting and ratemaking purposes in North Dakota. It should require OTP to transfer this amount from the North Dakota depreciation reserve to account 254-other regulatory liabilities.
2. This Commission should require OTP to file a North Dakota specific depreciation study.
3. The Commission should also instruct OTP to use the present value approach if it includes future removal and dismantling costs in its calculation of depreciation rates.

Q. Why is it necessary for the Commission to recognize a regulatory liability for the non-legal cost of removal and dismantlement amounts?

A. Although the FERC has recognized and required isolation of the amount within the utility's accounting system, FERC did not require reporting the amount in FERC Form 1. FERC also failed to require reporting them as regulatory liabilities. FERC deferred these decisions to the states, which are the primary ratemaking bodies. Consequently, while FERC Order No. 631 implies a new transparency by requiring identification of the amounts and maintenance of separate subsidiary records for regulatory analysis and rate setting purposes, it did not specifically recognize a regulatory liability for non-legal AROs. The

$22.9 million North Dakota amount is clearly not identifiable in this rate case other than through my testimony.

As a result, nothing holds OTP specifically accountable for these excess collections, even though the public accounting profession and the Securities and Exchange Commission recognize that they are regulatory liabilities and that the PSC implicitly holds OTP accountable.

Regardless of the implied transparency provided by FERC's new requirements, OTP does not even identify or mention these requirements or the issue in its rate case filing. This is an intolerable situation. The accountability must be explicit, and the Commission must establish that accountability.

My experience shows that it is unlikely that all of the amounts collected will be spent for future cost of removal. Nevertheless, even if it was highly probable that OTP might spend all this money for future cost of removal, it is fair and reasonable for the Commission to recognize the ratepayers' claims on these monies until actually spent on their intended purpose. Unless they are explicitly identified as "subject to refund," there is an ongoing and unnecessary risk that they are merely hidden potential income to OTP.

It is critical that the Commission require OTP to explicitly identify and report this regulatory liability and all related activity in all future reports, rate cases and depreciation studies that it files with the Commission. The Commission should require prominent disclosure of its explicit recognition of

this amount as an intrastate regulatory liability in OTP's future FERC Form 1 reports to ensure sufficient recognition of and transparency concerning these amounts. Without a requirement for separate identification and reporting of these amounts, they are hidden from the ratemaking process and regulatory scrutiny in North Dakota.

Q. What is wrong with continuing to record the regulatory liability as accumulated depreciation?

A. OTP and all utilities consider accumulated depreciation to represent the measure of their capital that they have recovered from their ratepayers. As simplistic as it sounds, *utilities consider any amount in accumulated depreciation to be "their money" even if they collected it for a fictitious future cost.* OTP specifically states that is the "Company's money" in response to ND 02-218 i.

Q. Does OTP agree that its collections for non-legal AROs result in a regulatory liability?

A. A. No. OTP emphatically denies that its $57.8 million of excess collections for non-legal AROs constitute a regulatory liability, even though it reports it as such.[11]

Q. Why does OTP take this position?

A. OTP knows that if regulation changes, it will transfer the unspent money to its equity account rather than returning it to ratepayers.

[11] Response to ND 02-218.

The Edison Electric Institute and several individual utilities fought hard to avoid having either the FASB or FERC require the identification and reporting of the regulatory liability that I have just described.

If OTP were to be deregulated, or if regulation were to change from "cost-based" to some form of alternative "price-based" regulation, history tells us the Company would have every interest in immediately transferring its $57.8 million regulatory liability into its GAAP income. This amount could well disappear from the scene unless the Commission protects it on behalf of ratepayers. Therefore, this amount must be specifically designated as a regulatory liability for ratemaking purposes.

Q. Why do you believe that OTP would transfer its $57.8 million non-legal regulatory liability into GAAP income?

A. It will transfer the regulatory liability into GAAP income because that is what GAAP requires. If deregulated, or if regulation changes significantly, the provisions of SFAS No. 71 will no longer apply. The regulatory liability amount will flow immediately and explicitly to GAAP income, because SFAS No. 143 requires it to flow to income if it is not payable to ratepayers. This is what some electric utilities did when their production plants were deregulated, and this is what OTP warns it will do in its 2007 10-K Report.

Q. Do you have any credible evidence of such treatment in the past?

A. Yes, American Electric Power had several of its production plants deregulated. It immediately transferred $473 million from accumulated depreciation into income relating to those deregulated plants.[12]

In another example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[13]

This means that TEP transferred non-legal AROs into income.

For its regulated operations, which include the transmission and distribution portions of its business, TEP continued to apply SFAS 71. As a result, TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability.

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[14]

However, TEP also reported:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and

[12] AEP 2003 Annual Report to Shareholders, page 69.
[13] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.
[14] Id., page K-60.

its regulatory liabilities as income on its income statement.[15]

The term "write off" is a euphemism for transferring the money to income.

Q. Is TEP aware that you have used the quotation above to make the point that given the chance a utility will transfer the regulatory liability to income?

A. Yes, in November 2005, the Public Utilities Fortnightly published an article I wrote concerning the issues at hand in this proceeding. The article included the quotation from TEP's 2004 10-K Report. Subsequently, Karen G. Kissinger, TEP's Vice President, Controller & Chief Compliance Officer responded to my article.[16] Ms. Kissinger leveled several attacks against my logic, but her last sentence corroborated the risk to ratepayers that I identified in the article. Ms. Kissinger finished her letter saying: "Ratepayers are not entitled to a refund of costs recognized to provide services they have already received."[17] That means that TEP believes that its ratepayers should pay it money in advance for future costs of removal, with no expectation of a refund or future rate decrease should TEP not use the funds for their intended purpose – in that event, they belong to TEP. OTP's ratepayers are subject to the same risks.

Q. Have any other industries transferred non-legal ARO amounts into income?

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[15] Id. (Emphasis added.)
[16] Id., page 12. Public Utilities Fortnightly, Letters to the Editor, April 2006, page 10.
[17] Id.

A. Yes, while still regulated, the telephone industry collected substantial amounts of future cost of removal from its ratepayers through depreciation, just as OTP wants to continue doing. Upon deregulation and the adoption of SFAS No. 143, the major telephone companies transferred $11.5 **billion** from accumulated depreciation into their net income.[18]

Q. Can you provide any definitive additional evidence that OTP will transfer the money in the future?

A. Yes, the U.S. accounting profession is presently moving towards the adoption of International Financial Reporting Standards ("IFRS"). Upon adoption of IFRS, the regulatory liability will disappear into equity.[19]

Q. What should the Commission do with the cost of removal regulatory liability on a going-forward basis?

A. There are a number of alternatives to the treatment of the regulatory liability on a going-forward basis. The Commission could require continued maintenance as a permanent rate base offset representing customer-provided capital, or amortization back to ratepayers over some specified amortization period. I prefer an amortization, because I do not believe OTP will ever spend all of this money on future cost of removal, and as long as the money remains in the Company's hands, it will do whatever it can to convert the regulatory liability to income.

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[18] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See SBC, Verizon, Qwest, BellSouth and Sprint's 2003 10K Reports and 2003 Annual Reports to Shareholders.

[19] See Ready for IFRS?, *Public Utilities Fortnightly*, January 2009 and Fixing Depreciation Accounting, *Public Utilities Fortnightly*, October 2008.

Q. What amortization period do you recommend?

A. I recommend a 10-year amortization period.

OTP's Going-Forward Cost Of Removal Proposals

Q. Please explain what is meant by "cost of removal."

A. The cost of providing utility service includes not only the costs of installing and operating utility plant, but also removing that plant where appropriate at the end of its useful life. Therefore, one of the components of a public utility depreciation rate is a current estimate of future cost of removal (or negative net salvage).

This estimate is typically expressed as a ratio (derived from historical data), that is applied to the current plant balance to provide an estimate of the future cost of removal. This future cost is, in turn, charged to depreciation expense on a straight-line basis over the remaining life of the plant, just as the depreciation of plant investment is charged to expense. A cost of removal ratio increases the overall depreciable cost base because it allocates a portion of the estimated future removal cost to each year of the asset's service life. This process is, by definition, accrual accounting.

Q. Do you object to accrual accounting?

A. No, I do not object to accrual accounting if properly applied.

Q. If you are not raising any objection to the general process of forecasting future costs of removal or net salvage, what does your testimony address and how is it different than what OTP proposes?

A. My testimony focuses on providing the Commission with information it needs to address the inflation issue. To that end, my discussion addresses accrual accounting, matching and intergenerational equity principles. I provide a simple and straight-forward example demonstrating that the present value approach is the approach most consistent with these principles because it properly matches inflation expense to the periods incurred and eliminates the intergenerational inequity inherent in OTP's approach. I do not propose any variation on "expensing" or normalizing removal costs. Accepting OTP's future cost of removal proposals at face value, I merely express them at their present value so current ratepayers will not be charged for future inflation that has not been incurred.

In other words, for plant in service today that will likely be removed from service twenty years from now, both the present value approach and OTP's approach would recover the same total amounts. The present value approach would achieve the same straight-line pattern as OTP's approach for recovery of the original plant investment, and for recovery of the inflation-adjusted amount for the net salvage costs that will be incurred in 2029. The only difference is the cost recovery pattern for the future inflation costs; the present value approach would have the annual amounts increase during the twenty-year period to reflect the effects of inflation (and permit OTP customers to pay in inflated dollars), while OTP would allocate the future inflation costs on a

straight-line basis, an outcome that assigns a disproportionate share of those costs to current ratepayers.

Q. Are you challenging any of OTP's proposed lives?

A. No, I am not challenging any of OTP's proposed lives. I think it is more important at this juncture to focus the Commission's attention on how OTP's approach treats future inflation costs. I will show how a simple modification to this treatment can achieve the proper and far more equitable outcome that is consistent with the matching principle, minimizes intergenerational inequity, and has the added advantage of lowering the utility's depreciation rates.

Q. How did OTP arrive at his net salvage or future cost of removal proposals?

A. OTP conducted a "traditional" historical net salvage analysis to estimate future net salvage ratios for each account.

Q. Why do you object to OTP's traditional approach?

A. OTP's approach is front-loaded in its treatment of future inflation costs. It increases the current estimate of future costs of removal for a substantial amount of future inflation. In other words, OTP's approach charges current ratepayers on an undiscounted basis for future inflation. I disagree with OTP's approach from an accounting standpoint as well as from a ratemaking standpoint. Accrual accounting consists of matching costs to the periods in which they are incurred. OTP's approach fails that fundamental test by front-

loading future inflation. This defect is why GAAP specifically precludes his approach.

Q. Why does OTP's approach result in inflated future cost of removal estimates?

A. OTP bases his approach on the relationship of current cost of removal expenditures in today's dollars versus the original cost of the plant being retired, calculating a ratio of current cost of removal (in today's dollars) to original cost of plant (in historical dollars). A substantial part of the current cost of removal represents past inflation experienced during the period (often decades) between when the plant was first put in service and when the removal costs were incurred. OTP then applies that ratio to today's plant balances to project the future cost of removal. In this way, the calculation extrapolates into the future all of the past inflation rather than the small portion actually experienced during the test year 2007.

Accrual Accounting

Q. What is accrual accounting?

A. Accrual accounting recognizes or matches revenue to the periods earned and expenses to the periods incurred. Accrual accounting is the foundation of generally accepted accounting principles ("GAAP"). The directives issued by the Financial Accounting Standards Board ("FASB"), such as SFAS No. 143 and FIN 47 set forth in GAAP.

Q. What is cash basis accounting?

A. Cash basis accounting recognizes revenues and expenses when received or disbursed rather than when earned or incurred.

Q. Does OTP's approach constitute accrual accounting?

A. I do not believe it does, at least to the extent it charges current ratepayers the costs of inflation that may not be incurred for years or even decades. An approach more consistent with accrual accounting would match those future inflation costs to the ratepayers taking utility service at the time the inflation is incurred. OTP's approach does not match inflation costs to the periods incurred.

Q. Do the relatively recent pronouncements of the Financial Accounting Standards Board provide any useful guidance on these questions?

A. I believe they do, even if the questions are arising here in a ratemaking proceeding and the FASB pronouncements apply most directly to financial reporting requirements. But the underlying principles of achieving appropriate "matching" through accrual accounting do not change whether they arise in a ratemaking or financial reporting setting.

OTP is no doubt familiar with the accounting prescribed in SFAS No. 143 and FIN 47, which constitute GAAP. SFAS No. 143 was adopted to establish accounting standards for recognition and measurement of a liability for an asset retirement obligation and any associated asset retirement cost. (SFAS No. 143, ¶ 1.) SFAS 143 provides that where there are no quoted market prices to use for such estimating purposes, a "present value" technique

is often the best available substitute. (SFAS No. 143, ¶ 8.) This present value technique prescribed in SFAS 143 directs the discounting of the estimated future cash flows using "credit-adjusted risk-free rate."

OTP may argue that the Commission should not rely on SFAS No. 143 or FIN 47 for purposes of deciding ratemaking issues. However, for purposes of deciding what approach is most consistent with principles of accrual accounting, I submit there is no better source than FAS 143 and the other FASB pronouncements that are, after all, the embodiment of GAAP. And, under FAS 143 companies are not required to report the absolute future value of removal costs, but rather a "present value" of those future costs. For financial reporting purposes, this better enables investors to assess a company's future asset retirement obligations. For ratemaking, it serves a different purpose. Using a present value calculation of the future costs of removal ensures that the future removal cost expenditure is measured in a way that achieves a fair revenue requirement to charge customers during an accounting period. The present value approach treats OTP's study year as the relevant "accounting period" OTP's testimony refers to.

It is important to be clear about this. In other cases in which I have been involved, utilities have characterized the present value approach as seeking to have the Commission adopt SFAS 143 for ratemaking purposes when, in fact, the utility only adopted SFAS S143 for financial reporting purposes.

I am not asking the Commission to adopt SFAS 143 for ratemaking purposes. However, for the purpose of developing an appropriate estimate of the amount of future removal costs to include in today's rates, the underlying principle is consistent with accrual accounting as set forth in GAAP (of which SFAS 143 is a part); whether the estimate is to be used for financial reporting purposes or for establishing a reasonable rate under cost-of-service ratemaking. The amount that should be charged to the "accounting period" is an appropriate share of the present value of the future obligation. The Commission may choose to use something other than the "credit-adjusted risk-free rate" described in SFAS No. 143 for calculating the present value of the future obligation. For example, I recommend the Handy Whitman indices as the basis to make the adjustment. But the underlying principle of accrual accounting and ratemaking remains – future cost of removal is properly measured and matched to the period incurred. In ratemaking, the accounting period is the current year, not the remaining life of the plant.

Q. Can you demonstrate that using the present value approach constitutes accrual accounting and that OTP's approach does not constitute accrual accounting?

A. Yes. Exhibit___ (MJM-1) is a chart I designed to demonstrate those facts. It is a simple single asset example comparing OTP's approach to collecting future inflation versus the present value accrual approach. The example assumes the present value to remove a single structure is $20,000, but that

will increase over the structures' 20-year life to $53,066 at a 5 percent inflation rate. As you can see, both OTP's approach and the present value approach accumulate the same $53,066 total amount for future removal costs by the end of the asset's life. The difference is the rate of collection for future inflation costs. The present value approach matches inflation to the periods incurred. OTP's approach front-loads future inflation costs into current periods, and by doing so overcharges ratepayers in the early years and undercharges ratepayers in the later years. This flies in the face of the "intergenerational equity" and accrual accounting concepts; it stands them on their heads.

Q. Is this example intended to show rate base effects?

A. No, the example demonstrates that accrual accounting matches inflation to the periods incurred. Rate base is irrelevant to that demonstration.

Q. Is there any economic rationale that supports matching future inflation to the periods incurred?

A. Yes, the inflation-related portion of the future removal cost will be paid for with cheaper dollars in future years. In terms of nominal dollars, the amount to be paid appears to be higher, but in real (that is, inflation-adjusted) dollars, the same amount is paid now and in the future, all else being equal. In other words, if OTP were to retire and remove all of its assets today, it would incur the present value of OTP's same future cost of removal estimates. When it comes to future inflation costs, "straight-line" cost allocation should be measured in real dollars, not nominal dollars.

Q. Is OTP's approach required under the Uniform System of Accounts ("USOA")?

A. No, nothing in the USOA requires depreciation rates to be based on inflated future costs, or to collect from today's ratepayers the costs of inflation that will not be experienced for years or even decades to come.

Consolidated Taxes

Q. Do you have any other examples of OTP collecting funds in excess of its actual costs?

A. Yes, OTP is a participant in a consolidated federal income tax return. These arrangements can result in the ratepayers of regulated entities subsidizing losses of unregulated affiliates. In other public utility cases, I have read tax allocation agreements between the parties to consolidated tax returns. On more than one occasion, I have seen words requiring a pass through of taxes collected from a regulated entity to the parent and from there to the loss affiliates. In fact, that is precisely what is called for in OTP's tax sharing agreement.[20]

Q. Has the Commission employed the stand-alone approach in the past?

A. Yes, it has. However, given the experience with energy, gasoline and food price increases, I recommend that the Commission revisit the issue. In a period of dwindling resources and corresponding upward price spirals, the Commission should at least know the magnitude of the consolidated tax

[20] See response to ND 02-58.

subsidy and reconsider whether captive ratepayers should be required to pay anything more than actual taxes. The Commission should place OTP on alert in this proceeding that it intends to revisit the consolidated tax issue in the next rate case.

Summary of Snavely King Adjustments

Q. Do you have a summary of your individual adjustments to the Company's filed revenue requirement?

A. Yes, Exhibit___ (MJM-2) summarizes the adjustments. It also incorporates a stipulated 8.62 percent rate of return. The adjusted revenue requirement is $.645 million less than OTP's.

Adjustment No. 1 – Implement Stipulated Rate of Return

Q. Please explain each adjustment.

A. Adjustment No. 1 implements the 8.62 percent rate of return to which the parties have stipulated.

Adjustment No. 2 – Reverse Allocation of Depreciation

Q. Please explain Adjustment No. 2.

A. Adjustment No. 2 reverses Ms. Brutlag's proposal to allocate, rather than directly assign depreciation to North Dakota.

Adjustment No. 3 – Reverse Depreciation Increase Using 2008 Depreciation Rates

Q. Please explain Adjustment No. 3.

A. Adjustment No. 3 reverses the $12,095 depreciation increase Ms. Brutlag proposes to reflect the 2008 Minnesota depreciation rates.

Adjustment No. 4 – Reverse Depreciation Decrease Using Brutlag Proposed Depreciation Rates

Q. Please explain Adjustment No. 4.

A. Adjustment No. 4 reverses the depreciation decrease Ms. Brutlag proposes based on a new study that is yet to be approved by the Minnesota Commission. Even with a decrease these depreciation rates are excessive due to their inclusion of future inflation in the cost of removal estimates.

Adjustment No. 5 – Implement North Dakota Staff Depreciation Rates

Q. Please explain Adjustment No. 5.

A. Adjustment No. 5 implements the North Dakota Staff's recommended depreciation rates. They accept Ms. Brutlag's parameter proposals, but eliminate the future inflation expense from the cost of removal estimates included in the rate calculations.

Adjustment No. 6 – Reduce Depreciation Expense for New Plant

Q. Please explain Adjustment No. 6.

A. Adjustment No. 6 reduces Ms. Brutlag's proposed depreciation expense relating to new plant to conform to the North Dakota Staff's recommended depreciation rates.

Adjustment No. 7 – Charitable Donations

Q. Please explain Adjustment No. 7.

A. Adjustment No. 7 removes charitable donations from the Company's revenue requirement claim. This adjustment results in an $114,816 reduction to the revenue requirement.

Q. Why have you made this adjustment?

A. Otter Tail included in its revenue requirement certain charitable donations. These donations are not necessary for the provision of safe, reliable and efficient electric and natural gas service. While it is commendable that the Company is involved in civic and charitable activities, ratepayers should not be expected to finance those activities. As such, I have removed these donations.

Adjustment No. 8 – STB Litigation Expense

Q. Please explain Adjustment No. 8.

A. Adjustment No. 8 removes $40,973 related to litigation before the Surface Transportation Board from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Included in Otter Tail's test year revenue requirement is $40,973 in expense related past litigation before the STB. Because this litigation effort is finished, any expenses related to it will not be ongoing. Therefore, I have removed the $40,973 from the revenue requirement.

Adjustment No. 9 – Economic Development Expense

Q. Please explain Adjustment No. 9.

A. Adjustment No. 9 removes $108,539 related to economic development from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has proposed increasing the amount included in rates for economic development activities to $500,000. The current annual amount included in rates is $315,557, which was approved during the 1988/1989 time frame.[21] According to Company witness Ms. Brutlag, Otter Tail has averaged $513,698 per year since the inception of the program.[22] While this may be true, the amount is skewed by a $1.3 million expenditure in 1995. A more recent calculation using 2004 through 2008 amounts indicates the Company averages $391,461 in economic development expense.

Otter Tail's economic development activities appear to provide a genuine service to the community, including job creation in many cases.[23] This is particularly important in today's economic environment. However, the rate payers being asked to pay for these activities are also victims of the current economy and should not be asked to pay higher rates in order to finance Otter Tail's community involvement.

Because the previous amount was set in 1988/1989, I have updated the amount to Otter Tail's most recent five-year average of $391,461. This results in a $108,539 decrease to the revenue requirement.[24]

Adjustment No. 10 – Employee Awards

Q. Please explain Adjustment No. 10.

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[21] Brutlag, pp. 18-19.
[22] Exhibit___ (BCB-1), Schedule 2.
[23] See Brutlag, p. 19 and response to ND 02-009.
[24] $500,000 included in Company's claim less $391,461 recommended amount.

A. Adjustment No. 10 removes $76,089 related to employee awards, gifts, dinners and similar activities from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. In its response to ND 02-126, the Company provided the year 2007 amounts for employee gifts, luncheons, dinners, picnics and awards. The total amount was $85,989. This amount includes $36,456 in annual employee service awards and $15,522 in "token gifts given to each employee attending annual executive forum meetings."[25] A review of the invoices provided shows that the awards purchased ranged from hunting knives to flat screen televisions.[26] While I understand that some companies include these types of activities for employees as morale boosters, I do not believe the rate payers should be asked to finance them. As such, I have removed the amounts. However, of the total, $9,900 related to safety award checks.[27] I have allowed that amount to stay in the revenue requirement.

Adjustment No. 11 – Asset-Based Margins

Q. Please explain Adjustment No. 11.

A. Adjustment No. 11 eliminates asset-based margins which Mr. King recommends be flowed through the fuel clause.

Q. Why have you made this adjustment?

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[25] See response to ND 02-126, Attachment 2.
[26] Id., Attachment 1.
[27] Id, Attachment 2.

A. As I stated, Mr. King discusses this adjustment in detail in his testimony. However, I observe that the Ancillary Services Market is up and running, but it just started, consequently, it is probably too early to try and include an amount in base rates. Furthermore, if the margins are not run through the fuel clause adjustment, a perverse incentive could ensue where OTP would be better off setting aside its generating units to provide ASM services and generating ASM revenues (not included in the rate case) and purchasing power for its customers which off course are automatically ran through the FCA.

Adjustment No. 12 – Executive Incentive Pay

Q. Please explain Adjustment No. 12.

A. Adjustment No. 12 removes $150,668 related to executive incentive pay from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has included $358,248 (total company) in executive incentive pay in its revenue requirement calculation. The North Dakota portion of that amount is $150,668. I have removed the entire provision for executive incentives for several reasons. First, as I have discussed several times in my testimony, the current state of the economy should discourage the payment of any bonus plans. Notwithstanding the well-publicized actions of certain companies receiving federal assistance, many companies today are actually instituting pay cuts in order to stay viable during this time. Second, as described in the response to ND 02-102, payment of the executive incentive plan target amount

is 60 percent dependent on the achievement of financial goals (regulated return on equity and return on invested capital), which are designed to benefit shareholders, not ratepayers.[28] The remaining 40 percent is dependent on "individual performance." I do not know what areas of "individual performance" are considered, but there is no indication this is safety or service related, unlike the design of the incentive plan for non-executive employees. If Otter Tail wishes to pay its executives an incentive bonus it should be paid for by shareholders, not ratepayers.

Adjustment Nos. 13 and 14 – Reverse OPEB Transition Costs

Q. Please explain Adjustment Nos. 13 and 14.

A. Both of these adjustments relate to SFAS No. 106 costs which, in turn, are costs associated with Other Post Employment Benefits. Mr. Beithon states that "These costs are tracked in two parts – transition costs and current accrual expenses."[29]

Adjustment No. 13 is a reversal of the Company's 2006 elimination of the so-called transition obligation associated with OPEBs. OTP had apparently recorded a receivable in its prepayments account to reflect the amount it intended to charge ratepayers for the transition obligation. In reality, it appears that it had overestimated the amount it needed for OPEB costs, and in fact did not even create a funded liability for these costs, such as it has for

[28] See response to ND 02-102, Attachment 3, p. 2.
[29] Beithon page 32.

its pension obligation. Consequently, upon adoption of SFAS No. 158, it wrote-off the prepayment/receivable.

In this case, OTP proposes to create $1,678,516 of off-book income merely by crediting its retained earnings account and returning the $1,678,516 into prepayments with a corresponding $335,703 annual amortization expense obligation it would like ratepayers to pay. I reject both of those requests. OTP actually funds its OPEBs on a pay-as-you go basis, just as it has done from the very beginning. It does not maintain a cash fund for these costs. Adjustment No. 13 reverses OTP's attempt to reestablish a receivable from ratepayers for prior OPEB costs, and Adjustment No. 14 reverses OTP's amortization of the fictitious transition receivable. In my opinion, the Commission should also require OTP to begin funding its OPEB liability.

Adjustment Nos. 15 and 16 – Flow MISO Amounts Through Fuel Adjustment Change

Q. Please explain Adjustment Nos. 15 and 16.

A. Adjustment Nos. 15 and 16 reflects Staff's position that MISO costs should be flowed through the fuel adjustment charge.

Adjustment No. 17 – Reverse Non-Asset Based Margins

Q. Please explain Adjustment No. 17.

A. Adjustment No. 17 reverses OTP's proposal to include non-asset based margins in the revenue requirement.

Q. Why did you make this adjustment?

A. I made this adjustment because the Company's proposal allocates more cost from the Company's trading department than it does revenues from non-asset based margins.

Adjustment No. 18 – Reverse DSM and Energy Conservation

Q. Please explain Adjustment No. 18.

A. Adjustment No. 18 reverses OTP's DSM and Energy Conservation charges so they can be recovered through a separate rider.

Q. Does this conclude your testimony?

A. Yes, it does.

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Bedell, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

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1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

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1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

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2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

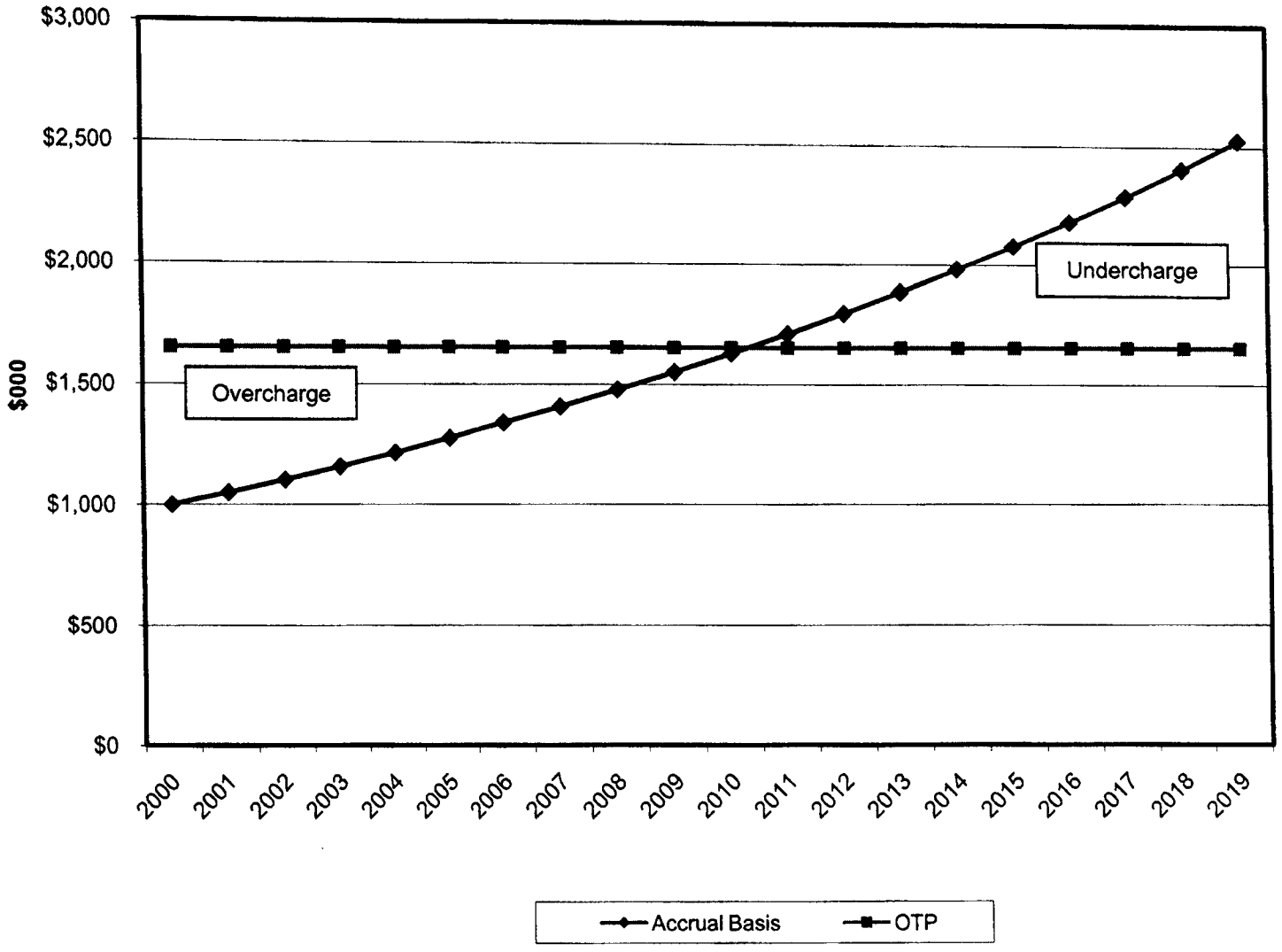
STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	34/ New Mexico Attorney General
2/ West Virginia Consumer Advocate	35/ Environmental Protection Agency Enforcement Staff
3/ Pennsylvania OCA	36/ Kentucky Attorney General
4/ Florida Office of Public Advocate	37/ North Dakota Public Service Commission
5/ Toms River Fire Commissioner's	38/ Kansas Industrial Group
6/ Iowa Office of Consumer Advocate	39/ City of Witchita
7/ D.C. People's Counsel	40/ Kansas Citizens' Utility Rate Board
8/ Maryland's People's Counsel	41/ NIPSCO Industrial Group
9/ Idaho Public Service Commission	42/ Hawaii Division of Consumer Advocacy
10/ Western Burglar and Fire Alarm	43/ Nevada Bureau of Consumer Protection
11/ U.S. Dept. of Defense	44/ GCI
12/ N.M. State Corporation Comm.	45/ Wisc. Citizens' Utility Rate Board
13/ City of Philadelphia	46/ Vermont Department of Public Service
14/ Resorts International	47/ Oklahoma Corporation Commission
15/ Woodlake Condominium Association	48/ National Assn. of State Utility Consumer Advocates
16/ Illinois Attorney General	49/ Nova Scotia Utility and Review Board
17/ Mass Coalition of Municipalities	50/ Florida Office of Public Counsel
18/ U.S. Department of Energy	51/ Maryland Public Service Commission
19/ Arizona Electric Power Corp.	52/ MCI
20/ Kansas Corporation Commission	53/ Transmission Agency of Northern California
21/ Public Service Comm. – Nevada	54/ Florida Industrial Power Users Group
22/ SC Dept. of Consumer Affairs	55/ Sierra Club
23/ Georgia Public Service Comm.	56/ Our Children's Earth Foundation
24/ Delaware Public Service Comm.	57/ National Parks Conservation Association, Inc.
25/ Conn. Ofc. Of Consumer Counsel	58/ Missouri Office of the Public Counsel
26/ Arizona Corp. Commission	59/ The Utility Reform Network
27/ AT&T	60/ Colorado Office of Consumer Counsel
28/ AT&T/MCI	61/ MD State Senator Paul G. Pinsky
29/ IN Office of Utility Consumer Counselor	62/ MD Speaker of the House Michael Busch
30/ Unitel (AT&T – Canada)	63/ Washington Office of Public Counsel
31/ Public Interest Advocacy Centre	64/ Industrial Customers of Northwestern Utilities
32/ U.S. General Services Administration	65/ Steering Committee of Cities
33/ Michigan Attorney General	66/ City of Chattanooga

Comparison of Inflation Expense Patterns



Otter Tail Power Company
Comparison of Accrual Accounting Versus OTP Treatment of Inflation

Line	Assumptions:	Year 1	
	Year 1 (2000) Data	2000	
1	Number of Structures	1	structure
2	Service Life	20	years
3	Average age of structure	0	years
4	Remaining life	20	years
5	Present Value of Disposal Cost Per Structure	$20,000	
6	Present Value of Future Disposal Costs L.1 * L5	$20,000	
7	Future inflation rate	5.00%	Assumed
8	Inflated Value of Future Disposal Costs	$ 53,065.95	
9	Original Cost of Structure	$ 100,000	
10	OTP Approach Recommendation -(L8/L9)	-53.07%	

	Straight Line Recovery of Original PV of Future Removal			Inflation to Original Cost of Future Removal				Annual Expense		
Year	Original Cost of Future Removal BOY	Depreciation Expense	Accumulated Depreciation EOY	PV of Future Cost BOY	Inflation Expense	PV of Cost EOY	Cumulative Inflation	Accrual Basis Annual Expense	OTP Annual Expense	OTP Inflation Matching
2000	$20,000	$1,000	$1,000.00	$ 20,000.00	$1,000.00	$21,000.00	$1,000.00	$2,000.00	$2,653.30	$1,653.30
2001	20,000	1,000	2,000.00	21,000.00	1,050.00	22,050.00	2,050.00	2,050.00	2,653.30	1,653.30
2002	20,000	1,000	3,000.00	22,050.00	1,102.50	23,152.50	3,152.50	2,102.50	2,653.30	1,653.30
2003	20,000	1,000	4,000.00	23,152.50	1,157.63	24,310.13	4,310.13	2,157.63	2,653.30	1,653.30
2004	20,000	1,000	5,000.00	24,310.13	1,215.51	25,525.63	5,525.63	2,215.51	2,653.30	1,653.30
2005	20,000	1,000	6,000.00	25,525.63	1,276.28	26,801.91	6,801.91	2,276.28	2,653.30	1,653.30
2006	20,000	1,000	7,000.00	26,801.91	1,340.10	28,142.01	8,142.01	2,340.10	2,653.30	1,653.30
2007	20,000	1,000	8,000.00	28,142.01	1,407.10	29,549.11	9,549.11	2,407.10	2,653.30	1,653.30
2008	20,000	1,000	9,000.00	29,549.11	1,477.46	31,026.56	11,026.56	2,477.46	2,653.30	1,653.30
2009	20,000	1,000	10,000.00	31,026.56	1,551.33	32,577.89	12,577.89	2,551.33	2,653.30	1,653.30
2010	20,000	1,000	11,000.00	32,577.89	1,628.89	34,206.79	14,206.79	2,628.89	2,653.30	1,653.30
2011	20,000	1,000	12,000.00	34,206.79	1,710.34	35,917.13	15,917.13	2,710.34	2,653.30	1,653.30
2012	20,000	1,000	13,000.00	35,917.13	1,795.86	37,712.98	17,712.98	2,795.86	2,653.30	1,653.30
2013	20,000	1,000	14,000.00	37,712.98	1,885.65	39,598.63	19,598.63	2,885.65	2,653.30	1,653.30
2014	20,000	1,000	15,000.00	39,598.63	1,979.93	41,578.56	21,578.56	2,979.93	2,653.30	1,653.30
2015	20,000	1,000	16,000.00	41,578.56	2,078.93	43,657.49	23,657.49	3,078.93	2,653.30	1,653.30
2016	20,000	1,000	17,000.00	43,657.49	2,182.87	45,840.37	25,840.37	3,182.87	2,653.30	1,653.30
2017	20,000	1,000	18,000.00	45,840.37	2,292.02	48,132.38	28,132.38	3,292.02	2,653.30	1,653.30
2018	20,000	1,000	19,000.00	48,132.38	2,406.62	50,539.00	30,539.00	3,406.62	2,653.30	1,653.30
2019	20,000	1,000	20,000.00	50,539.00	2,526.95	53,065.95	33,065.95	3,526.95	2,653.30	1,653.30
		$20,000.00			$33,065.95			$53,065.95	$53,066.00	

Comparison of Inflation Expense Patterns

Year	Accrual Basis Annual Inflation	OTP Annual Inflation
2000	$1,000.00	$1,653.30
2001	1,050.00	1,653.30
2002	1,102.50	1,653.30
2003	1,157.63	1,653.30
2004	1,215.51	1,653.30
2005	1,276.28	1,653.30
2006	1,340.10	1,653.30
2007	1,407.10	1,653.30
2008	1,477.46	1,653.30
2009	1,551.33	1,653.30
2010	1,628.89	1,653.30
2011	1,710.34	1,653.30
2012	1,795.86	1,653.30
2013	1,885.65	1,653.30
2014	1,979.93	1,653.30
2015	2,078.93	1,653.30
2016	2,182.87	1,653.30
2017	2,292.02	1,653.30
2018	2,406.62	1,653.30
2019	2,526.95	1,653.30

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	SK Recommended 2007 Test Year	Difference
		a	b	c=b-a
1	Average Rate Base	$187,173,203	$187,745,238	$572,035
2	Operating Income (Before AFUDC)	$12,942,144	$13,185,453	$243,309
3	Allowance for Funds Used During Construction (AFUDC)	-	-	-
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$12,942,144	$13,185,453	$243,309
5	Overall Rate of Return (Line 4 / Line 1)	6.91%	7.02%	
6	Required Rate of Return	8.89%	8.62%	
7	Operating Income Requirement (Line 1 x Line 6)	$16,639,698	$16,183,640	($456,058)
8	Income Deficiency (Line 7 - Line 4)	$3,697,554	$2,998,186	($699,367)
9	Gross Revenue Conversion Factor	1.645413	1.645413	
10	Revenue Deficiency (Line 8 x Line 9)	$6,084,004	$4,933,256	($1,150,749)
11	Retail Related Revenues Under Present Rates	$118,309,177	$118,309,177	$0
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	5.14%	4.17%	

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Staff Depreciation Rates	Adj. 6 Reduce Dep Expense for New Plant	Adj. 7 Charitable Contributions	Adj. 8 STB Litigation
	OPERATING REVENUES								
1	Retail Revenue	$ 118,309,177	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	13,804,432	-	-	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ 132,113,610	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ 67,714,739	$ -	$ -	$ -	$ -	$ -	$ -	$ (40,973)
5	Transmission Expenses	4,467,061	-	-	-	-	-	-	-
6	Distribution Expenses	6,727,802	-	-	-	-	-	-	-
7	Customer Accounting Expenses	4,728,770	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	2,185,290	-	-	-	-	-	-	-
9	Sales Expenses	701,476	-	-	-	-	-	-	-
10	Administration and General Expenses	13,557,519	-	-	-	-	-	-	-
11	Charitable Contributions	114,816	-	-	-	-	-	(114,816)	-
12	Depreciation Expense	10,716,072	(268,864)	(12,095)	209,145	(1,339,694)	(54,650)	-	-
13	General Taxes	3,957,594	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ 114,871,139	$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (54,650)	$ (114,816)	$ (40,973)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 17,242,470	$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 54,650	$ 114,816	$ 40,973
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ (476,372)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	213,186	-	-	-	-	-	-	-
19	Income Taxes	4,563,512	105,462	4,744	(82,037)	525,496	21,437	45,037	16,072
20	**TOTAL INCOME TAX EXPENSE**	$ 4,300,326	$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 21,437	$ 45,037	$ 16,072
21	**NET OPERATING INCOME**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
22	Allowance for Funds Used During Construction	-	-	-				-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
24	**TOTAL RATE BASE**	187,173,203	1,053,257	12,095	(209,145)	1,339,694	54,650	-	-
25	Otter Tail Rate of Return	8.89%							
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
27	Rate Base Effect	$ (505,368)	$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,711	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413
29	Incremental Revenue Requirement	$ (831,539)	$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (46,898)	$ (114,816)	$ (40,973)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 9 Economic Development	Adj. 10 Employee Awards	Adj 11. Asset-Based Margins	Adj. 12 Mgmt Incentives	Adj. 13 Reverse OPEB Prepayments	Adj. 14 Remove OPEB Transition Costs	Adj. 15 Reverse MISO	Adj. 16 Reverse MISO Amort.
	OPERATING REVENUES								
1	Retail Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	-	-	(8,508,499)	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ -	$ -	$ (4,375,390)	$ -	$ -	$ -	$ (256,990)	$ (309,019)
5	Transmission Expenses	-	-	-	-	-	-	-	-
6	Distribution Expenses	-	-	-	-	-	-	-	-
7	Customer Accounting Expenses	-	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	-	-	-	-	-	-	-	-
9	Sales Expenses	(108,539)	-	-	-	-	-	-	-
10	Administration and General Expenses	-	(76,089)	-	(150,668)	-	-	-	-
11	Charitable Contributions	-	-	-	-	-	-	-	-
12	Depreciation Expense	-	-	-	-	-	-	-	-
13	General Taxes	-	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ (108,539)	$ (76,089)	$ (4,375,390)	$ (150,668)	$ -	$ (335,705)	$ (256,990)	$ (309,019)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 108,539	$ 76,089	$ (4,133,109)	$ 150,668	$ -	$ 335,705	$ 256,990	$ 309,019
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	-	-	-	-	-	-	-	-
19	Income Taxes	42,574	29,846	(1,621,212)	59,099	-	131,680	100,804	121,213
20	**TOTAL INCOME TAX EXPENSE**	$ 42,574	$ 29,846	$ (1,621,212)	$ 59,099	$ -	$ 131,680	$ 100,804	$ 121,213
21	**NET OPERATING INCOME**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
22	Allowance for Funds Used During Construction	-	-	-	-	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
24	**TOTAL RATE BASE**	-	-	-	-	(1,678,516)	-	-	-
25	Otter Tail Rate of Return	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
26	Stipulated Rate of Return Adjustment 1.								
27	Rate Base Effect	$ -	$ -	$ -	$ -	$ (144,688)	$ -	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413
29	Incremental Revenue Requirement	$ (108,539)	$ (76,089)	$ 4,133,109	$ (150,668)	$ (238,072)	$ (335,705)	$ (256,990)	$ (309,019)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 17 Reverse Non-Asset Based Margins	Adj. 18 Reverse Energy Efficiency	Total SK Adjustments	SK Adjusted 2007 Test Year
	OPERATING REVENUES				
1	Retail Revenue	$ -	$ -	$ -	$ 118,309,177
2	Other Electric Operating Revenue	-	-	(8,508,499)	5,295,933
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ 123,605,111
	OPERATING EXPENSES				
4	Production Expenses	$ (674,535)	$ -	$ (5,656,906)	$ 62,057,832
5	Transmission Expenses	-	-	-	4,467,061
6	Distribution Expenses	-	-	-	6,727,802
7	Customer Accounting Expenses	-	-	-	4,728,770
8	Customer Service and Information Expenses	-	(1,000,000)	(1,000,000)	1,185,290
9	Sales Expenses	-	-	(108,539)	592,937
10	Administration and General Expenses	-	-	(226,757)	13,330,762
11	Charitable Contributions	-	-	(114,816)	-
12	Depreciation Expense	-	-	(1,466,158)	9,249,914
13	General Taxes	-	-	-	3,957,594
14	**TOTAL OPERATING EXPENSES**	$ (674,535)	$ (1,000,000)	$ (8,908,882)	$ 105,962,257
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 674,535	$ 1,000,000	$ 400,383	$ 17,642,853
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	$ -	$ -	$ -	$ (476,372)
18	Deferred Income Taxes	-	-	-	213,186
19	Income Taxes	264,608	392,250	157,073	4,720,585
20	**TOTAL INCOME TAX EXPENSE**	$ 264,608	$ 392,250	$ 157,073	$ 4,457,400
21	**NET OPERATING INCOME**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
22	Allowance for Funds Used During Construction	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
24	**TOTAL RATE BASE**	-	-	572,035	187,745,238
25	Otter Tail Rate of Return				
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%		
27	Rate Base Effect	$ -	$ -	$ (456,058)	
28	Revenue Conversion Factor	1.645413	1.645413		
29	Incremental Revenue Requirement	$ (674,499)	$ (1,000,000)		

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

Line No.	Description				OtterTail % of Incremental Gross Revenues	SK % of Incremental Gross Revenues
1	Federal Income Taxes				32.73%	32.73%
2	State Income Taxes				6.50%	6.50%
3	Total Tax Percentage				39.23%	39.23%
4	Operating Income %	=	100% - 39.23%	=	60.78%	60.78%
5	Gross Revenue Conversion Factor	=	100.00% / 60.77%	=	1.645413	1.645413

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 7

REMOVE CHARITABLE CONTRIBUTIONS

Line	Description		
	Expense Adjustment		
1	Charitable contributions included in revenue requirement		$ 114,816
2	Total Expense Adjustment - Pre Tax		$ (114,816)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		45,037
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (69,779)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (114,816)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 8

REMOVE STB LITIGATION EXPENSE

Line	Description		
	Expense Adjustment		
1	STB litigation expense included in revenue requirement		$ 40,973
2	Total Expense Adjustment - Pre Tax		$ (40,973)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		16,072
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (24,901)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (40,973)

Source:
02-010(c)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 9

ADJUST ECONOMIC DEVELOPMENT EXPENSE TO FIVE-YEAR AVERAGE

Line	Description		
	Expense Adjustment		
1	Economic Development expenses included in revenue requirement		$ 500,000
2	Five-Year Average Economic Development expenses		$ 391,461
3	Total Expense Adjustment - Pre Tax		$ (108,539)
4	Tax Rate	39.23%	
5	Tax Effect (L. 3 * L. 4)		42,574
6	Adjustment - Post Tax (L. 3 + L. 5)		$ (65,965)
7	Revenue Conversion Factor		1.64541341
8	Revenue Requirement (L. 6 * L. 7)		$ (108,539)

Calculation of 5-Year Average

2004	$ 322,774
2005	397,489
2006	427,361
2007	427,508
2008	382,173
5-year Avg.	$ 391,461

Source:

Years 2004 through 2007 from Exhibit___(BCB-1), Schedule 2. Year 2008 from response to ND 02-009.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 10

REMOVE EMPLOYEE AWARDS

Line	Description		
	Expense Adjustment		
1	Total employee gifts, awards, dinners, etc. included in revenue requirement		$ 85,989
2	Less safety awards		$ (9,900)
3	Total to be excluded		$ 76,089
4	Total Expense Adjustment - Pre Tax		$ (76,089)
5	Tax Rate	39.23%	
6	Tax Effect (L. 4 * L. 5)		29,846
7	Adjustment - Post Tax (L. 4 + L. 6)		$ (46,243)
8	Revenue Conversion Factor		1.64541341
9	Revenue Requirement (L. 7 * L. 8)		$ (76,089)

Source:

See response to ND 02-126, Attachment 2.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 11

REMOVE ASSET BASED MARGINS

Line	Description		Company Proposed Amounts	Snavely King Reccomended Amounts	Total Adjustment
1	Asset-based margin - revenue		$ 8,508,499	$ -	$ (8,508,499)
2	Asset-based margin - expense		4,375,390	-	(4,375,390)
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ 4,133,109	$ -	$ (4,133,109)
4	Tax Rate	39.23%			
5	Tax Effect (L. 3 * L. 4)				(1,621,212)
6	Adjustment - Post Tax (L. 3 - L. 5)				$ 2,511,897
7	Revenue Conversion Factor				1.64541341
8	Revenue Requirement (L. 6 * L. 7)				$ 4,133,109

Source:

"4A - 2007 ND TY-15 Asset Based Margins Adj.xls"

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 12

REMOVE MANAGEMENT INCENTIVE PAY

Line	Description		Total Company	ND Allocation
	Expense Adjustment			
1	Management incentive pay included in proposal		$358,248	$ 150,668
2	SK recommended management incentive pay		-	-
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ (358,248)	$ (150,668)
4	Tax Rate	39.23%		
5	Tax Effect (L. 3 * L. 4)			59,099
6	Adjustment - Post Tax (L. 3 - L. 5)			$ (91,568)
7	Revenue Conversion Factor			1.64541341
8	Revenue Requirement (L. 6 * L. 7)			$ (150,668)

Calculation of ND Allocation 1/

Sub Function	Sub-Function Allocator	Sub-Function Amount	ND Allocator	ND Allocation
ADMINISTRATIVE & GENERAL EXPENSES				
SALARIES, SUPPLIES, PENSIONS & BENEFITS				
PRODUCTION	37%	134,056	40.2432%	53,949
TRANSMISSION	15%	53,451	41.2573%	22,052
DISTRIBUTION	24%	84,224	44.0292%	37,083
CUSTOMER ACCOUNTS	18%	64,055	43.2566%	27,708
CUSTOMER SERVICE & INFO	6%	22,462	43.9668%	9,876
Total Management Incentive	100%	358,248		150,668

1/ Allocation factors taken from "4A - 2007 ND TY-12 Labor Annual Increases, KPP, management incentive ADJ.xls."

Depreciation
Staff Adjustments 2, 3, 4, 5 and 6

Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Staff Depreciation Rates	Adj. 6 Reduce Dep Expense for New Plant
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
(268,864)	(12,095)	209,145	(1,339,694)	(48,611)
-	-	-	-	-
$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (48,611)
$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 48,611
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
105,462	4,744	(82,037)	525,496	19,068
$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 19,068
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
-	-			
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
1,053,257	12,095	(209,145)	1,339,694	48,611
8.62%	8.62%	8.62%	8.62%	8.62%
$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,190
1.645413	1.645413	1.645413	1.645413	1.645413
$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (41,716)

Explanations:
Adjustment No. 2 is an exact reversal of OTP Rate Base Adjsument No. (D) and OTP Income Adjustment No. (H
Adjustment No. 3 is an exact reversal of OTP Rate Base Adjusment No. (E) and the related income adjustment t
Adjustment No. 4 is an exact reversal of OTP Rate Base Adjustment (F) and the unbundled portion of its Income
Adjustment No. 5 implements Staff's Revised depreciation rates by ratioing the revised expense to OTP's Propos

a.	OTP Present Depreciation	$	28,173,452	Response to Staff DR 02-172
b.	OTP Proposed Depreciation	$	27,672,037	Response to Staff DR 02-172
c.	1-(L.b./L.a.)		1.7797%	
d.	Staff Expense	$	24,522,162	

e.	1-(L.d./L.b.)		11.4000%
f.	Company proposed change	$	209,145
g.	L.f./L.c.	$	11,751,700
h.	L.g. X L.e.	$	1,339,694

Adjustment No. (I) to reflect Staff's depreciation rates.

i.	L.d./L.b.		88.6%
j.	Company Adj. (I)	$	479,389
k.	Correct Amount (L(i) X L.(j))	$	424,739
l.	Adjustment	$	(54,650)

l)
hat OTP bundeled into its income adjustment (J).
Adjustment (J).
;als as follows:

Exhibit_____(CWK-4)

Otter Tail Power's response to ND PSC IR No. 03-002

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-862

Response to:	North Dakota Public Service Commission
Analyst:	Diller_King_03
Date of Request:	2/27/2009
Date Received:	2/27/2009
Date Due:	3/27/2009

Information Request No. ND 03-002

Staff is concerned with the very large increases that some customers will experience under the revised rate structures proposed by OTP, quite regardless of the overall level of revenue increase. Staff is considering a recommendation of limiting any one customer's rate increase to 50% over the class increase or, for those classes receiving less than a 6.7% increase, 10 percent on an annualized basis in the first year. Subsequent annual increases would be capped at 5 percent until the proposed rates are fully implemented. Exceptions would be customers with average monthly bills of less than $10 and customers who are able to switch to other rate schedules that would result in increases below the cap limits. The revenue shortfall from the capped bills would be made up in the form of across-the-board increases on all other customers.

a. Would OTP oppose this plan and, if so, why?
b. What would be the obstacles to implementing this plan?
c. Can OTP recommend an implementation program for this plan?

RESPONSE:

OTP has reviewed its proposed rate design with the above parameters in mind. The following response discusses the results of that review and suggests rate design modifications that could meet the majority of the parameters suggested in this IR without the need for a "phasing-in" of rate design.

a. OTP does not oppose the majority of Staff's proposal, but, as explained in this response, OTP would prefer to establish a rate design in this case that does not require the design to be "phased-in." Therefore, OTP is providing an alternative rate design in this response that would not require a phasing-in, while both accommodating the majority of the Staff's recommended increase limitations and most of OTP's rate design objectives (including those that would make progress toward meeting the new Federal Economic Stimulus package's goals of efficient use of energy (Section 410)). See OTP's Attachment 1 to IR ND 03-002 for details on this alternative proposal.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

b. There are a few obstacles to a "phase-in" approach to rate design. Such an approach would add significant additional administrative expense in developing and implementing each phase of such a plan, however designed. Additional customer notices would need to be provided in years subsequent to final rates in this case. Those notices and the frequency of rate adjustments during the phase-in period would likely be confusing to many customers. An obstacle might also be created by phasing-in rate design, as OTP expects that it may file another general rate case within three years. It would be an obstacle to implement any portion of the phase-in of rate design at the same time interim rates for the next case are being applied.

   If a current non-phase-in approach is taken to accommodate the request, as proposed in Attachment 1 to IR ND 03-002, there is an obstacle to meeting precisely each criteria identified in the Staff's request. However, because the proposal included in Attachment 1 to IR ND 03-002 comes so very near to meeting each criteria of the request and does not require a phasing-in, OTP believes it is preferable to a plan that would phase-in rate design changes.

c. Attachment 1 to IR ND 03-002 is OTP's matrix of rates, issues and explanations relating to OTP's recommended alternative to meeting Staff's request. As explained in that attachment, there are some rates (very few) that cannot be reasonably adjusted to meet the precise limitations recommended by Staff. OTP's footnotes in the attachment explain the logic of why these few rates should not be adjusted. There are four basic categories into which OTP's rates fall compared to the increase limitations suggested in Staff's request:

   i. Category 1. OTP's originally proposed rate meets the criteria without any change. These rates include: Large General Service, Large General Service Off-Peak Rider, Irrigation Option 1 and Controlled Service-Interruptible Load (CT Metering) Rider.

   ii. Category 2. The rate is being cancelled. When looking at the duo-decile chart for the rate, the impact shown is that of customers moving to other rates. The duo-decile is not for the cancelled rate. These rates include: Commercial Demand Control Customers Billed on Small General Service Less Than 20 kW, Electric Climate Control Customers Billed on Small General Service Less Than 20 kW, Commercial Demand Control Customers Billed on General Service Equal to and Greater Than 20 kW Electric Climate Control and Customers Billed on General Service Equal to and Greater Than 20 kW.

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Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

iii. Category 3. OTP has modified its originally proposed rate to accommodate Staff's increase limitations. OTP's modifications include moving revenue requirements to another rate in the class, adding a declining block component to the rate, or modifying the customer and/or facilities charge. These rates include: Residential Service, Residential Controlled Demand, and Farm Service.

iv. Category 4. OTP's originally proposed rate is very close to meeting Staff's increase limitation, but does not exactly meet all limitations. These rates include: Small General Service Less Than 20 kW, Small General Service 20 kW and Greater, Irrigation Option 2, Municipal Pumping, Civil Defense-Fire Siren, Water Heating – Controlled Service Rider, Controlled Service-Interruptible Load (Self-Contained) Rider, Deferred Load Rider Fixed Time of Delivery (Self-Contained Meter) Rider and Fixed Time of Delivery (CT Meter) Rider.

OTP determined the parameters of this IR as follows, based on its understanding of the request: Limit rate increases to 50% over the class increase and, for those classes receiving less than a 6.7% increase, limit the increase to 10%. OTP's plan limits the increase at the duo-decile level.

Attachment 1 to IR ND 03-002 lists the duo-decile figures, from Mr. Prazak's testimony, that prior to any modifications would have met or not met the limiting criteria recommended by Staff's request. Out of the 22 duo-decile figures, 17 duo-decile figures have one or more duo-deciles that would have exceeded the limitations.

For those duo-deciles that did not meet the limiting criteria, a different set of criteria (impacts from dollar and percent, usage predictability, and rates to be closed) were identified and catalogued for each of the 17 duo-decile figures. Based on these results, OTP selected three rate designs for adjustments based mainly on the criteria contained in B1 or B4 (i.e. percent impacts) listed at the bottom of Attachment 1 to IR ND 03-002.

Attachment 2 to IR ND 03-002 contains the three rate design adjustments identified in column H of Attachment 1 to IR ND 03-002, with one exception (Municipal Pumping, which is explained later). The adjustment techniques used included: (1) changing customer and/or facilities charge; (2) re-introducing declining blocks; and (3) shifting revenue requirements within a class (e.g., Residential Demand Control to Residential Service). Shifting revenue requirements across classes was not used.

Responding Witness:	David G. Prazak
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Date of Response:	4/1/2009

As shown in Attachment 2 to IR ND 03-002, each of the three rate design adjustments shows two duo-decile bar graphs (on the left - per Mr. Prazak's testimony, and on the right – a revised duo-decile graph to meet the criteria recommended by Staff). Below the duo-decile graphs are the originally proposed and revised rate designs.

The Municipal Pumping duo-decile is included for discussion purposes. Even though it received a B4 criterion (i.e. only the last duo-decile exceeded the limit), the rate re-design was not performed as it only exceeded the limit by one (1) percent.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	4/1/2009

OTP's Overall Matrix of Results - Limiting Bill Impacts & Potential Rate Design Adjustments

A	B	C	D	E	F	G	H
Figure No.	Figure Name in Testimony (Prazak)	Customer Class	Otter Tail's Requested Class Increase	Upper-Limit Class Increase Per ND-03-002	Any Duo-Decile Above Upper Limit	Criteria to Determine Rate Design Adj.	Adj. Rate Design Proposal
Figure 1	Residential Service	Residential	7.50%	11.25%	Yes	A1, B5	Yes
Figure 2	Residential Controlled Demand	Residential	7.50%	11.25%	Yes	B1	Yes
Figure 3	Farm Service	Farm	7.50%	11.25%	Yes	A1, B4, B5	Yes
Figure 4	Small General Service Less Than 20 kW	General Service	0.95%	10.00%	Yes	A1, B5	-
Figure 5	Commercial Demand Control Customers Billed on Small General Service Less Than 20 kW	General Service	0.95%	10.00%	Yes	B2, D	-
Figure 6	Electric Climate Control Customers Billed on Small General Service Less Than 20 kW	General Service	0.95%	10.00%	Yes	A1, D	-
Figure 7	Small General Service 20 kW and greater	General Service	0.95%	10.00%	Yes	A1	-
Figure 8	Commercial Demand Control Customers Billed on General Service Equal to and Greater Than 20 kW	General Service	0.95%	10.00%	Yes	A1, B4, D	-
Figure 9	Electric Climate Control Customers Billed on General Service Equal to and Greater Than 20 kW	General Service	0.95%	10.00%	Yes	B2, D	-
Figure 10	Large General Service	Large General Service	1.00%	10.00%	-	-	-
Figure 11	Large General Service Off Peak Rider Customers billed on the Large General Service Rate	Large General Service	1.00%	10.00%	-	-	-
Figure 12	Irrigation Option 1	Irrigation	10.00%	15.00%	-	-	-
Figure 13	Irrigation Option 2	Irrigation	10.00%	15.00%	Yes	C	-
Figure 14	Municipal Pumping	Other Public Authority	14.00%	21.00%	Yes	A1, A2, B4, B5	-
Figure 15	Civil Defense-Fire Siren	Other Public Authority	14.00%	21.00%	Yes	A2, B2	-
Figure 16	Water Heating -Controlled Service Rider	Controlled Water Heating	10.00%	15.00%	Yes	A1, A2, B5	-
Figure 17	Controlled Service-Interruptible Load (CT Metering) Rider	Interruptible	35.00%	52.50%	-	-	-
Figure 18	Controlled Service-Interruptible Load (Self-Contained) Rider	Interruptible	35.00%	52.50%	Yes	B5	-
Figure 19	Standby Service	Interruptible	35.00%	52.50%	-	-	-
Figure 20	Deferred Load Rider	Deferred Load	11.00%	16.50%	Yes	B5	-
Figure 21	Fixed Time of Delivery (Self-Contained Meter) Rider	Deferred Load	11.00%	16.50%	Yes	A1, B4	-
Figure 22	Fixed Time of Delivery (CT Meter) Rider	Deferred Load	11.00%	16.50%	Yes	B1	-
					17		3

Legend

A Dollar ($) Bill impact levels/month

B Percent (%) Bill impact levels/month

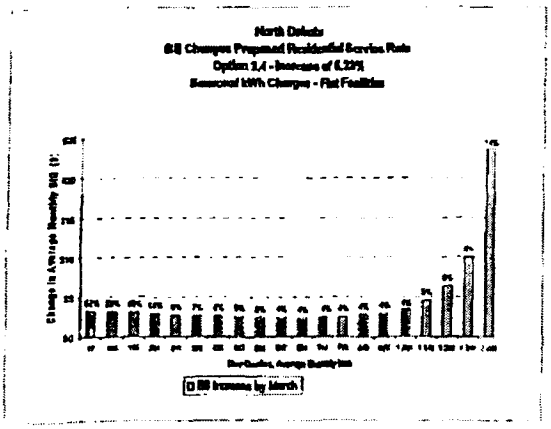
C Usage - Small Class

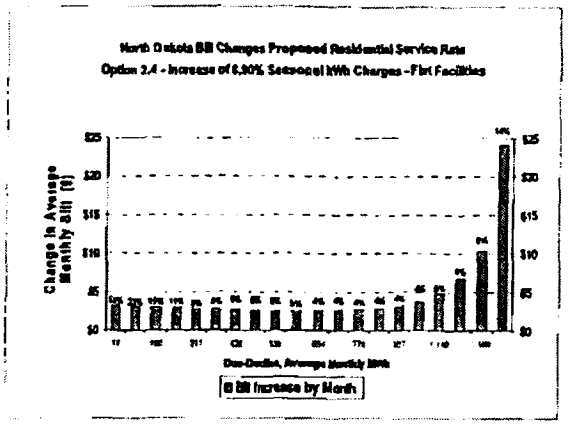
D Rates Proposed to be Eliminated

A1	Some monthly bill impacts around or less than $5/month
A2	All or some duo-decile bill impacts less than $1/month
B1	All duo-deciles exceed limits
B2	Majority of duo-deciles exceed limits
B3	Only first duo-decile bill impact exceeds limit
B4	The last three or less duo-decile bill impacts exceeds limit
B5	Majority of duo-deciles do not exceed limits
C	Rate Design difficult to adjust for few customers with unpredicable usage
D	Rates Proposed to be eliminated
-	Not Applicable

Residential Service

41,638 customers, 2,082 per a decile

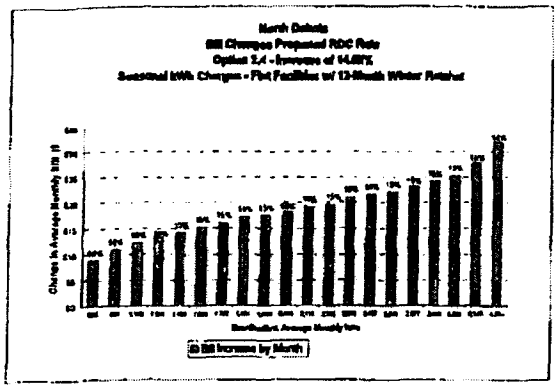


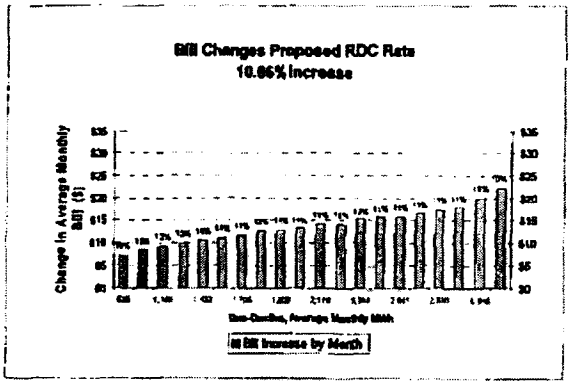


	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		Energy Charge per kWh All Year	Summer	Winter
4 Filed - Proposed Rate	$3.00	$3.00			All kWh	$0.08520	$0.07772
Customer Charge, Seasonal Energy, No Declining Block		+Facilities					
Flat Facilities Charge			$5.00				
				Water Heating Credit	-$4.00		
4 Adjusted - IR 3-2 Rate	$3.00	$3.00			All kWh	$0.08582	$0.07826
Customer Charge, Seasonal Energy, No Declining Block		+Facilities					
Flat Facilities Charge			$5.00				
				Water Heating Credit	-$4.00		

Residential Demand Control (RDC)

3,815 RDC customers, 191 per a decile

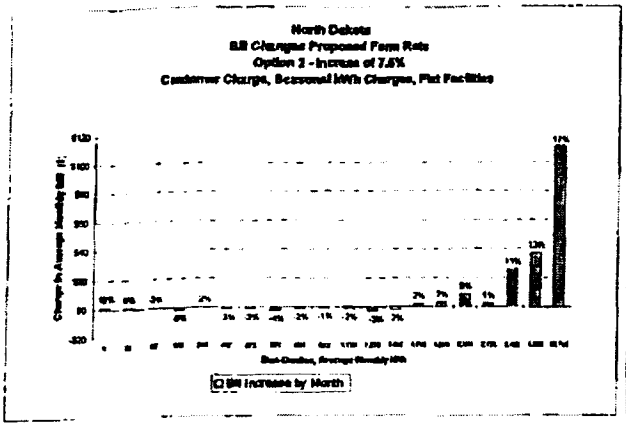


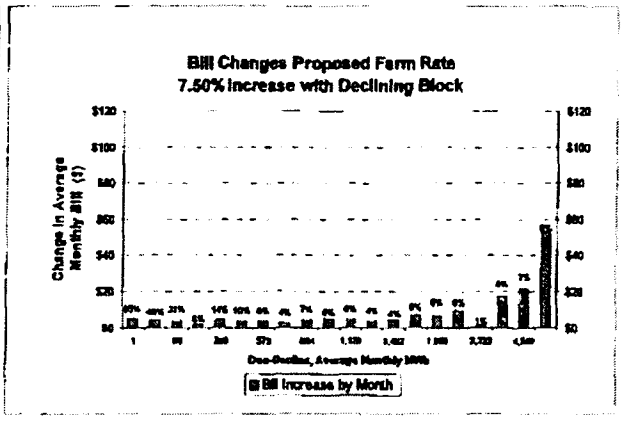


		Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month		Charge per kWh Summer	Winter	Demand Charge per kW per mo. Summer	Winter
Filed									Winter Ratchet
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$9.38	Customer + Facilities Charge			All kWh	$0.04497	$0.04934	$5.88	$2.78
				Fixed Facilities	$8.00					
					$8.00					
										Winter Ratchet
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$9.38	Customer + Facilities Charge			All kWh	$0.04700	$0.04745	$5.82	$2.68
				Fixed Facilities	$8.00					
					$8.00					

Farm Service

1,049 customers, 52 per a decile

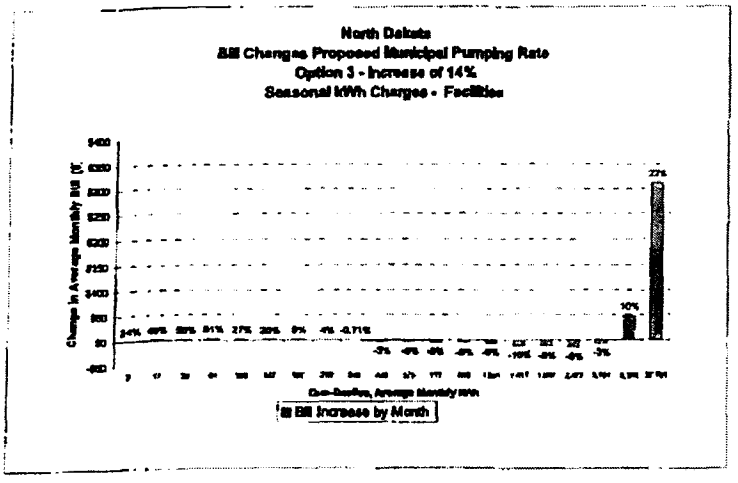


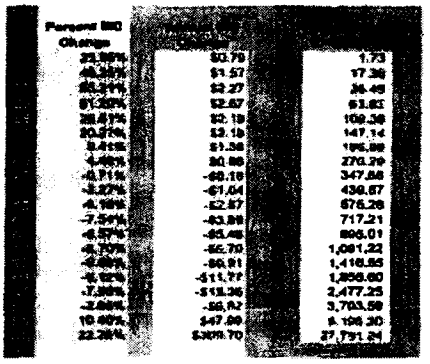


	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per kVA of Transformer	Summer	Energy per kWh Winter	All Year
2 Filed Proposed Rate				3-Phase Surcharge per Mo.			
No Declining Block Seasonal Energy Customer Charge Facilities for 3ph	$8.00	Cust + Fac	Overhead <25 kVA	$4.61	$0.07327	$0.06684	All Energy
			25 kVA or more	$5.61			
			Underground <25 kVA	$13.42			
			25 kVA or more	$21.56			
2 Adjusted Rate				3-Phase Surcharge per Mo.			Energy
Declining Block Seasonal Energy Customer Charge Facilities for 3ph	$12.00	Cust + Fac	Overhead <25 kVA	$3.37	$0.07782	$0.07080	first 1 000
			25 kVA or more	$3.83	$0.06597	$0.06016	Excess
			Underground <25 kVA	$9.39			
			25 kVA or more	$10.78			

Municipal Pumping (OPA)

575 customers, 29 per duo-decile





		Customer $ per month	Minimum Bill $ per month	Facilities Charge $ per month	Summer	Winter	All Year
					$ per kWh per month		
Current Rate		na	$3.30 per metering pt.	na		1st 2500:	$0.07152
						Next 1500:	$0.05832
						Excess:	$0.04768
Rate 3 Seasonal Energy, Facilities Charge Filed - Proposed Rate							
	Secondary	$4.00	Cust + Fac	$4.00	$0.06523	$0.05960	all Energy
	Primary	$4.00	Cust + Fac	$2.58	$0.06494	$0.05922	all Energy

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

In the Matter of the Application of Otter Tail Power Company,
For Authority to Increase Rates for
Electric Service in North Dakota

Case No. PU-08-862

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.

April 2009

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Introduction

Q. State your name, position, and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1111 14TH Street, N.W., Suite 300, Washington, D.C. 20005.

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of 12 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 38-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes, Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Staff of the North Dakota Public Service Commission.

Subject and Purpose of Testimony

Q. What is the subject of your testimony?

A. This case involves a filing by Otter Tail Power Company ("OTP") for authority to increase its rates by $6.1 million or 5.14 percent.[1] My testimony addresses the increase.

Q. What is the purpose of your testimony?

A. I have reviewed the Company's filing and based upon my findings and based on my review and analysis I have identified several monetary and non-monetary adjustments that should be made to the Company's filed request The monetary adjustments, which also incorporate a stipulated 8.62 percent rate of return, would reduce OTP's increase from $6.1 million to a $4.9 million increase.

Prior Experience

Q. Do you have any specific experience in the public utility field?

A. Yes, I have been in the field of public utility regulation since the late 1970's. My testimony has addressed numerous revenue requirement issues. Furthermore, I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject

[1] Brause Direct, p.2.

before the regulatory commissions of almost every state in the country.

Summary of OTP's Filing

Q. Summarize the Company's filing in this case.

A. OTP's policy witness, Mr. Brause, proposes a $6.1 million or 5.14 percent rate increase.[2] The Company's revenue requirement witness, Mr. Beithon elaborates that, "Since OTP last set its rates 24 years ago ... two primary drivers have created a need for a rate increase. ... The most significant increases driving the revenue requirement are: a 130 percent increase in North Dakota non-fuel operating and maintenance costs, which is a 5.40 percent increase using a simple average over 24 years; and a 151 percent increase in North Dakota fuel and purchased power costs, a portion of which are not currently recovered through the Fuel Clause Adjustment (FCA).[3] The Company's Notice summarizes the need for the rate increase as "The revenue deficiency is largely a result of increases in rate base and investment-related costs driven by the Company's additional investments in generation and transmission infrastructure since the last general rate application, which employed a 1983 test year."[4]

General Comments

Q. Do you have any general comments regarding OTP's requested increase?

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[2] Id.
[3] Beithon Direct, page 3.
[4] Notice, page 2.

A. Yes, in my opinion, a 5.14 percent increase after 24 years reflects a good track record, however, this rate case comes at a time when energy, gasoline and food prices are sharply increasing and the national economy is in a severe recession. Consequently, this is no time to increase ratepayers' bills for unnecessary policy changes and overstated non-cash costs. In fact, it is a time to potentially reconsider prior policies that increased customer rates merely based on theoretical accounting issues rather than core operating and maintenance cost issues. Although I do not advocate the adoption of cash-basis accounting, I do recommend recognition of cash realities when arguments such as intergenerational equity are raised as an issue to extract cash payments from ratepayers for non-cash costs.

Q. Have you investigated the Company's rate request?

A. Yes, my assistant and I read the Company's filing and propounded numerous data requests related to the Company's rate request. North Dakota Public Service Commission staff member Mr. Diller also propounded several data requests. We have reviewed those responses and conducted independent analyses as a basis for my testimony.

Depreciation

Q. Is depreciation an important aspect of this case?

A. Yes, it is. Ms. Brutlag identifies several adjustments to depreciation expense netting to a $560 thousand increase to a non-cash expense. I disagree with almost all of Ms. Brutlag's depreciation adjustments.

Q. Are there any general principles relating to depreciation that you wish to explicitly identify and address?

A. Yes, there are several. First, depreciation rates are largely set based on forecasts of future costs of removal that are highly suspect under the best of circumstances. There is great uncertainty caused by the fact that these costs will not be incurred until the plant is removed from service. The expected remaining life of the plant is a forecast, the accuracy of which will not be known until the plant is removed years or decades from now. The cost of removing that plant when the remaining life actually ends is a similar forecast of costs from far off in the future.

Typically rate cases involve substantial differences of opinion over the appropriateness of forecasts of costs that will be incurred only a year or two from now. It is hard to imagine that forecasts of removal costs that will be incurred many years after the test year could be any more accurate than the forecasts of costs that will actually arise during this rate case cycle. It does not increase the comfort in these forecasts when the amount a utility claims to have retired in the past represents a very small proportion of the total plant in service today.

Second, the terms "matching" and "intergenerational equity" (or inequity) often arise in discussions of utility depreciation practices and rates. To most accountants "matching" refers to matching revenues to the periods they are earned and costs to the periods in which they are incurred. Company

witnesses usually point to the matching principle as a rationale for adopting their proposed depreciation rates. Unfortunately, the inappropriate interpretation of matching does not justify charging current ratepayers for un-incurred future inflation to money not yet spent; yet, that is precisely what OTP proposes.

Intergenerational equity is similar to matching, as it encourages the Commission to assign costs of providing utility service to the same "generation" of ratepayers that benefited from that utility service. In depreciation discussions, intergenerational equity means that the customers who took service while a plant was in service pay the costs associated with that plant, including the cost of removing the plant from service when it reaches the end of its useful life. Assume a piece of equipment will be in service for ten years. Intergenerational equity is achieved if the total costs associated with that plant, including removal costs at the end of its life, are collected from ratepayers during the decade the plant is in service, rather than from those taking service before or after that decade.

For purposes of assessing an intergenerational equity argument, then, the Commission needs to know what "generation" the party has in mind. The test year for a rate case, or even the entire period covered by the authorized rates could be viewed as a "generation." A cost recovery pattern that appears to achieve intergenerational equity from the perspective of a ten-year "generation" of utility ratepayers (that is, those taking service while a particular

piece of equipment is in service) may not be equitable when viewed from the perspective of customers who take service early during that generation, yet bear costs that will not arise until much later in the ten-year period.

A third important concept is "straight-line recovery." The concept begs the question "straight-line of what?" To illustrate, assume that the Commission adopts a forecast saying OTP will need to collect $10,000 between 2009 and 2018 to cover the net salvage costs for plant it expects to retire from service in 2018. OTP contends that straight-line recovery must be achieved in nominal dollar amounts, that is, by collecting $1,000 per year for ten years. The Commission should use "real" dollars (that is, inflation-adjusted dollars) to achieve straight-line recovery. The same amount in real dollars is recovered in each of the ten years, but the nominal dollars vary to match inflation for each year (and are paid in dollars subject to that same level of inflation). At the end of the ten-year period, the same amount of nominal dollars is recovered under each of the two approaches. So any assertion that an approach achieves "straight-line recovery" needs to be greeted with the inquiry "in terms of nominal or real dollars?"

Q. Please discuss you specific disagreements with M's. Brutlag's depreciation proposals.

A. First, I disagree with Ms. Brutlag's proposal to allocate accumulated depreciation and depreciation expense to North Dakota rather than directly assigning depreciation as has been the past practice. OTP has been using

depreciation rates approved by the Minnesota Commission, but at one point, North Dakota had its own depreciation ~~rates~~. For reasons I will discuss below, I recommend that North Dakota discontinue blanket approval of Minnesota depreciation rates and adopt its own North Dakota depreciation rates once again. There is no need to discontinue the current practice of directly assigning depreciation. I also disagree with Ms. Brutlag's proposal to increase depreciation expense by $12,095 for depreciation rate changes occurring after the end of 2007. This adjustment reflects nothing more than a decision by the Minnesota Commission to increase North Dakota service rates. I have also reduced M's. Brutlag's proposed depreciation rates, to eliminate the future inflation incorporated into those depreciation rates.

New Depreciation-Related Information

Q. Have recent accounting pronouncements revealed any new information relating to depreciation?

A. Yes, recent accounting pronouncements reveal that OTP's prior recognition of future cost of removal in depreciation rates has resulted in significant liabilities to ratepayers.

Q. Do you have any preliminary comments concerning this issue?

A. Yes, it is my understanding that ""The parties have tentatively settled this issue and are working on a final settlement document. As agreed, we are omitting discussions on this issue unless a final settlement cannot be reached or the Commission does not accept the proposed settlement. In the event the

settlement is not finalized or accepted for any reason, the parties have agreed LIG will be allowed to file testimony on this issue within five business days of such a determination."

Q. What is the genesis of this new information?

A. The genesis of the new information is the Financial Accounting Standards Board's ("FASB") 2002 Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") which addresses asset retirement obligations (AROs) associated with long-lived plant.[5]

SFAS No. 143's focus is legal obligations to incur a cost when an asset is retired – legal asset retirement obligations ("legal AROs"). SFAS No. 143 considers such obligations to be a component of the original cost of the asset. It requires capitalization and depreciation of the discounted fair value of the estimated asset retirement cost over the asset's life.

SFAS No. 143 also identified a significant regulatory liability resulting from public utilities' past inclusion of excessive future cost of removal and dismantlement factors in depreciation rates. The Federal Energy Regulatory Commission ("FERC") identified these amounts as "non-legal" asset retirement obligations, meaning that the utilities do not have actual legal obligations and liabilities to incur these costs in the future.[6] SFAS No. 143 requires reporting

[5] FERC Order No. 631 is that agency's implementation of SFAS No. 143 for regulatory purposes for utility operations subject to that agency's jurisdiction.
[6] FERC Order No. 631, para. 36.

of non-legal AROs as regulatory liabilities to ratepayers - if the requirements of SFAS 71 are met.[7]

Q. What conditions create a regulatory liability using GAAP?

A. SFAS 71, ¶11, provides that a regulator's rate actions impose a liability on the utility to its customers (regulatory liability) if the regulator provides "current rates intended to recover cost expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts."[8] For Commission-regulated utilities, this "understanding" has been implicit. Nevertheless, it is sufficiently clear to OTP to warrant creation of the regulatory liability for GAAP financial reporting purposes. Now that SFAS No. 143 has identified the amounts, this Commission should recognize them as the regulatory liabilities they are.

Q. Does OTP have any regulatory liabilities relating to non-legal AROs?

A. Yes, OTP reports a $57.8 million regulatory liability in compliance with SFAS No. 143 in its December 31, 2007 Form 10-K Report.[9] North Dakota's portion of the regulatory liability is $22.9 million.[10]

Q. What is the nature of this regulatory liability?

A. This liability consists of the cost of removal money OTP collected from ratepayers over and above its actual removal cost expenditures.

Q. What do you recommend?

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[7] SFAS No. 143, paragraph B.73.
[8] SFAS No. 71, ¶11 and 11(b).
[9] December 31, 2007 10-K Report, p. 124.
[10] 39.61% per response to ND 02-212

A. I have three recommendations:

1. This Commission should specifically recognize, on the record, the $22.9 million as a regulatory liability for reporting and ratemaking purposes in North Dakota. It should require OTP to transfer this amount from the North Dakota depreciation reserve to account 254-other regulatory liabilities.
2. This Commission should require OTP to file a North Dakota specific depreciation study.
3. The Commission should also instruct OTP to use the present value approach if it includes future removal and dismantling costs in its calculation of depreciation rates.

Q. Why is it necessary for the Commission to recognize a regulatory liability for the non-legal cost of removal and dismantlement amounts?

A. Although the FERC has recognized and required isolation of the amount within the utility's accounting system, FERC did not require reporting the amount in FERC Form 1. FERC also failed to require reporting them as regulatory liabilities. FERC deferred these decisions to the states, which are the primary ratemaking bodies. Consequently, while FERC Order No. 631 implies a new transparency by requiring identification of the amounts and maintenance of separate subsidiary records for regulatory analysis and rate setting purposes, it did not specifically recognize a regulatory liability for non-legal AROs. The

$22.9 million North Dakota amount is clearly not identifiable in this rate case other than through my testimony.

As a result, nothing holds OTP specifically accountable for these excess collections, even though the public accounting profession and the Securities and Exchange Commission recognize that they are regulatory liabilities and that the PSC implicitly holds OTP accountable.

Regardless of the implied transparency provided by FERC's new requirements, OTP does not even identify or mention these requirements or the issue in its rate case filing. This is an intolerable situation. The accountability must be explicit, and the Commission must establish that accountability.

My experience shows that it is unlikely that all of the amounts collected will be spent for future cost of removal. Nevertheless, even if it was highly probable that OTP might spend all this money for future cost of removal, it is fair and reasonable for the Commission to recognize the ratepayers' claims on these monies until actually spent on their intended purpose. Unless they are explicitly identified as "subject to refund," there is an ongoing and unnecessary risk that they are merely hidden potential income to OTP.

It is critical that the Commission require OTP to explicitly identify and report this regulatory liability and all related activity in all future reports, rate cases and depreciation studies that it files with the Commission. The Commission should require prominent disclosure of its explicit recognition of

this amount as an intrastate regulatory liability in OTP's future FERC Form 1 reports to ensure sufficient recognition of and transparency concerning these amounts. Without a requirement for separate identification and reporting of these amounts, they are hidden from the ratemaking process and regulatory scrutiny in North Dakota.

Q. What is wrong with continuing to record the regulatory liability as accumulated depreciation?

A. OTP and all utilities consider accumulated depreciation to represent the measure of their capital that they have recovered from their ratepayers. As simplistic as it sounds, *utilities consider any amount in accumulated depreciation to be "their money" even if they collected it for a fictitious future cost.* OTP specifically states that is the "Company's money" in response to ND 02-218 i.

Q. Does OTP agree that its collections for non-legal AROs result in a regulatory liability?

A. A. No. OTP emphatically denies that its $57.8 million of excess collections for non-legal AROs constitute a regulatory liability, even though it reports it as such.[11]

Q. Why does OTP take this position?

A. OTP knows that if regulation changes, it will transfer the unspent money to its equity account rather than returning it to ratepayers.

[11] Response to ND 02-218.

The Edison Electric Institute and several individual utilities fought hard to avoid having either the FASB or FERC require the identification and reporting of the regulatory liability that I have just described.

If OTP were to be deregulated, or if regulation were to change from "cost-based" to some form of alternative "price-based" regulation, history tells us the Company would have every interest in immediately transferring its $57.8 million regulatory liability into its GAAP income. This amount could well disappear from the scene unless the Commission protects it on behalf of ratepayers. Therefore, this amount must be specifically designated as a regulatory liability for ratemaking purposes.

Q. Why do you believe that OTP would transfer its $57.8 million non-legal regulatory liability into GAAP income?

A. It will transfer the regulatory liability into GAAP income because that is what GAAP requires. If deregulated, or if regulation changes significantly, the provisions of SFAS No. 71 will no longer apply. The regulatory liability amount will flow immediately and explicitly to GAAP income, because SFAS No. 143 requires it to flow to income if it is not payable to ratepayers. This is what some electric utilities did when their production plants were deregulated, and this is what OTP warns it will do in its 2007 10-K Report.

Q. Do you have any credible evidence of such treatment in the past?

A. Yes, American Electric Power had several of its production plants deregulated. It immediately transferred $473 million from accumulated depreciation into income relating to those deregulated plants.[12]

In another example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[13]

This means that TEP transferred non-legal AROs into income.

For its regulated operations, which include the transmission and distribution portions of its business, TEP continued to apply SFAS 71. As a result, TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability.

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[14]

However, TEP also reported:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and

[12] AEP 2003 Annual Report to Shareholders, page 69.
[13] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.
[14] Id., page K-60.

its regulatory liabilities as income on its income statement.[15]

The term "write off" is a euphemism for transferring the money to income.

Q. Is TEP aware that you have used the quotation above to make the point that given the chance a utility will transfer the regulatory liability to income?

A. Yes, in November 2005, the Public Utilities Fortnightly published an article I wrote concerning the issues at hand in this proceeding. The article included the quotation from TEP's 2004 10-K Report. Subsequently, Karen G. Kissinger, TEP's Vice President, Controller & Chief Compliance Officer responded to my article.[16] Ms. Kissinger leveled several attacks against my logic, but her last sentence corroborated the risk to ratepayers that I identified in the article. Ms. Kissinger finished her letter saying: "Ratepayers are not entitled to a refund of costs recognized to provide services they have already received."[17] That means that TEP believes that its ratepayers should pay it money in advance for future costs of removal, with no expectation of a refund or future rate decrease should TEP not use the funds for their intended purpose – in that event, they belong to TEP. OTP's ratepayers are subject to the same risks.

Q. Have any other industries transferred non-legal ARO amounts into income?

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[15] Id. (Emphasis added.)
[16] Id., page 12. Public Utilities Fortnightly, Letters to the Editor, April 2006, page 10.
[17] Id.

A. Yes, while still regulated, the telephone industry collected substantial amounts of future cost of removal from its ratepayers through depreciation, just as OTP wants to continue doing. Upon deregulation and the adoption of SFAS No. 143, the major telephone companies transferred $11.5 **billion** from accumulated depreciation into their net income.[18]

Q. Can you provide any definitive additional evidence that OTP will transfer the money in the future?

A. Yes, the U.S. accounting profession is presently moving towards the adoption of International Financial Reporting Standards ("IFRS"). Upon adoption of IFRS, the regulatory liability will disappear into equity.[19]

Q. What should the Commission do with the cost of removal regulatory liability on a going-forward basis?

A. There are a number of alternatives to the treatment of the regulatory liability on a going-forward basis. The Commission could require continued maintenance as a permanent rate base offset representing customer-provided capital, or amortization back to ratepayers over some specified amortization period. I prefer an amortization, because I do not believe OTP will ever spend all of this money on future cost of removal, and as long as the money remains in the Company's hands, it will do whatever it can to convert the regulatory liability to income.

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[18] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See SBC, Verizon, Qwest, BellSouth and Sprint's 2003 10K Reports and 2003 Annual Reports to Shareholders.

[19] See Ready for IFRS?, *Public Utilities Fortnightly*, January 2009 and Fixing Depreciation Accounting, *Public Utilities Fortnightly*, October 2008.

Q. What amortization period do you recommend?

A. I recommend a 10-year amortization period.

OTP's Going-Forward Cost Of Removal Proposals

Q. Please explain what is meant by "cost of removal."

A. The cost of providing utility service includes not only the costs of installing and operating utility plant, but also removing that plant where appropriate at the end of its useful life. Therefore, one of the components of a public utility depreciation rate is a current estimate of future cost of removal (or negative net salvage).

This estimate is typically expressed as a ratio (derived from historical data), that is applied to the current plant balance to provide an estimate of the future cost of removal. This future cost is, in turn, charged to depreciation expense on a straight-line basis over the remaining life of the plant, just as the depreciation of plant investment is charged to expense. A cost of removal ratio increases the overall depreciable cost base because it allocates a portion of the estimated future removal cost to each year of the asset's service life. This process is, by definition, accrual accounting.

Q. Do you object to accrual accounting?

A. No, I do not object to accrual accounting if properly applied.

Q. If you are not raising any objection to the general process of forecasting future costs of removal or net salvage, what does your testimony address and how is it different than what OTP proposes?

A. My testimony focuses on providing the Commission with information it needs to address the inflation issue. To that end, my discussion addresses accrual accounting, matching and intergenerational equity principles. I provide a simple and straight-forward example demonstrating that the present value approach is the approach most consistent with these principles because it properly matches inflation expense to the periods incurred and eliminates the intergenerational inequity inherent in OTP's approach. I do not propose any variation on "expensing" or normalizing removal costs. Accepting OTP's future cost of removal proposals at face value, I merely express them at their present value so current ratepayers will not be charged for future inflation that has not been incurred.

In other words, for plant in service today that will likely be removed from service twenty years from now, both the present value approach and OTP's approach would recover the same total amounts. The present value approach would achieve the same straight-line pattern as OTP's approach for recovery of the original plant investment, and for recovery of the inflation-adjusted amount for the net salvage costs that will be incurred in 2029. The only difference is the cost recovery pattern for the future inflation costs; the present value approach would have the annual amounts increase during the twenty-year period to reflect the effects of inflation (and permit OTP customers to pay in inflated dollars), while OTP would allocate the future inflation costs on a

straight-line basis, an outcome that assigns a disproportionate share of those costs to current ratepayers.

Q. Are you challenging any of OTP's proposed lives?

A. No, I am not challenging any of OTP's proposed lives. I think it is more important at this juncture to focus the Commission's attention on how OTP's approach treats future inflation costs. I will show how a simple modification to this treatment can achieve the proper and far more equitable outcome that is consistent with the matching principle, minimizes intergenerational inequity, and has the added advantage of lowering the utility's depreciation rates.

Q. How did OTP arrive at his net salvage or future cost of removal proposals?

A. OTP conducted a "traditional" historical net salvage analysis to estimate future net salvage ratios for each account.

Q. Why do you object to OTP's traditional approach?

A. OTP's approach is front-loaded in its treatment of future inflation costs. It increases the current estimate of future costs of removal for a substantial amount of future inflation. In other words, OTP's approach charges current ratepayers on an undiscounted basis for future inflation. I disagree with OTP's approach from an accounting standpoint as well as from a ratemaking standpoint. Accrual accounting consists of matching costs to the periods in which they are incurred. OTP's approach fails that fundamental test by front-

loading future inflation. This defect is why GAAP specifically precludes his approach.

Q. Why does OTP's approach result in inflated future cost of removal estimates?

A. OTP bases his approach on the relationship of current cost of removal expenditures in today's dollars versus the original cost of the plant being retired, calculating a ratio of current cost of removal (in today's dollars) to original cost of plant (in historical dollars). A substantial part of the current cost of removal represents past inflation experienced during the period (often decades) between when the plant was first put in service and when the removal costs were incurred. OTP then applies that ratio to today's plant balances to project the future cost of removal. In this way, the calculation extrapolates into the future all of the past inflation rather than the small portion actually experienced during the test year 2007.

Accrual Accounting

Q. What is accrual accounting?

A. Accrual accounting recognizes or matches revenue to the periods earned and expenses to the periods incurred. Accrual accounting is the foundation of generally accepted accounting principles ("GAAP"). The directives issued by the Financial Accounting Standards Board ("FASB"), such as SFAS No. 143 and FIN 47 set forth in GAAP.

Q. What is cash basis accounting?

A. Cash basis accounting recognizes revenues and expenses when received or disbursed rather than when earned or incurred.

Q. Does OTP's approach constitute accrual accounting?

A. I do not believe it does, at least to the extent it charges current ratepayers the costs of inflation that may not be incurred for years or even decades. An approach more consistent with accrual accounting would match those future inflation costs to the ratepayers taking utility service at the time the inflation is incurred. OTP's approach does not match inflation costs to the periods incurred.

Q. Do the relatively recent pronouncements of the Financial Accounting Standards Board provide any useful guidance on these questions?

A. I believe they do, even if the questions are arising here in a ratemaking proceeding and the FASB pronouncements apply most directly to financial reporting requirements. But the underlying principles of achieving appropriate "matching" through accrual accounting do not change whether they arise in a ratemaking or financial reporting setting.

OTP is no doubt familiar with the accounting prescribed in SFAS No. 143 and FIN 47, which constitute GAAP. SFAS No. 143 was adopted to establish accounting standards for recognition and measurement of a liability for an asset retirement obligation and any associated asset retirement cost. (SFAS No. 143, ¶ 1.) SFAS 143 provides that where there are no quoted market prices to use for such estimating purposes, a "present value" technique

is often the best available substitute. (SFAS No. 143, ¶ 8.) This present value technique prescribed in SFAS 143 directs the discounting of the estimated future cash flows using "credit-adjusted risk-free rate."

OTP may argue that the Commission should not rely on SFAS No. 143 or FIN 47 for purposes of deciding ratemaking issues. However, for purposes of deciding what approach is most consistent with principles of accrual accounting, I submit there is no better source than FAS 143 and the other FASB pronouncements that are, after all, the embodiment of GAAP. And, under FAS 143 companies are not required to report the absolute future value of removal costs, but rather a "present value" of those future costs. For financial reporting purposes, this better enables investors to assess a company's future asset retirement obligations. For ratemaking, it serves a different purpose. Using a present value calculation of the future costs of removal ensures that the future removal cost expenditure is measured in a way that achieves a fair revenue requirement to charge customers during an accounting period. The present value approach treats OTP's study year as the relevant "accounting period" OTP's testimony refers to.

It is important to be clear about this. In other cases in which I have been involved, utilities have characterized the present value approach as seeking to have the Commission adopt SFAS 143 for ratemaking purposes when, in fact, the utility only adopted SFAS S143 for financial reporting purposes.

I am not asking the Commission to adopt SFAS 143 for ratemaking purposes. However, for the purpose of developing an appropriate estimate of the amount of future removal costs to include in today's rates, the underlying principle is consistent with accrual accounting as set forth in GAAP (of which SFAS 143 is a part); whether the estimate is to be used for financial reporting purposes or for establishing a reasonable rate under cost-of-service ratemaking. The amount that should be charged to the "accounting period" is an appropriate share of the present value of the future obligation. The Commission may choose to use something other than the "credit-adjusted risk-free rate" described in SFAS No. 143 for calculating the present value of the future obligation. For example, I recommend the Handy Whitman indices as the basis to make the adjustment. But the underlying principle of accrual accounting and ratemaking remains – future cost of removal is properly measured and matched to the period incurred. In ratemaking, the accounting period is the current year, not the remaining life of the plant.

Q. Can you demonstrate that using the present value approach constitutes accrual accounting and that OTP's approach does not constitute accrual accounting?

A. Yes. Exhibit___ (MJM-1) is a chart I designed to demonstrate those facts. It is a simple single asset example comparing OTP's approach to collecting future inflation versus the present value accrual approach. The example assumes the present value to remove a single structure is $20,000, but that

will increase over the structures' 20-year life to $53,066 at a 5 percent inflation rate. As you can see, both OTP's approach and the present value approach accumulate the same $53,066 total amount for future removal costs by the end of the asset's life. The difference is the rate of collection for future inflation costs. The present value approach matches inflation to the periods incurred. OTP's approach front-loads future inflation costs into current periods, and by doing so overcharges ratepayers in the early years and undercharges ratepayers in the later years. This flies in the face of the "intergenerational equity" and accrual accounting concepts; it stands them on their heads.

Q. Is this example intended to show rate base effects?

A. No, the example demonstrates that accrual accounting matches inflation to the periods incurred. Rate base is irrelevant to that demonstration.

Q. Is there any economic rationale that supports matching future inflation to the periods incurred?

A. Yes, the inflation-related portion of the future removal cost will be paid for with cheaper dollars in future years. In terms of nominal dollars, the amount to be paid appears to be higher, but in real (that is, inflation-adjusted) dollars, the same amount is paid now and in the future, all else being equal. In other words, if OTP were to retire and remove all of its assets today, it would incur the present value of OTP's same future cost of removal estimates. When it comes to future inflation costs, "straight-line" cost allocation should be measured in real dollars, not nominal dollars.

Q. Is OTP's approach required under the Uniform System of Accounts ("USOA")?

A. No, nothing in the USOA requires depreciation rates to be based on inflated future costs, or to collect from today's ratepayers the costs of inflation that will not be experienced for years or even decades to come.

Consolidated Taxes

Q. Do you have any other examples of OTP collecting funds in excess of its actual costs?

A. Yes, OTP is a participant in a consolidated federal income tax return. These arrangements can result in the ratepayers of regulated entities subsidizing losses of unregulated affiliates. In other public utility cases, I have read tax allocation agreements between the parties to consolidated tax returns. On more than one occasion, I have seen words requiring a pass through of taxes collected from a regulated entity to the parent and from there to the loss affiliates. In fact, that is precisely what is called for in OTP's tax sharing agreement.[20]

Q. Has the Commission employed the stand-alone approach in the past?

A. Yes, it has. However, given the experience with energy, gasoline and food price increases, I recommend that the Commission revisit the issue. In a period of dwindling resources and corresponding upward price spirals, the Commission should at least know the magnitude of the consolidated tax

[20] See response to ND 02-58.

subsidy and reconsider whether captive ratepayers should be required to pay anything more than actual taxes. The Commission should place OTP on alert in this proceeding that it intends to revisit the consolidated tax issue in the next rate case.

Summary of Snavely King Adjustments

Q. Do you have a summary of your individual adjustments to the Company's filed revenue requirement?

A. Yes, Exhibit___ (MJM-2) summarizes the adjustments. It also incorporates a stipulated 8.62 percent rate of return. The adjusted revenue requirement is $.645 million less than OTP's.

Adjustment No. 1 – Implement Stipulated Rate of Return

Q. Please explain each adjustment.

A. Adjustment No. 1 implements the 8.62 percent rate of return to which the parties have stipulated.

Adjustment No. 2 – Reverse Allocation of Depreciation

Q. Please explain Adjustment No. 2.

A. Adjustment No. 2 reverses Ms. Brutlag's proposal to allocate, rather than directly assign depreciation to North Dakota.

Adjustment No. 3 – Reverse Depreciation Increase Using 2008 Depreciation Rates

Q. Please explain Adjustment No. 3.

A. Adjustment No. 3 reverses the $12,095 depreciation increase Ms. Brutlag proposes to reflect the 2008 Minnesota depreciation rates.

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Adjustment No. 4 – Reverse Depreciation Decrease Using Brutlag Proposed Depreciation Rates

Q. Please explain Adjustment No. 4.

A. Adjustment No. 4 reverses the depreciation decrease Ms. Brutlag proposes based on a new study that is yet to be approved by the Minnesota Commission. Even with a decrease these depreciation rates are excessive due to their inclusion of future inflation in the cost of removal estimates.

Adjustment No. 5 – Implement North Dakota Staff Depreciation Rates

Q. Please explain Adjustment No. 5.

A. Adjustment No. 5 implements the North Dakota Staff's recommended depreciation rates. They accept Ms. Brutlag's parameter proposals, but eliminate the future inflation expense from the cost of removal estimates included in the rate calculations.

Adjustment No. 6 – Reduce Depreciation Expense for New Plant

Q. Please explain Adjustment No. 6.

A. Adjustment No. 6 reduces Ms. Brutlag's proposed depreciation expense relating to new plant to conform to the North Dakota Staff's recommended depreciation rates.

Adjustment No. 7 – Charitable Donations

Q. Please explain Adjustment No. 7.

A. Adjustment No. 7 removes charitable donations from the Company's revenue requirement claim. This adjustment results in an $114,816 reduction to the revenue requirement.

Q. Why have you made this adjustment?

A. Otter Tail included in its revenue requirement certain charitable donations. These donations are not necessary for the provision of safe, reliable and efficient electric and natural gas service. While it is commendable that the Company is involved in civic and charitable activities, ratepayers should not be expected to finance those activities. As such, I have removed these donations.

Adjustment No. 8 – STB Litigation Expense

Q. Please explain Adjustment No. 8.

A. Adjustment No. 8 removes $40,973 related to litigation before the Surface Transportation Board from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Included in Otter Tail's test year revenue requirement is $40,973 in expense related past litigation before the STB. Because this litigation effort is finished, any expenses related to it will not be ongoing. Therefore, I have removed the $40,973 from the revenue requirement.

Adjustment No. 9 – Economic Development Expense

Q. Please explain Adjustment No. 9.

A. Adjustment No. 9 removes $108,539 related to economic development from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has proposed increasing the amount included in rates for economic development activities to $500,000. The current annual amount included in rates is $315,557, which was approved during the 1988/1989 time frame.[21] According to Company witness Ms. Brutlag, Otter Tail has averaged $513,698 per year since the inception of the program.[22] While this may be true, the amount is skewed by a $1.3 million expenditure in 1995. A more recent calculation using 2004 through 2008 amounts indicates the Company averages $391,461 in economic development expense.

Otter Tail's economic development activities appear to provide a genuine service to the community, including job creation in many cases.[23] This is particularly important in today's economic environment. However, the rate payers being asked to pay for these activities are also victims of the current economy and should not be asked to pay higher rates in order to finance Otter Tail's community involvement.

Because the previous amount was set in 1988/1989, I have updated the amount to Otter Tail's most recent five-year average of $391,461. This results in a $108,539 decrease to the revenue requirement.[24]

Adjustment No. 10 – Employee Awards

Q. Please explain Adjustment No. 10.

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[21] Brutlag, pp. 18-19.
[22] Exhibit___ (BCB-1), Schedule 2.
[23] See Brutlag, p. 19 and response to ND 02-009.
[24] $500,000 included in Company's claim less $391,461 recommended amount.

A. Adjustment No. 10 removes $76,089 related to employee awards, gifts, dinners and similar activities from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. In its response to ND 02-126, the Company provided the year 2007 amounts for employee gifts, luncheons, dinners, picnics and awards. The total amount was $85,989. This amount includes $36,456 in annual employee service awards and $15,522 in "token gifts given to each employee attending annual executive forum meetings."[25] A review of the invoices provided shows that the awards purchased ranged from hunting knives to flat screen televisions.[26] While I understand that some companies include these types of activities for employees as morale boosters, I do not believe the rate payers should be asked to finance them. As such, I have removed the amounts. However, of the total, $9,900 related to safety award checks.[27] I have allowed that amount to stay in the revenue requirement.

Adjustment No. 11 – Asset-Based Margins

Q. Please explain Adjustment No. 11.

A. Adjustment No. 11 eliminates asset-based margins which Mr. King recommends be flowed through the fuel clause.

Q. Why have you made this adjustment?

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[25] See response to ND 02-126, Attachment 2.
[26] Id., Attachment 1.
[27] Id, Attachment 2.

A. As I stated, Mr. King discusses this adjustment in detail in his testimony. However, I observe that the Ancillary Services Market is up and running, but it just started, consequently, it is probably too early to try and include an amount in base rates. Furthermore, if the margins are not run through the fuel clause adjustment, a perverse incentive could ensue where OTP would be better off setting aside its generating units to provide ASM services and generating ASM revenues (not included in the rate case) and purchasing power for its customers which off course are automatically ran through the FCA.

Adjustment No. 12 – Executive Incentive Pay

Q. Please explain Adjustment No. 12.

A. Adjustment No. 12 removes $150,668 related to executive incentive pay from the Company's revenue requirement claim.

Q. Why have you made this adjustment?

A. Otter Tail has included $358,248 (total company) in executive incentive pay in its revenue requirement calculation. The North Dakota portion of that amount is $150,668. I have removed the entire provision for executive incentives for several reasons. First, as I have discussed several times in my testimony, the current state of the economy should discourage the payment of any bonus plans. Notwithstanding the well-publicized actions of certain companies receiving federal assistance, many companies today are actually instituting pay cuts in order to stay viable during this time. Second, as described in the response to ND 02-102, payment of the executive incentive plan target amount

is 60 percent dependent on the achievement of financial goals (regulated return on equity and return on invested capital), which are designed to benefit shareholders, not ratepayers.[28] The remaining 40 percent is dependent on "individual performance." I do not know what areas of "individual performance" are considered, but there is no indication this is safety or service related, unlike the design of the incentive plan for non-executive employees. If Otter Tail wishes to pay its executives an incentive bonus it should be paid for by shareholders, not ratepayers.

Adjustment Nos. 13 and 14 – Reverse OPEB Transition Costs

Q. Please explain Adjustment Nos. 13 and 14.

A. Both of these adjustments relate to SFAS No. 106 costs which, in turn, are costs associated with Other Post Employment Benefits. Mr. Beithon states that "These costs are tracked in two parts – transition costs and current accrual expenses."[29]

Adjustment No. 13 is a reversal of the Company's 2006 elimination of the so-called transition obligation associated with OPEBs. OTP had apparently recorded a receivable in its prepayments account to reflect the amount it intended to charge ratepayers for the transition obligation. In reality, it appears that it had overestimated the amount it needed for OPEB costs, and in fact did not even create a funded liability for these costs, such as it has for

[28] See response to ND 02-102, Attachment 3, p. 2.
[29] Beithon page 32.

its pension obligation. Consequently, upon adoption of SFAS No. 158, it wrote-off the prepayment/receivable.

In this case, OTP proposes to create $1,678,516 of off-book income merely by crediting its retained earnings account and returning the $1,678,516 into prepayments with a corresponding $335,703 annual amortization expense obligation it would like ratepayers to pay. I reject both of those requests. OTP actually funds its OPEBs on a pay-as-you go basis, just as it has done from the very beginning. It does not maintain a cash fund for these costs. Adjustment No. 13 reverses OTP's attempt to reestablish a receivable from ratepayers for prior OPEB costs, and Adjustment No. 14 reverses OTP's amortization of the fictitious transition receivable. In my opinion, the Commission should also require OTP to begin funding its OPEB liability.

Adjustment Nos. 15 and 16 – Flow MISO Amounts Through Fuel Adjustment Change

Q. Please explain Adjustment Nos. 15 and 16.

A. Adjustment Nos. 15 and 16 reflects Staff's position that MISO costs should be flowed through the fuel adjustment charge.

Adjustment No. 17 – Reverse Non-Asset Based Margins

Q. Please explain Adjustment No. 17.

A. Adjustment No. 17 reverses OTP's proposal to include non-asset based margins in the revenue requirement.

Q. Why did you make this adjustment?

A. I made this adjustment because the Company's proposal allocates more cost from the Company's trading department than it does revenues from non-asset based margins.

Adjustment No. 18 – Reverse DSM and Energy Conservation

Q. Please explain Adjustment No. 18.

A. Adjustment No. 18 reverses OTP's DSM and Energy Conservation charges so they can be recovered through a separate rider.

Q. Does this conclude your testimony?

A. Yes, it does.

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Bedell, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.

Michael J. Majoros, Jr.

Date	Jurisdiction / Agency	Docket	Utility
		Federal Courts	
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
		State Legislatures	
2006	Maryland General Assembly 61/	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates 62/	HB189	Maryland Healthy Air Act
		Federal Regulatory Agencies	
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC 53/	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
		State Regulatory Agencies	
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph

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1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.

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1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company

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2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company

Michael J. Majoros, Jr.

2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

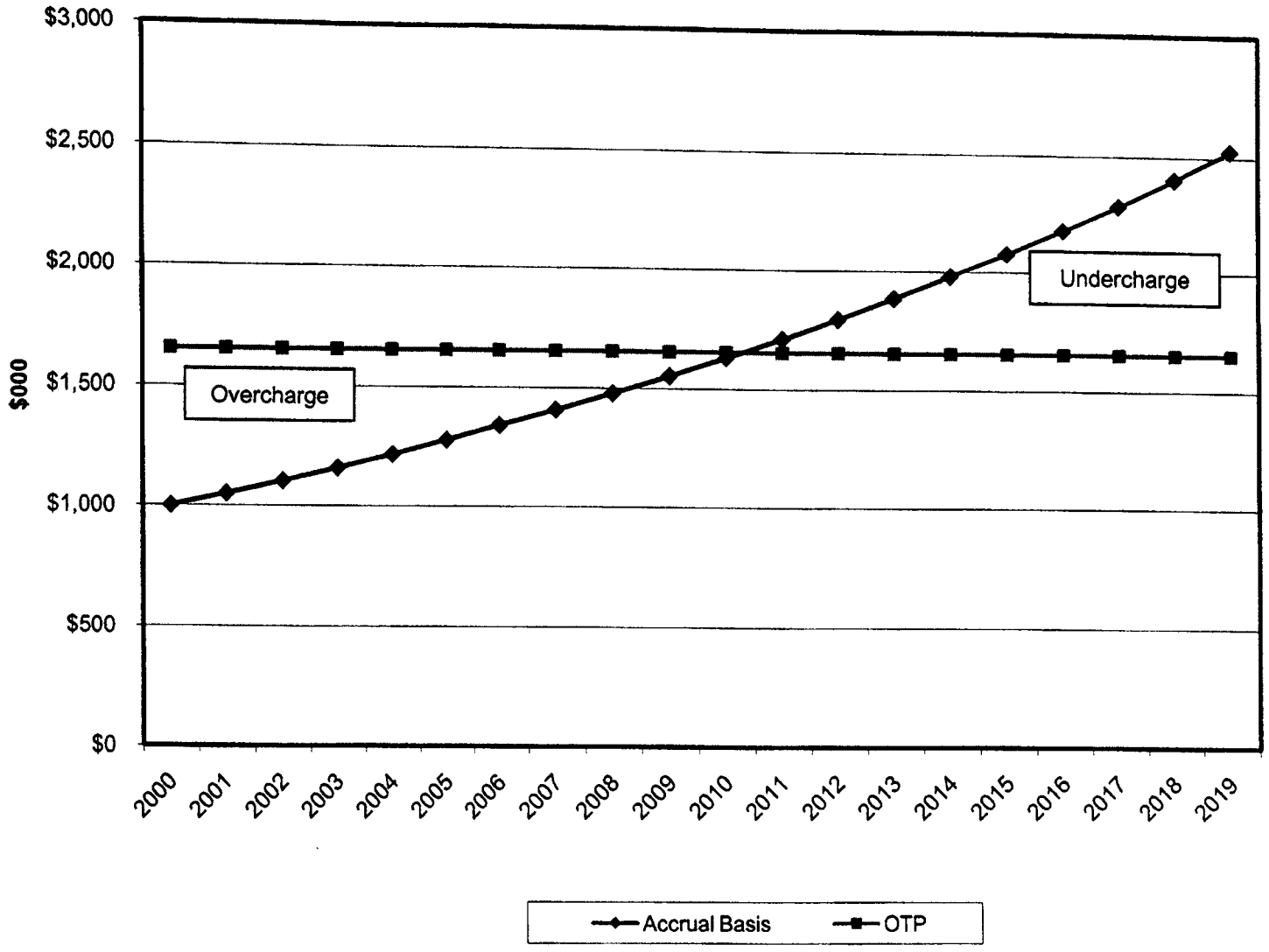
STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	34/ New Mexico Attorney General
2/ West Virginia Consumer Advocate	35/ Environmental Protection Agency Enforcement Staff
3/ Pennsylvania OCA	36/ Kentucky Attorney General
4/ Florida Office of Public Advocate	37/ North Dakota Public Service Commission
5/ Toms River Fire Commissioner's	38/ Kansas Industrial Group
6/ Iowa Office of Consumer Advocate	39/ City of Witchita
7/ D.C. People's Counsel	40/ Kansas Citizens' Utility Rate Board
8/ Maryland's People's Counsel	41/ NIPSCO Industrial Group
9/ Idaho Public Service Commission	42/ Hawaii Division of Consumer Advocacy
10/ Western Burglar and Fire Alarm	43/ Nevada Bureau of Consumer Protection
11/ U.S. Dept. of Defense	44/ GCI
12/ N.M. State Corporation Comm.	45/ Wisc. Citizens' Utility Rate Board
13/ City of Philadelphia	46/ Vermont Department of Public Service
14/ Resorts International	47/ Oklahoma Corporation Commission
15/ Woodlake Condominium Association	48/ National Assn. of State Utility Consumer Advocates
16/ Illinois Attorney General	49/ Nova Scotia Utility and Review Board
17/ Mass Coalition of Municipalities	50/ Florida Office of Public Counsel
18/ U.S. Department of Energy	51/ Maryland Public Service Commission
19/ Arizona Electric Power Corp.	52/ MCI
20/ Kansas Corporation Commission	53/ Transmission Agency of Northern California
21/ Public Service Comm. – Nevada	54/ Florida Industrial Power Users Group
22/ SC Dept. of Consumer Affairs	55/ Sierra Club
23/ Georgia Public Service Comm.	56/ Our Children's Earth Foundation
24/ Delaware Public Service Comm.	57/ National Parks Conservation Association, Inc.
25/ Conn. Ofc. Of Consumer Counsel	58/ Missouri Office of the Public Counsel
26/ Arizona Corp. Commission	59/ The Utility Reform Network
27/ AT&T	60/ Colorado Office of Consumer Counsel
28/ AT&T/MCI	61/ MD State Senator Paul G. Pinsky
29/ IN Office of Utility Consumer Counselor	62/ MD Speaker of the House Michael Busch
30/ Unitel (AT&T – Canada)	63/ Washington Office of Public Counsel
31/ Public Interest Advocacy Centre	64/ Industrial Customers of Northwestern Utilities
32/ U.S. General Services Administration	65/ Steering Committee of Cities
33/ Michigan Attorney General	66/ City of Chattanooga

Comparison of Inflation Expense Patterns



Otter Tail Power Company
Comparison of Accrual Accounting Versus OTP Treatment of Inflation

Line	Assumptions:	Year 1		
	Year 1 (2000) Data	2000		
1	Number of Structures	1	structure	
2	Service Life	20	years	
3	Average age of structure	0	years	
4	Remaining life	20	years	
5	Present Value of Disposal Cost Per Structure	$20,000		
6	Present Value of Future Disposal Costs L.1 * L5	$20,000		
7	Future inflation rate	5.00%	Assumed	
8	Inflated Value of Future Disposal Costs	$ 53,065.95		
9	Original Cost of Structure	$ 100,000		
10	OTP Approach Recommendation -(L8/L9)	-53.07%		

	Straight Line Recovery of Original PV of Future Removal			Inflation to Original Cost of Future Removal				Annual Expense		
Year	Original Cost of Future Removal BOY	Depreciation Expense	Accumulated Depreciation EOY	PV of Future Cost BOY	Inflation Expense	PV of Cost EOY	Cumulative Inflation	Accrual Basis Annual Expense	OTP Annual Expense	OTP Inflation Matching
2000	$20,000	$1,000	$1,000.00	$ 20,000.00	$1,000.00	$21,000.00	$1,000.00	$2,000.00	$2,653.30	$1,653.30
2001	20,000	1,000	2,000.00	21,000.00	1,050.00	22,050.00	2,050.00	2,050.00	2,653.30	1,653.30
2002	20,000	1,000	3,000.00	22,050.00	1,102.50	23,152.50	3,152.50	2,102.50	2,653.30	1,653.30
2003	20,000	1,000	4,000.00	23,152.50	1,157.63	24,310.13	4,310.13	2,157.63	2,653.30	1,653.30
2004	20,000	1,000	5,000.00	24,310.13	1,215.51	25,525.63	5,525.63	2,215.51	2,653.30	1,653.30
2005	20,000	1,000	6,000.00	25,525.63	1,276.28	26,801.91	6,801.91	2,276.28	2,653.30	1,653.30
2006	20,000	1,000	7,000.00	26,801.91	1,340.10	28,142.01	8,142.01	2,340.10	2,653.30	1,653.30
2007	20,000	1,000	8,000.00	28,142.01	1,407.10	29,549.11	9,549.11	2,407.10	2,653.30	1,653.30
2008	20,000	1,000	9,000.00	29,549.11	1,477.46	31,026.56	11,026.56	2,477.46	2,653.30	1,653.30
2009	20,000	1,000	10,000.00	31,026.56	1,551.33	32,577.89	12,577.89	2,551.33	2,653.30	1,653.30
2010	20,000	1,000	11,000.00	32,577.89	1,628.89	34,206.79	14,206.79	2,628.89	2,653.30	1,653.30
2011	20,000	1,000	12,000.00	34,206.79	1,710.34	35,917.13	15,917.13	2,710.34	2,653.30	1,653.30
2012	20,000	1,000	13,000.00	35,917.13	1,795.86	37,712.98	17,712.98	2,795.86	2,653.30	1,653.30
2013	20,000	1,000	14,000.00	37,712.98	1,885.65	39,598.63	19,598.63	2,885.65	2,653.30	1,653.30
2014	20,000	1,000	15,000.00	39,598.63	1,979.93	41,578.56	21,578.56	2,979.93	2,653.30	1,653.30
2015	20,000	1,000	16,000.00	41,578.56	2,078.93	43,657.49	23,657.49	3,078.93	2,653.30	1,653.30
2016	20,000	1,000	17,000.00	43,657.49	2,182.87	45,840.37	25,840.37	3,182.87	2,653.30	1,653.30
2017	20,000	1,000	18,000.00	45,840.37	2,292.02	48,132.38	28,132.38	3,292.02	2,653.30	1,653.30
2018	20,000	1,000	19,000.00	48,132.38	2,406.62	50,539.00	30,539.00	3,406.62	2,653.30	1,653.30
2019	20,000	1,000	20,000.00	50,539.00	2,526.95	53,065.95	33,065.95	3,526.95	2,653.30	1,653.30
		$20,000.00			$33,065.95			$53,065.95	$53,066.00	

Comparison of Inflation Expense Patterns

Year	Accrual Basis Annual Inflation	OTP Annual Inflation
2000	$1,000.00	$1,653.30
2001	1,050.00	1,653.30
2002	1,102.50	1,653.30
2003	1,157.63	1,653.30
2004	1,215.51	1,653.30
2005	1,276.28	1,653.30
2006	1,340.10	1,653.30
2007	1,407.10	1,653.30
2008	1,477.46	1,653.30
2009	1,551.33	1,653.30
2010	1,628.89	1,653.30
2011	1,710.34	1,653.30
2012	1,795.86	1,653.30
2013	1,885.65	1,653.30
2014	1,979.93	1,653.30
2015	2,078.93	1,653.30
2016	2,182.87	1,653.30
2017	2,292.02	1,653.30
2018	2,406.62	1,653.30
2019	2,526.95	1,653.30

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	SK Recommended 2007 Test Year	Difference
		a	b	c=b-a
1	Average Rate Base	$187,173,203	$187,745,238	$572,035
2	Operating Income (Before AFUDC)	$12,942,144	$13,185,453	$243,309
3	Allowance for Funds Used During Construction (AFUDC)	-	-	-
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$12,942,144	$13,185,453	$243,309
5	Overall Rate of Return (Line 4 / Line 1)	6.91%	7.02%	
6	Required Rate of Return	8.89%	8.62%	
7	Operating Income Requirement (Line 1 x Line 6)	$16,639,698	$16,183,640	($456,058)
8	Income Deficiency (Line 7 - Line 4)	$3,697,554	$2,998,186	($699,367)
9	Gross Revenue Conversion Factor	1.645413	1.645413	
10	Revenue Deficiency (Line 8 x Line 9)	$6,084,004	$4,933,256	($1,150,749)
11	Retail Related Revenues Under Present Rates	$118,309,177	$118,309,177	$0
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	5.14%	4.17%	

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Company Proposed 2007 Test Year	Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Staff Depreciation Rates	Adj. 6 Reduce Dep Expense for New Plant	Adj. 7 Charitable Contributions	Adj. 8 STB Litigation
	OPERATING REVENUES								
1	Retail Revenue	$ 118,309,177	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	13,804,432	-	-	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ 132,113,610	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ 67,714,739	$ -	$ -	$ -	$ -	$ -	$ -	$ (40,973)
5	Transmission Expenses	4,467,061	-	-	-	-	-	-	-
6	Distribution Expenses	6,727,802	-	-	-	-	-	-	-
7	Customer Accounting Expenses	4,728,770	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	2,185,290	-	-	-	-	-	-	-
9	Sales Expenses	701,476	-	-	-	-	-	-	-
10	Administration and General Expenses	13,557,519	-	-	-	-	-	-	-
11	Charitable Contributions	114,816	-	-	-	-	-	(114,816)	-
12	Depreciation Expense	10,716,072	(268,864)	(12,095)	209,145	(1,339,694)	(54,650)	-	-
13	General Taxes	3,957,594	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ 114,871,139	$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (54,650)	$ (114,816)	$ (40,973)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 17,242,470	$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 54,650	$ 114,816	$ 40,973
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ (476,372)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	213,186	-	-	-	-	-	-	-
19	Income Taxes	4,563,512	105,462	4,744	(82,037)	525,496	21,437	45,037	16,072
20	**TOTAL INCOME TAX EXPENSE**	$ 4,300,326	$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 21,437	$ 45,037	$ 16,072
21	**NET OPERATING INCOME**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
22	Allowance for Funds Used During Construction	-	-	-				-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 12,942,144	$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 33,213	$ 69,779	$ 24,901
24	**TOTAL RATE BASE**	187,173,203	1,053,257	12,095	(209,145)	1,339,694	54,650	-	-
25	Otter Tail Rate of Return	8.89%							
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
27	Rate Base Effect	$ (505,368)	$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,711	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413
29	Incremental Revenue Requirement	$ (831,539)	$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (46,898)	$ (114,816)	$ (40,973)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 9 Economic Development	Adj. 10 Employee Awards	Adj 11. Asset-Based Margins	Adj. 12 Mgmt Incentives	Adj. 13 Reverse OPEB Prepayments	Adj. 14 Remove OPEB Transition Costs	Adj. 15 Reverse MISO	Adj. 16 Reverse MISO Amort.
	OPERATING REVENUES								
1	Retail Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Electric Operating Revenue	-	-	(8,508,499)	-	-	-	-	-
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ -	$ -	$ -	$ -	$ -
	OPERATING EXPENSES								
4	Production Expenses	$ -	$ -	$ (4,375,390)	$ -	$ -	$ -	$ (256,990)	$ (309,019)
5	Transmission Expenses	-	-	-	-	-	-	-	-
6	Distribution Expenses	-	-	-	-	-	-	-	-
7	Customer Accounting Expenses	-	-	-	-	-	-	-	-
8	Customer Service and Information Expenses	-	-	-	-	-	-	-	-
9	Sales Expenses	(108,539)	-	-	-	-	-	-	-
10	Administration and General Expenses	-	(76,089)	-	(150,668)	-	-	-	-
11	Charitable Contributions	-	-	-	-	-	-	-	-
12	Depreciation Expense	-	-	-	-	-	-	-	-
13	General Taxes	-	-	-	-	-	-	-	-
14	**TOTAL OPERATING EXPENSES**	$ (108,539)	$ (76,089)	$ (4,375,390)	$ (150,668)	$ -	$ (335,705)	$ (256,990)	$ (309,019)
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 108,539	$ 76,089	$ (4,133,109)	$ 150,668	$ -	$ 335,705	$ 256,990	$ 309,019
16	**INCOME TAX EXPENSE**								
17	Investment Tax Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Deferred Income Taxes	-	-	-	-	-	-	-	-
19	Income Taxes	42,574	29,846	(1,621,212)	59,099	-	131,680	100,804	121,213
20	**TOTAL INCOME TAX EXPENSE**	$ 42,574	$ 29,846	$ (1,621,212)	$ 59,099	$ -	$ 131,680	$ 100,804	$ 121,213
21	**NET OPERATING INCOME**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
22	Allowance for Funds Used During Construction	-	-	-	-	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 65,965	$ 46,243	$ (2,511,897)	$ 91,568	$ -	$ 204,025	$ 156,186	$ 187,806
24	**TOTAL RATE BASE**	-	-	-	-	(1,678,516)	-	-	-
25	Otter Tail Rate of Return								
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
27	Rate Base Effect	$ -	$ -	$ -	$ -	$ (144,688)	$ -	$ -	$ -
28	Revenue Conversion Factor	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413	1.645413
29	Incremental Revenue Requirement	$ (108,539)	$ (76,089)	$ 4,133,109	$ (150,668)	$ (238,072)	$ (335,705)	$ (256,990)	$ (309,019)

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	Adj. 17 Reverse Non-Asset Based Margins	Adj. 18 Reverse Energy Efficiency	Total SK Adjustments	SK Adjusted 2007 Test Year
	OPERATING REVENUES				
1	Retail Revenue	$ -	$ -	$ -	$ 118,309,177
2	Other Electric Operating Revenue	-	-	(8,508,499)	5,295,933
3	**TOTAL OPERATING REVENUE**	$ -	$ -	$ (8,508,499)	$ 123,605,111
	OPERATING EXPENSES				
4	Production Expenses	$ (674,535)	$ -	$ (5,656,906)	$ 62,057,832
5	Transmission Expenses	-	-	-	4,467,061
6	Distribution Expenses	-	-	-	6,727,802
7	Customer Accounting Expenses	-	-	-	4,728,770
8	Customer Service and Information Expenses	-	(1,000,000)	(1,000,000)	1,185,290
9	Sales Expenses	-	-	(108,539)	592,937
10	Administration and General Expenses	-	-	(226,757)	13,330,762
11	Charitable Contributions	-	-	(114,816)	-
12	Depreciation Expense	-	-	(1,466,158)	9,249,914
13	General Taxes	-	-	-	3,957,594
14	**TOTAL OPERATING EXPENSES**	$ (674,535)	$ (1,000,000)	$ (8,908,882)	$ 105,962,257
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$ 674,535	$ 1,000,000	$ 400,383	$ 17,642,853
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	$ -	$ -	$ -	$ (476,372)
18	Deferred Income Taxes	-	-	-	213,186
19	Income Taxes	264,608	392,250	157,073	4,720,585
20	**TOTAL INCOME TAX EXPENSE**	$ 264,608	$ 392,250	$ 157,073	$ 4,457,400
21	**NET OPERATING INCOME**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
22	Allowance for Funds Used During Construction	-	-	-	-
23	**TOTAL AVAILABLE FOR RETURN**	$ 409,927	$ 607,750	$ 243,309	$ 13,185,453
24	**TOTAL RATE BASE**	-	-	572,035	187,745,238
25	Otter Tail Rate of Return				
26	Stipulated Rate of Return Adjustment 1.	8.62%	8.62%		
27	Rate Base Effect	$ -	$ -	$ (456,058)	
28	Revenue Conversion Factor	1.645413	1.645413		
29	Incremental Revenue Requirement	$ (674,499)	$ (1,000,000)		

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
DEVELOPMENT OF GROSS REVENUE CONVERSION FACTOR

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

Line No.	Description				OtterTail % of Incremental Gross Revenues	SK % of Incremental Gross Revenues
1	Federal Income Taxes				32.73%	32.73%
2	State Income Taxes				6.50%	6.50%
3	Total Tax Percentage				39.23%	39.23%
4	Operating Income %	=	100% - 39.23%	=	60.78%	60.78%
5	Gross Revenue Conversion Factor	=	100.00% / 60.77%	=	1.645413	1.645413

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 7

REMOVE CHARITABLE CONTRIBUTIONS

Line	Description		
	Expense Adjustment		
1	Charitable contributions included in revenue requirement		$ 114,816
2	Total Expense Adjustment - Pre Tax		$ (114,816)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		45,037
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (69,779)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (114,816)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 8

REMOVE STB LITIGATION EXPENSE

Line	Description		
	Expense Adjustment		
1	STB litigation expense included in revenue requirement		$ 40,973
2	Total Expense Adjustment - Pre Tax		$ (40,973)
3	Tax Rate	39.23%	
4	Tax Effect (L. 2 * L. 3)		16,072
5	Adjustment - Post Tax (L. 2 + L. 4)		$ (24,901)
6	Revenue Conversion Factor		1.64541341
7	Revenue Requirement (L. 5 * L. 6)		$ (40,973)

Source:
02-010(c)

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 9

ADJUST ECONOMIC DEVELOPMENT EXPENSE TO FIVE-YEAR AVERAGE

Line	Description		
	Expense Adjustment		
1	Economic Development expenses included in revenue requirement		$ 500,000
2	Five-Year Average Economic Development expenses		$ 391,461
3	Total Expense Adjustment - Pre Tax		$ (108,539)
4	Tax Rate	39.23%	
5	Tax Effect (L. 3 * L. 4)		42,574
6	Adjustment - Post Tax (L. 3 + L. 5)		$ (65,965)
7	Revenue Conversion Factor		1.64541341
8	Revenue Requirement (L. 6 * L. 7)		$ (108,539)

Calculation of 5-Year Average

2004	$ 322,774
2005	397,489
2006	427,361
2007	427,508
2008	382,173
5-year Avg.	$ 391,461

Source:

Years 2004 through 2007 from Exhibit___(BCB-1), Schedule 2. Year 2008 from response to ND 02-009.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 10

REMOVE EMPLOYEE AWARDS

Line	Description			
		Expense Adjustment		
1	Total employee gifts, awards, dinners, etc. included in revenue requirement		$	85,989
2	Less safety awards		$	(9,900)
3	Total to be excluded		$	76,089
4	Total Expense Adjustment - Pre Tax		$	(76,089)
5	Tax Rate	39.23%		
6	Tax Effect (L. 4 * L. 5)			29,846
7	Adjustment - Post Tax (L. 4 + L. 6)		$	(46,243)
8	Revenue Conversion Factor			1.64541341
9	Revenue Requirement (L. 7 * L. 8)		$	(76,089)

Source:

See response to ND 02-126, Attachment 2.

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 11

REMOVE ASSET BASED MARGINS

Line	Description		Company Proposed Amounts	Snavely King Reccomended Amounts	Total Adjustment
1	Asset-based margin - revenue		$ 8,508,499	$ -	$ (8,508,499)
2	Asset-based margin - expense		4,375,390	-	(4,375,390)
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ 4,133,109	$ -	$ (4,133,109)
4	Tax Rate	39.23%			
5	Tax Effect (L. 3 * L. 4)				(1,621,212)
6	Adjustment - Post Tax (L. 3 - L. 5)				$ 2,511,897
7	Revenue Conversion Factor				1.64541341
8	Revenue Requirement (L. 6 * L. 7)				$ 4,133,109

Source:

"4A - 2007 ND TY-15 Asset Based Margins Adj.xls"

OTTER TAIL POWER COMPANY
TEST YEAR ENDING DECEMBER 31, 2007

SK ADJUSTMENT NO. 12

REMOVE MANAGEMENT INCENTIVE PAY

Line	Description		Expense Adjustment Total Company	Expense Adjustment ND Allocation
1	Management incentive pay included in proposal		$358,248	$ 150,668
2	SK recommended management incentive pay		-	-
3	Total Net Adjustment - Pre Tax (L. 2 - L. 1)		$ (358,248)	$ (150,668)
4	Tax Rate	39.23%		
5	Tax Effect (L. 3 * L. 4)			59,099
6	Adjustment - Post Tax (L. 3 - L. 5)			$ (91,568)
7	Revenue Conversion Factor			1.64541341
8	Revenue Requirement (L. 6 * L. 7)			$ (150,668)

Calculation of ND Allocation 1/

Sub Function	Sub-Function Allocator	Sub-Function Amount	ND Allocator	ND Allocation
ADMINISTRATIVE & GENERAL EXPENSES				
SALARIES, SUPPLIES, PENSIONS & BENEFITS				
PRODUCTION	37%	134,056	40.2432%	53,949
TRANSMISSION	15%	53,451	41.2573%	22,052
DISTRIBUTION	24%	84,224	44.0292%	37,083
CUSTOMER ACCOUNTS	18%	64,055	43.2566%	27,708
CUSTOMER SERVICE & INFO	6%	22,462	43.9668%	9,876
Total Management Incentive	100%	358,248		150,668

1/ Allocation factors taken from "4A - 2007 ND TY-12 Labor Annual Increases, KPP, management incentive ADJ.xls."

Depreciation
Staff Adjustments 2, 3, 4, 5 and 6

Adj 2 Reverse Dep Allocation	Adj. 3 Reverse 2008 Dep Rates	Adj. 4 Reverse Co. 2009 Dep Rates	Adj. 5 Staff Depreciation Rates	Adj. 6 Reduce Dep Expense for New Plant
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
(268,864)	(12,095)	209,145	(1,339,694)	(48,611)
-	-	-	-	-
$ (268,864)	$ (12,095)	$ 209,145	$ (1,339,694)	$ (48,611)
$ 268,864	$ 12,095	$ (209,145)	$ 1,339,694	$ 48,611
$ -	$ -	$ -	$ -	$ -
-	-	-	-	-
105,462	4,744	(82,037)	525,496	19,068
$ 105,462	$ 4,744	$ (82,037)	$ 525,496	$ 19,068
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
-	-			
$ 163,402	$ 7,351	$ (127,108)	$ 814,198	$ 29,543
1,053,257	12,095	(209,145)	1,339,694	48,611
8.62%	8.62%	8.62%	8.62%	8.62%
$ 90,791	$ 1,043	$ (18,028)	$ 115,482	$ 4,190
1.645413	1.645413	1.645413	1.645413	1.645413
$ (119,476)	$ (10,380)	$ 179,481	$ (1,149,677)	$ (41,716)

Explanations:
Adjustment No. 2 is an exact reversal of OTP Rate Base Adjsument No. (D) and OTP Income Adjustment No. (H
Adjustment No. 3 is an exact reversal of OTP Rate Base Adjusment No. (E) and the related income adjustment t
Adjustment No. 4 is an exact reversal of OTP Rate Base Adjustment (F) and the unbundled portion of its Income
Adjustment No. 5 implements Staff's Revised depreciation rates by ratioing the revised expense to OTP's Propos

a.	OTP Present Depreciation	$	28,173,452	Response to Staff DR 02-172
b.	OTP Proposed Depreciation	$	27,672,037	Response to Staff DR 02-172
c.	1-(L.b./L.a.)		1.7797%	
d.	Staff Expense	$	24,522,162	

e.	1-(L.d./L.b.)		11.4000%
f.	Company proposed change	$	209,145
g.	L.f./L.c.	$	11,751,700
h.	L.g. X L.e.	$	1,339,694

Adjustment No. (I) to reflect Staff's depreciation rates.

i.	L.d./L.b.		88.6%
j.	Company Adj. (I)	$	479,389
k.	Correct Amount (L(i) X L.(j))	$	424,739
l.	Adjustment	$	(54,650)

l)
hat OTP bundeled into its income adjustment (J).
Adjustment (J).
;als as follows: